New York State Department of Environmental Conservation
Division of Mineral Resources

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

September 2009

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

September 2009

Lead Agency

NYS Department of Environmental Conservation
Division of Mineral Resources
Bureau of Oil & Gas Regulation
625 Broadway, 3rd Floor
Albany, New York 12233-6500

ACKNOWLEDGEMENTS

Prepared by:

BUREAU OF OIL & GAS REGULATION
NYSDEC DIVISION OF MINERAL RESOURCES

Assisted by:

NEW YORK STATE ENERGY RESEARCH & DEVELOPMENT AUTHORITY*

NEW YORK STATE DEPARTMENT OF HEALTH
Bureau of Water Supply Protection
Bureau of Toxic Substance Assessment
Bureau of Environmental Radiation Protection

NYSDEC CLIMATE CHANGE OFFICE

NYSDEC DIVISION OF AIR RESOURCES

NYSDEC DIVISION OF ENVIRONMENTAL PERMITS

NYSDEC DIVISION OF ENVIRONMENTAL REMEDIATION

NYSDEC DIVISION OF FISH, WILDLIFE & MARINE RESOURCES

NYSDEC DIVISION OF SOLID & HAZARDOUS MATERIALS

NYSDEC DIVISION OF WATER

NYSDEC DIVISION OF MINERAL RESOURCES
Regional Oil & Gas Staff
Central Office Administrative Staff

*NYSERDA research assistance contracted to Alpha Environmental, Inc.,
ICF International, URS Corporation and NTC Consultants.

Contents

Chapter 1 INTRODUCTION

1.1 Description of the Proposed Action

The Department of Environmental Conservation ("DEC" or "Department") has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus Shale for natural gas production. Wells will undergo a stimulation process known as hydraulic fracturing, which functions to release gas embedded in shale deep below the surface. While the horizontal well applications received to date are for proposed locations in Chemung, Chenango, Delaware and Tioga Counties, the Department expects to receive applications to drill in other areas, including counties where natural gas production has not previously occurred. There is also potential for development of the Utica Shale using horizontal drilling and high-volume hydraulic fracturing, and the Department is aware that this could bring use of those techniques to areas such as Otsego and Schoharie Counties, which would also be new to natural gas development. Other shale and low-permeability formations in New York may be targeted for future application of horizontal drilling and hydraulic fracturing if Marcellus and Utica development using this method is successful and the requisite infrastructure is in place. The Department has prepared this draft Supplemental Generic Environmental Impact Statement ("dSGEIS") to satisfy the requirements of the State Environmental Quality Review Act ("SEQRA") for most of these anticipated operations. In reviewing and processing permit applications for horizontal drilling and hydraulic fracturing in these deep, low-permeability formations, DEC will apply the findings and requirements of the SGEIS, including criteria and conditions for future approvals, in conjunction with the existing Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.[1]

[1] The GEIS is posted on the Department's website at http://www.dec.ny.gov/energy/45912.html .

1.2 Regulatory Jurisdiction

The State of New York's official policy, enacted into law, is "to conserve, improve and protect its natural resources and environment . . ,"[2] and it is the Department's responsibility to carry out this policy. As set forth in Environmental Conservation Law ("ECL") §3-0301(1), the Department's broad authority includes, among many other things, the power to:

- manage natural resources to assure their protection and balanced utilization,
- prevent and abate water, land and air pollution, and
- regulate storage, handling and transport of solids, liquids and gases to prevent pollution.

The Department regulates the drilling, operation and plugging of oil and natural gas wells to ensure that activities related to these wells are conducted in accordance with statutory mandates found in the ECL. In addition to protecting the environment and public health and safety, the Department is also required by Article 23 of the ECL to prevent waste of the State's oil and gas resources, to provide for greater ultimate recovery of the resources, and to protect correlative rights.[3] ECL §23-0303(2) provides that DEC's Oil, Gas and Solution Mining Law supersedes all local laws relating to the regulation of oil and gas development except for local government jurisdiction over local roads and the right to collect real property taxes. Likewise, ECL §23-1901(2) provides for supercedure of all other laws enacted by local governments or agencies concerning the imposition of a fee on activities regulated by Article 23.

As reflected by ECL §23-2101, New York is a member of the Interstate Compact to Conserve Oil and Gas, and is bound with other states by statutory adoption of the compact to participate in the mission of the Interstate Oil and Gas Compact Commission ("IOGCC") of promoting conservation and efficient recovery of domestic oil and natural gas resources, while protecting health, safety and the environment. The IOGCC advocates state-level regulation of oil and gas resources and promotes regulatory coordination and government efficiency. New York actively participates in meetings in which states, industry, environmentalists and federal officials share information and perspectives on emerging technologies and environmental issues. The IOGCC's work focuses on developing and implementing sound regulatory practices that maximize oil and natural gas production, minimize the waste of irreplaceable resources, and protect human and environmental health.

1.3 Project Location

The SGEIS and its Findings will be applicable to onshore oil and gas well drilling statewide, as are the existing GEIS and Findings. The prospective region for the extraction of natural gas from Marcellus and Utica Shales has been roughly described as an area extending from

[2] Environmental Conservation Law (ECL) §1-0101(1)

[3] Correlative rights are the rights of mineral owners to receive or recover oil and gas, or the equivalent thereof, from their owned tracts without drilling unnecessary wells or incurring unnecessary expense.

Chautauqua County eastward to Greene, Ulster and Sullivan Counties, and from the Pennsylvania border north to the approximate location of the east-west portion of the New York State Thruway between Schenectady and Auburn. However, sedimentary rock formations which may someday be developed by horizontal drilling and hydraulic fracturing exist from the Vermont/Massachusetts border up to the St. Lawrence/Lake Champlain region and west along Lake Ontario to Lake Erie. Drilling will not occur on State-owned lands which constitute the Adirondack and Catskill Forest Preserves because of the State Constitution's requirement that Forest Preserve lands be kept forever wild and not be leased or sold. In addition, the subsurface geology of the Adirondacks, New York City and Long Island renders drilling for hydrocarbons in those areas unlikely.

1.4 State Environmental Quality Review Act

1.4.1 Generic Environmental Impact Statement (GEIS)

The Department's SEQRA regulations, available at http://www.dec.ny.gov/regs/4490.html, authorize the use of generic environmental impact statements to assess the environmental impacts of separate actions having generic or common impacts. A generic environmental impact statement and its findings "set forth specific conditions or criteria under which future actions will be undertaken or approved, including requirements for any subsequent SEQR compliance."[4] When a final generic environmental impact statement has been filed, "no further SEQR compliance is required if a subsequent proposed action will be carried out in conformance with the conditions and thresholds established for such actions" in the generic environmental impact statement.[5]

Drilling and production of separate oil and gas wells, and other wells regulated under the Oil, Gas and Solution Mining Law (Article 23 of the Environmental Conservation Law) have common impacts. After a comprehensive review of all the potential environmental impacts of oil and gas drilling and production in New York, the Department found in the 1992 GEIS that issuance of a standard, individual oil or gas well drilling permit anywhere in the state, when no other permits are involved, does not have a significant environmental impact.[6] A separate finding was made that issuance of an oil and gas drilling permit for a surface location above an aquifer is also a non-significant action, based on special freshwater aquifer drilling conditions implemented by the Department.

However, the Department also found in 1992 that issuance of a drilling permit for a location in a State Parkland, in an Agricultural District, or within 2,000 feet of a municipal water supply well, or for a location which requires other DEC permits, may be significant and requires a site-specific SEQRA determination. The only instance where issuance of an individual permit to drill an oil or gas well is always significant and always requires a Supplemental Environmental

[4] 6 NYCRR 617.10(c)

[5] 6 NYCRR 617.10(d)(1)

[6] http://www.dec.ny.gov/energy/45912.html

Impact Statement ("SEIS") is when the proposed location is within 1,000 feet of a municipal water supply well. Well stimulation, including hydraulic fracturing, was expressly identified and discussed in the GEIS as part of the action of drilling a well, and the GEIS does not recommend any additional regulatory controls or find a significant environmental impact associated with this technology, which has been in use in New York State for at least 50 years.

The 1992 findings were the culmination of a 12-year effort which included extensive public scoping and research by Department staff, followed by public comment and hearings on the Draft GEIS. Major issues identified through the previous scoping process and addressed in the GEIS, as listed on page 3 of the Draft GEIS, were: impacts on water quality; impacts of drilling in sensitive areas, such as Agricultural Districts, areas of rugged topography, wetlands, drinking water watersheds, freshwater aquifers and other sensitive habitats; impacts caused by drilling and production wastes; impacts on land use; socioeconomic impacts; impacts on cultural resources and impacts on endangered species and species of concern.

1.4.2 Supplemental Generic Environmental Impact Statement (SGEIS)

The SEQRA regulations require preparation of a supplement to a final GEIS if a subsequent proposed action may have one or more significant adverse environmental impacts which were not addressed.[7] ***In 2008, the Department determined that some aspects of the current and anticipated application of horizontal drilling and high-volume hydraulic fracturing warrant further review in the context of a Supplemental Generic Environmental Impact Statement***. This determination was based primarily upon three key factors: (1) required water volumes in excess of GEIS descriptions, (2) possible drilling in the New York City Watershed, in or near the Catskill Park, and near the federally designated Upper Delaware Scenic and Recreational River, and (3) longer duration of disturbance at multi-well drilling sites. These factors and other potential impacts were listed in a publicly vetted Scope for the SGEIS. Public scoping sessions were held in November and December, 2008, at six venues in the Southern Tier and Catskills. A total of 188 verbal comments were received at these sessions. In addition, over 3,770 written comments were received (via e-mail, mail, or written comment card). All of these comments were read and reviewed by Department staff and the Final Scope was completed in February of 2009, outlining the detailed analysis required for a thorough understanding of the potentially significant environmental impacts of horizontal drilling and high-volume hydraulic fracturing in low-permeability shale.

[7] 6 NYCRR 617.10(d)(4)

1.4.3 Well Permit Applications and the Environmental Review Process

The Department's 1992 Findings Statement[8] describes the well permit and attendant environmental review processes. Each application to drill a well is an individual project, and the size of the project is defined as the surface area affected by development. The Department, which has had exclusive statutory authority since 1981 to regulate oil and gas development activities, is lead agency for purposes of SEQRA compliance.

The 1992 Findings authorized use of a shortened, program-specific environmental assessment form ("EAF"), which is required with every well drilling permit application.[9] The EAF and well drilling application form[10] do not stand alone, but are supported by the four-volume GEIS, the applicant's well location plat, proposed site-specific drilling and well construction plans, Department staff's site visit, and GIS-based location screening, using the most current data available. DEC's Oil and Gas staff consults and coordinates with staff in other Department programs when site review and the application documents indicate an environmental concern or potential need for another Department permit.

When the application documents described above demonstrate conformance with the GEIS, SEQRA is satisfied and no Determination of Significance or Negative or Positive Determination under SEQRA is required. In that event Staff files a record of consistency with the GEIS. For the permit issuance actions identified in the Findings Statement as potentially significant, or other projects where circumstances exist that prevent a consistency determination, the Department's Full Environmental Assessment Form[11] is required and a site specific determination of significance is made. Examples since 1992 where this determination has been made include underground gas storage projects, well sites where special noise mitigation measures are required, well sites that disturb more than two and a half acres in designated Agricultural Districts, and geothermal wells drilled in proximity to New York City water tunnels. Wells closer than 2,000 feet to a municipal water supply well would also require further site-specific review, but none have been permitted since 1992.

Following publication of a final SGEIS, application documents that do not demonstrate conformance with both the GEIS and the SGEIS will be subject to further SEQRA determinations, as set forth in the GEIS and SGEIS.

---

[8] http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindorig.pdf

[9] http://www.dec.ny.gov/docs/materials_minerals_pdf/eaf_dril.pdf

[10] http://www.dec.ny.gov/docs/materials_minerals_pdf/dril_req.pdf

[11] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/longeaf.pdf

2.0 Description of Proposed Action

Chapter 2 DESCRIPTION OF PROPOSED ACTION

The proposed action is the Department's issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability natural gas reservoirs. This SGEIS is focused on topics not addressed by the original GEIS, with emphasis on potential impacts associated with the large volumes of water required to hydraulically fracture horizontal shale wells using the slick water fracturing technique and the disturbance associated with multi-well sites.

2.1 Purpose

As stated in the 1992 GEIS, a generic environmental impact statement is used to evaluate the environmental effects of a program having wide application and is required for direct programmatic actions undertaken by a State agency. The SGEIS will address new activities or new potential impacts not addressed by the original GEIS and will set forth practices and mitigation designed to reduce environmental impacts to the maximum extent practicable. The SGEIS and its findings will be used to satisfy SEQR for the issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high volume hydraulic fracturing.

2.2 Public Need and Benefit

The exploration and development of natural gas resources serves the public's need for energy while providing economic and environmental benefits. Natural gas consumption comprises about 23 percent of the total energy consumption in the United States. Natural gas is used for many purposes: home space and water heating; cooking; commercial and industrial space heating; commercial and industrial processes; as a raw material for the manufacture of fertilizer, plastics, and petrochemicals; as vehicle fuel; and for electric generation. Over 50 percent of the homes in the United States use natural gas as the primary heating fuel. In 2008 U.S. natural gas consumption totaled about 23.2 trillion cubic feet, nearly matching the peak consumption of 23.3 trillion cubic feet reached in 2000.[1]

New York is the fourth largest natural gas consuming state in the nation using about 1,200 billion cubic feet of natural gas per year and accounting for about five percent of U.S. demand.[2]

In 2008 New York's 4.3 million residential customers used about 393 billion cubic feet of natural gas or 33 percent of total statewide gas use. The State's 400,000 commercial customers used about 292 billion cubic feet or 25 percent of total natural gas use. Natural gas consumption in the residential and commercial sectors in New York represents a larger proportion of the total consumption than U.S. consumption for those sectors (21 and 13 percent, respectively). The primary use of natural gas in New York for residential and small commercial customers is for space heating and is highly weather sensitive. The State's natural gas market is winter peaking with over 70 percent of residential and 60 percent of commercial natural gas consumption occurring in the five winter months (November through March).[3]

---

[1] Draft New York State Energy Plan, August 2009, p.6

[2] Draft New York State Energy Plan, August 2009, p.7

[3] Draft New York State Energy Plan, August 2009

Since natural gas is a national market, developments nationwide regarding gas supply are critical to the State. U.S. natural gas dry production totaled 20.5 trillion cubic feet in 2008, which was 6 percent higher than in 2007. About 98 percent of the natural gas produced in the United States comes from production areas in the lower 48 states. The overall U.S. dry natural gas production has been relatively flat over much of the last ten years. However, in the past few years, there has been a significant shift in gas supplies from conventional or traditional supply areas and sources to unconventional or new supply areas and sources. U.S. natural gas production from traditional, more mature and accessible natural gas supply basins, has steadily declined. However, this has been offset by increased drilling and production from new unconventional gas supply areas. In 2008 natural gas production from new supply resources totaled about 10.4 trillion cubic feet (28.5 billion cubic feet per day) or about 51 percent of the total U.S. dry natural gas production.[4]

The increased production from unconventional resources is primarily from tight sands, coal-bed methane, and shale formations. The Rocky Mountain Region is the fastest growing region for tight sands natural gas production and the predominate region for coal-bed methane natural gas production in the United States. There are at least 21 shale gas basins located in over 20 states in the United States. Currently, the most prolific shale producing areas in the country are in the southern US and include the Barnett Shale area in Texas, the Haynesville Shale in Texas and Louisiana, the Woodford Shale in Oklahoma, and the Fayetteville Shale in Arkansas. In the Appalachian region, which extends into New York, the Marcellus Shale is expected to develop into a major natural gas production area. Proven natural gas reserves for the United States totaled over 237 trillion cubic feet at the end of 2007, an increase of about 12 percent over 2006 levels. The increase in reserves was the ninth year in a row that U.S. natural gas proven reserves have increased.[5]

Over 95 percent of the natural gas supply required to meet the demands of New York natural gas customers is from other states, principally the Gulf Coast region, and Canada. The gas supply is brought to the New York market by interstate pipelines that move the gas from producing and

[4] Draft New York State Energy Plan, August 2009, p.9

[5] Draft New York State Energy Plan, August 2009, p.11

storage areas for customers, such as local distribution companies (LDCs) and electric generators, who purchase the gas supplies from gas producers and marketers.

New York natural gas production supplies about 5 percent of the State's natural gas requirements. Currently, there are about 6,700 active natural gas wells in the State. For the 2008 calendar year, total reported State natural gas production was 50.3 billion cubic feet, down 9 percent from the 2006 record total of 55.2 billion cubic feet. These figures represent an increase of over 200 percent since 1998 (16.7 billion cubic feet).[6]

The Marcellus Shale formation is attracting attention as a significant new source of natural gas production. The Marcellus Shale extends from Ohio through West Virginia and into Pennsylvania and New York. In New York, the Marcellus Shale is located in much of the Southern Tier stretching from Chautauqua and Erie counties in the west to the counties of Sullivan, Ulster, Greene and Albany in the east. According to Penn State University, the Marcellus Shale is the largest known shale deposit in the world. Engelder and Lash (2008) first estimated gas-in-place to be between 168 and 500 trillion cubic feet with a recoverable estimate of 50 tcf. While it is very early in the productive life of Marcellus Shale wells, the most recent estimates by Engelder using well production decline rates indicate a 50 percent probability that recoverable reserves could be as high as 489 trillion cubic feet.[7]

In Pennsylvania, where Marcellus Shale development is underway, Penn State found that the Marcellus gas industry generated $2.3 billion in total value, added more than 29,000 jobs, and $240 million in state and local taxes in 2008. With a substantially higher pace of development expected in 2009, economic output will top $3.8 billion, state and local tax revenues will be more than $400 million, and total job creation will exceed 48,000.[8]

The Draft 2009 New York State Energy Plan recognizes the potential benefit to New York by development of the Marcellus Shale natural gas resource:

[6] Draft New York State Energy Plan, August 2009, p.14

[7] Considine et al., 2009 p.2.

[8] Considine et al., 2009 p. 31.

> Production and use of in-state energy resources – renewable resources and natural gas – can increase the reliability and security of our energy systems, reduce energy costs, and contribute to meeting climate change, public health and environmental objectives. Additionally, by focusing energy investments on in-state opportunities, New York can reduce the amount of dollars "exported" out of the State to pay for energy resources.[9]

The Draft Energy Plan further includes a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.[10]

The New York State Commission on State Asset Maximization recommends that "Taking into account the significant environmental considerations, the State should study the potential for new private investment in extracting natural gas in the Marcellus Shale on State-owned lands, in addition to development on private lands." Depending on the geology, a typical horizontal well in the Marcellus Shale (covering approximately 80 acres) may produce 1.0 to 1.5 bcf (billion cubic feet) of gas cumulatively over the first five years in service. At a natural gas price of $6 per mcf, a 12.5 percent royalty could result in royalty income to a landowner of $750,000 to over $1 million over a five-year period.[11]

The Final report concludes that an increase in natural gas supplies would place downward pressure on natural gas prices, improve system reliability and result in lower energy costs for New Yorkers. In addition, natural gas extraction would create jobs and increase wealth to upstate landowners, and increase State revenue from taxes and landowner leases and royalties. Development of State-owned lands could provide much needed revenue relief to the State and spur economic development and job creation in economically depressed regions of the State.[12]

Broome County, New York commissioned a study entitled *Potential Economic and Fiscal Impacts from Natural Gas Production in Broome County, New York* which was released in July

---

[9] New York State Energy Planning Board, August 2009

[10] New York State Energy Planning Board, August 2009

[11] New York State Commission on State Asset Maximization, June, 2009

[12] New York State Commission on State Asset Maximization, June, 2009

2009. The report details significant potential economic impacts on the Greater Binghamton Region:

Economic and Fiscal Impacts of Gas Well Drilling Activities In Broome County, New York Over 10 Years[13]

Description	Impact 2,000 Wells	Impact 4,000 Wells
Total Spending	$ 7,000,000,000	$ 14,000,000,000
Total Economic Activity	$ 7,648,652,000	$ 15,297,304,000
Total Wages, Salaries, Benefits (labor income)	$ 396,436,000	$ 792,872,000
Total Employment (person years)	8,136	16,272
Total Property Income*	$ 605,676,000	$ 1,211,352,000
State Taxes+	$ 22,240,000	$ 44,480,000
Local Taxes+	$ 20,528,000	$ 41,056,000

**Includes royalties, rents, dividends, and corporate profits. + Includes sales, excise, property taxes, fees, and licenses.*

The local economic impacts are already being realized in some cases as exploration companies continue to lease prospective acreage in the Southern Tier and as oil and gas service companies seek to locate in the heart of the activity to better serve their customers. News reports on June 20, 2009, detailed the terms of a lease agreement between Hess Corporation and a coalition of landowners in the Towns of Binghamton and Conklin. The coalition represents some 800 residents who control more than 19,000 acres. The lease provides bonus payments of $3,500 per acre and a royalty of 20 percent. On August 26, 2009, it was reported that in Horseheads, New York, Schlumberger Technology Corporation is planning to build a $30 million facility to house $120 million worth of equipment and technology to service oil and gas exploration companies in the Southern Tier and Northern Pennsylvania. The facility will become the company's northeast headquarters.

According to Penn State, natural gas will play a pivotal role in the transformation of our economy to achieve lower levels of greenhouse gas (GHG) emissions. Natural gas has lower

[13] Broome County, 2009.

carbon emissions than both coal and oil, so that any displacement of these fuels by natural gas to supply power plants and other end-users will produce a reduction in GHG.[14]

2.3 Project Location

The SGEIS, along with the original GEIS, is applicable to onshore oil and gas well drilling statewide. Sedimentary rock formations which may someday be developed by horizontal drilling and hydraulic fracturing exist from the Vermont/Massachusetts border up to the St. Lawrence/Lake Champlain region, west along Lake Ontario to Lake Erie and across the Southern Tier and Finger Lakes regions. Drilling will not occur on State-owned lands in the Adirondack and Catskill Forest Preserves because of the State Constitution's requirement that Forest Preserve lands be kept forever wild and not be leased or sold. In addition, the subsurface geology of the Adirondacks, New York City and Long Island renders drilling for hydrocarbons in those areas unlikely.

The prospective region for the extraction of natural gas from Marcellus and Utica Shales has been roughly described as an area extending from Chautauqua County eastward to Greene, Ulster and Sullivan counties, and from the Pennsylvania border north to the approximate location of the east-west portion of the New York State Thruway between Schenectady and Auburn. The maps in Chapter 4 depict the prospective area.

2.4 Environmental Setting

Environmental resources discussed in the GEIS with respect to potential impacts from oil and gas development include: waterways/waterbodies; drinking water supplies; public lands; coastal areas; wetlands; floodplains; soils; agricultural lands; intensive timber production areas; significant habitats; areas of historic, architectural, archeological and cultural significance; clean air and visual resources.[15] Further information is provided below regarding specific aspects of the environmental setting for Marcellus and Utica Shale development and high-volume hydraulic fracturing that were determined during Scoping to require attention in the SGEIS.

[14] Considine et al., p. 2

[15] GEIS, Chapter 6 provides a broad background of these environmental resources, including the then-existing legislative protections, other than SEQRA, guarding these resources from potential impacts. Chapters 8, 9, 10, 11, 12, 13, 14 and 15 of the GEIS contain more detailed analyses of the specific environmental impacts of development on these resources, as well as the mitigation measures required to prevent these impacts.

2.4.1 Water Use Classifications[16]

Water use classifications are assigned to surface waters and groundwaters throughout New York. Surface water and groundwater sources are classified by the best use that is or could be made of the source. The preservation of these uses is a regulatory requirement in New York. Classifications of surface waters and groundwaters in New York are identified and assigned in 6 NYRCC Part 701.

In general, the discharge of sewage, industrial waste, or other wastes may not cause impairment of the best usages of the receiving water as specified by the water classifications at the location of discharge and at other locations that may be affected by such discharge. In addition, for higher quality waters, NYSDEC may impose discharge restrictions (described below) in order to protect public health, or the quality of distinguished value or sensitive waters.

A table of water use classifications, usages and restrictions follows.

[16] Text provided by URS Corporation, per NYSERDA contract

Table 2.1 - New York Water Use Classifications

Water Use Class	Water Type	Best Usages and Suitability	Notes
N	Fresh Surface	1, 2	
AA-Special	Fresh Surface	3, 4, 5, 6	Note a
A-Special	Fresh Surface	3, 4, 5, 6	Note b
AA	Fresh Surface	3, 4, 5, 6	Note c
A	Fresh Surface	3, 4, 5, 6	Note d
B	Fresh Surface	4, 5, 6	
C	Fresh Surface	5, 6, 7	
D	Fresh Surface	5, 7, 8	
SA	Saline Surface	4, 5, 6, 9	
SB	Saline Surface	4, 5, 6,	
SC	Saline Surface	5, 6, 7	
I	Saline Surface	5, 6, 10	
SD	Saline Surface	5, 8	
GA	Fresh Groundwater	11	
GSA	Saline Groundwater	12	Note e
GSB	Saline Groundwater	13	Note f
Other – T/TS	Fresh Surface	Trout/Trout Spawning	
Other – Discharge Restriction Category	All Types	N/A	See descriptions below

<u>Best Usage/Suitability Categories</u> [Column 3 of Table 2-1 above]

1. Best usage for enjoyment of water in its natural condition and, where compatible, as a source of water for drinking or culinary purposes, bathing, fishing, fish propagation, and recreation
2. Suitable for shellfish and wildlife propagation and survival, and fish survival
3. Best usage as source of water supply for drinking, culinary or food processing purposes
4. Best usage for primary and secondary contact recreation
5. Best usage for fishing.
6. Suitable for fish, shellfish, and wildlife propagation and survival.
7. Suitable for primary and secondary contact recreation, although other factors may limit the use for these purposes.
8. Suitable for fish, shellfish, and wildlife survival (not propagation)
9. Best usage for shellfishing for market purposes
10. Best usage for secondary, but not primary, contact recreation
11. Best usage for potable water supply

12. Best usage for source of potable mineral waters, or conversion to fresh potable waters, or as raw material for the manufacture of sodium chloride or its derivatives or similar products
13. Best usage is as receiving water for disposal of wastes (may not be assigned to any groundwaters of the State, unless the Commissioner finds that adjacent and tributary groundwaters and the best usages thereof will not be impaired by such classification)

Notes [Column 4 of Table 2-1 above]

a. These waters shall contain no floating solids, settleable solids, oil, sludge deposits, toxic wastes, deleterious substances, colored or other wastes or heated liquids attributable to sewage, industrial wastes or other wastes; there shall be no discharge or disposal of sewage, industrial wastes or other wastes into these waters; these waters shall contain no phosphorus and nitrogen in amounts that will result in growths of algae, weeds and slimes that will impair the waters for their best usages; there shall be no alteration to flow that will impair the waters for their best usages; there shall be no increase in turbidity that will cause a substantial visible contrast to natural conditions.

b. This classification may be given to those international boundary waters that, if subjected to approved treatment, equal to coagulation, sedimentation, filtration and disinfection with additional treatment, if necessary, to reduce naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes.

c. This classification may be given to those waters that if subjected to pre-approved disinfection treatment, with additional treatment if necessary to remove naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes.

d. This classification may be given to those waters that, if subjected to approved treatment equal to coagulation, sedimentation, filtration and disinfection, with additional treatment if necessary to reduce naturally present impurities, meet or will meet NYSDOH drinking water standards and are or will be considered safe and satisfactory for drinking water purposes.

e. Class GSA waters are saline groundwaters. The best usages of these waters are as a source of potable mineral waters, or conversion to fresh potable waters, or as raw material for the manufacture of sodium chloride or its derivatives or similar products.

f. Class GSB waters are saline groundwaters that have a chloride concentration in excess of 1,000 milligrams per liter or a total dissolved solids concentration in excess of 2,000 milligrams per liter; it shall not be assigned to any groundwaters of the State, unless NYSDEC finds that adjacent and tributary groundwaters and the best usages thereof will not be impaired by such classification.

Discharge Restriction Categories [Last Row of Table 2-1above]

Based on a number of relevant factors and local conditions, per 6 NYCRR 701.20, discharge restriction categories may be assigned to: (1) waters of particular public health concern; (2) significant recreational or ecological waters where the quality of the water is critical to maintaining the value for which the waters are distinguished; and (3) other sensitive waters where NYSDEC has determined that existing standards are not adequate to maintain water quality.

1. Per 6 NYCRR 701.22, new discharges may be permitted for waters where discharge restriction categories are assigned when such discharges result from environmental remediation projects, from projects correcting environmental or public health emergencies, or when such discharges result in a reduction of pollutants for the designated waters. In all cases, best usages and standards will be maintained.

2. Per 6 NYCRR 701.23, except for storm water discharges, no new discharges shall be permitted and no increase in any existing discharges shall be permitted.

3. Per 6 NYCRR 701.24, specified substance shall not be permitted in new discharges, and no increase in the release of the specified substance shall be permitted for any existing discharges. Storm water discharges are an exception to these restrictions. The substance will be specified at the time the waters are designated.

2.4.2 Water Quality Standards

Generally speaking, groundwater and surface water classifications and quality standards in New York are established by the United States Environmental Protection Agency (USEPA) and NYSDEC. The New York City Department of Environmental Protection (NYCDEP) defers to the New York State Department of Health (NYSDOH) for water classifications and quality standards. The most recent New York City Drinking Water Quality Report can be found at http://www.nyc.gov/html/dep/pdf/wsstate08.pdf . The Susquehanna River Basin Commission (SRBC) has not established independent classifications and quality standards. However, one of SRBC's roles is to recommend modifications to state water quality standards to improve consistency among the states. The Delaware River Basin Commission has established independent classifications and water quality standards throughout the Delaware River Basin, including those portions within NY. The relevant and applicable water quality standards and classifications include the following:

- 6NYCRR Part 703; Surface Water and Groundwater Quality Standards and Groundwater Effluent Limitations[17]
- USEPA Drinking Water Contaminants[18]
- 18CFR Part 410; DRBC Administrative Manual Part III Water Quality Regulations[19]
- 10 NYCRR Part 5; Subpart 5-1 Public Water Systems[20]
- NYCDEP Drinking Water Supply and Quality Report[21]

[17] http://www.dec.ny.gov/regs/4590.html

[18] http://www.epa.gov/safewater/contaminants/index.html

[19] http://www.state.nj.us/drbc/regs/WQRegs_071608.pdf

[20] http://www.health.state.ny.us/environmental/water/drinking/part5/subpart5.htm

[21] http://www.nyc.gov/html/dep/html/drinking_water/wsstate.shtml

2.4.3 Drinking Water[22]

The protection of drinking water sources and supplies is extremely important for the maintenance of public health, and the protection of this water use type is paramount. Chemical or biological substances that are inadvertently released into surface water or groundwater sources that are designated for drinking water use can adversely impact or disqualify such usage if there are constituents that conflict with applicable standards for drinking water. These standards are discussed below.

2.4.3.1 Federal

The Safe Drinking Water Act (SDWA), passed in 1974 and amended in 1986 and 1996, gives USEPA the authority to set drinking water standards. There are two categories of drinking water standards: primary and secondary. Primary standards are legally enforceable and apply to public water supply systems. The secondary standards are non-enforceable guidelines that are recommended as standards for drinking water. Public water supply systems are not required to comply with secondary standards unless a state chooses to adopt them as enforceable standards. New York State has elected to enforce both as MCL's and does not make the distinction.

The primary standards are designed to protect drinking water quality by limiting the levels of specific contaminants that can adversely affect public health and are known or anticipated to occur in drinking water. The determinations of which contaminants to regulate are based on peer-reviewed science research and an evaluation of the following factors:

- Occurrence in the environment and in public water supply systems at levels of concern
- Human exposure and risks of adverse health effects in the general population and sensitive subpopulations
- Analytical methods of detection
- Technical feasibility
- Impacts of regulation on water systems, the economy and public health

[22] Text primarily from URS Corporation, per NYSERDA contract, and NYSDOH

After reviewing health effects studies and considering the risk to sensitive subpopulations, USEPA sets a non-enforceable Maximum Contaminant Level Goal (MCLG) for each contaminant as a public health goal. This is the maximum level of a contaminant in drinking water at which no known or anticipated adverse effect on the health of persons would occur, and which allows an adequate margin of safety. MCLGs only consider public health and may not be achievable given the limits of detection and best available treatment technologies. The SDWA prescribes limits in terms of Maximum Contaminant Levels (MCLs) or Treatment Techniques (TTs), which are achievable at a reasonable cost, to serve as the primary drinking water standards. A contaminant generally is classified as microbial in nature or as a carcinogenic/non-carcinogenic chemical.

Secondary contaminants may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as taste, odor, or color) in drinking water. The numerical secondary standards are designed to control these effects to a level desirable to consumers.

Table 2-2 and Table 2-3 list contaminants regulated by federal primary and secondary drinking water standards.

Table 2.2 - Primary Drinking Water Standards

Microorganisms

Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
CRYPTOSPORIDIUM	0	TT
GIARDIA LAMBLIA	0	TT
Heterotrophic plate count	n/a	TT
LEGIONELLA	0	TT
Total Coliforms (including fecal coliform and E. coli)	0	5%
Turbidity	n/a	TT
Viruses (enteric)	0	TT

MCLG: Maximum contaminant level goal
MCL: Maximum contaminant level
TT: Treatment technology

Disinfection Byproducts

Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
Bromate	0	0.01
Chlorite	0.8	1
Haloacetic acids (HAA5)	n/a	0.06

Total Trihalomethanes (TTHMs)	n/a	0.08

Disinfectants

Contaminant	MRDLG (mg/L)	MRDL (mg/L)
Chloramines (as Cl_2)	4.0	4.0
Chlorine (as Cl_2)	4.0	4.0
Chlorine dioxide (as ClO_2)	0.8	0.8

MRDL: Maximum Residual Disinfectant Level
MRDLG: Maximum Residual Disinfectant Level Goal

Inorganic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Antimony	07440-36-0	0.006	0.006
Arsenic	07440-38-2	0	0.01 as of 01/23/06
Asbestos (fiber >10 micrometers)	01332-21-5	7 million fibers per liter	7 MFL
Barium	07440-39-3	2	2
Beryllium	07440-41-7	0.004	0.004
Cadmium	07440-43-9	0.005	0.005
Chromium (total)	07440-47-3	0.1	0.1
Copper	07440-50-8	1.3	TT; Action Level=1.3
Cyanide (as free cyanide)	00057-12-5	0.2	0.2
Fluoride	16984-48-8	4	4
Lead	07439-92-1	0	TT; Action Level=0.015
Mercury (inorganic)	07439-97-6	0.002	0.002
Nitrate (measured as Nitrogen)		10	10
Nitrite (measured as Nitrogen)		1	1
Selenium	07782-49-2	0.05	0.05
Thallium	07440-28-0	0.0005	0.002

Organic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
Acrylamide	00079-06-1	0	TT
Alachlor	15972-60-8	0	0.002
Atrazine	01912-24-9	0.003	0.003
Benzene	00071-43-2	0	0.005
Benzo(a)pyrene (PAHs)	00050-32-8	0	0.0002
Carbofuran	01563-66-2	0.04	0.04
Carbon tetrachloride	00056-23-5	0	0.005
Chlordane	00057-74-9	0	0.002

Organic Chemicals	Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
	Chlorobenzene	00108-907	0.1	0.1
	2,4-Dichloro-phenoxyacetic acid (2,4-D)	00094-75-7	0.07	0.07
	Dalapon	00075-99-0	0.2	0.2
	1,2-Dibromo-3-chloropropane (DBCP)	00096-12-8	0	0.0002
	o-Dichlorobenzene	00095-50-1	0.6	0.6
	p-Dichlorobenzene	00106-46-7	0.075	0.075
	1,2-Dichloroethane	00107-06-2	0	0.005
	1,1-Dichloroethylene	00075-35-4	0.007	0.007
	cis-1,2-Dichloroethylene	00156-59-2	0.07	0.07
	trans-1,2-Dichloroethylene	00156-60-5	0.1	0.1
	Dichloromethane	00074-87-3	0	0.005
	1,2-Dichloropropane	00078-87-5	0	0.005
	Di(2-ethylhexyl) adipate	00103-23-1	0.4	0.4
	Di(2-ethylhexyl) phthalate	00117-81-7	0	0.006
	Dinoseb	00088-85-7	0.007	0.007
	Dioxin (2,3,7,8-TCDD)	01746-01-6	0	0.00000003
	Diquat		0.02	0.02
	Endothall	00145-73-3	0.1	0.1
	Endrin	00072-20-8	0.002	0.002
	Epichlorohydrin		0	TT
	Ethylbenzene	00100-41-4	0.7	0.7
	Ethylene dibromide	00106-93-4	0	0.00005
	Glyphosate	01071-83-6	0.7	0.7
	Heptachlor	00076-44-8	0	0.0004
	Heptachlor epoxide	01024-57-3	0	0.0002
	Hexachlorobenzene	00118-74-1	0	0.001
	Hexachlorocyclopentadiene	00077-47-4	0.05	0.05
	Lindane	00058-89-9	0.0002	0.0002
	Methoxychlor	00072-43-5	0.04	0.04
	Oxamyl (Vydate)	23135-22-0	0.2	0.2
	Polychlorinated biphenyls (PCBs)		0	0.0005
	Pentachlorophenol	00087-86-5	0	0.001
	Picloram	01918-02-1	0.5	0.5
	Simazine	00122-34-9	0.004	0.004
	Styrene	00100-42-5	0.1	0.1
	Tetrachloroethylene	00127-18-4	0	0.005
	Toluene	00108-88-3	1	1
	Toxaphene	08001-35-2	0	0.003
	2,4,5-TP (Silvex)	00093-72-1	0.05	0.05
	1,2,4-Trichlorobenzene	00120-82-1	0.07	0.07
	1,1,1-Trichloroethane	00071-55-6	0.2	0.2
	1,1,2-Trichloroethane	00079-00-5	0.003	0.005
	Trichloroethylene	00079-01-6	0	0.005
	Vinyl chloride	00075-01-4	0	0.002

Organic Chemicals	Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
	Xylenes (total)		10	10

Radionuclides	Contaminant	MCLG (mg/L)	MCL or TT (mg/L)
	Alpha particles	none ------------ zero	15 picocuries per Liter (pCi/L)
	Beta particles and photon emitters	none ------------ zero	4 millirems per year
	Radium 226 and Radium 228 (combined)	none ------------ zero	5 pCi/L
	Uranium	zero	30 ug/L

Table 2.3 - Secondary Drinking Water Standards

Contaminant	CAS number	Standard
Aluminum	07439-90-5	0.05 to 0.2 mg/L
Chloride		250 mg/L
Color		15 (color units)
Copper	07440-50-8	1.0 mg/L
Corrosivity		noncorrosive
Fluoride	16984-48-8	2.0 mg/L
Foaming Agents (surfactants)		0.5 mg/L
Iron	07439-89-6	0.3 mg/L
Manganese	07439-96-5	0.05 mg/L
Odor		3 threshold odor number
pH		6.5-8.5
Silver	07440-22-4	0.10 mg/L
Sulfate	14808-79-8	250 mg/L
Total Dissolved Solids		500 mg/L
Zinc	07440-66-6	5 mg/L

New York State is a primacy state and has assumed responsibility for the implementation of the drinking water protection program.

2.4.3.2 New York State

Authorization to use water for a public drinking water system is subject to Article 15, Title 15 of the ECL administered by NYSDEC, while the design and operation of a public drinking water system and quality of drinking water is regulated under the State Sanitary Code 10 NYCRR, Subpart 5-1 administered by NYSDOH.[23]

Anyone planning to operate or operating a public water supply system must obtain a Water Supply Permit from NYSDEC before undertaking any of the regulated activities.

Contact with NYSDEC and submission of a Water Supply Permit application will automatically involve NYSDOH, which has a regulatory role in water quality and other sanitary aspects of a project relating to human health. Through the State Sanitary Code (Chapter 1 of 10NYCRR), NYSDOH oversees the suitability of water for human consumption. Section 5-1.30 of 10 NYCRR[24] prescribes the required minimum treatment for public water systems, which depends on the source water type and quality. To assure the safety of drinking water in New York, NYSDOH, in cooperation with its partners, the county health departments, regulates the operation, design and quality of public water supplies; assures water sources are adequately protected, and sets standards for constructing individual water supplies.

NYSDOH standards, established in regulations found at Section 5-1.51 of 10 NYCRR and accompanying Tables in Section 1.52, meet or exceed national drinking water standards. These standards address national primary standards, secondary standards and other contaminants, including those not listed in federal standards such as principal organic contaminants with specific chemical compound classification and unspecified organic contaminants.

2.4.4 Public Water Systems

Public water systems in New York range in size from that of New York City (NYC), the largest engineered water system in the nation, serving more than nine million people, to those run by municipal governments or privately-owned water supply companies serving municipalities of varying size and type, schools with their own water supply, and small retail outlets in rural areas

---

[23] 6 NYCRR 601 - http://www.dec.ny.gov/regs/4445.html

[24] 10 NYCRR 5-1.30 - http://www.health.state.ny.us/nysdoh/phforum/nycrr10.htm

serving customers water from their own wells. Privately owned, residential wells supplying water to individual households do not require a water supply permit. In total, there are nearly 10,000 public water systems in New York State. A majority of the systems (approximately 8,460) rely on groundwater aquifers, although a majority of the State's population is served by surface water sources. Public water systems include community (CWS) and non-community (NCWS) systems. NCWSs include non-transient non-community (NTNC) and transient non-community (TNC) water systems. DOH regulations contain the definitions listed in Table 2-4.

Table 2.4 - Public Water System Definition[25]

Public water system means a community, non-community or non-transient non-community water system which provides water to the public for human consumption through pipes or other constructed conveyances, if such system has at least five service connections or regularly serves an average of at least 25 individuals daily at least 60 days out of the year. Such term includes:

a. collection, treatment, storage and distribution facilities under control of the supplier of water of such system and used with such system; and
b. collection or pretreatment storage facilities not under such control which are used with such system.

Community water system (CWS) means a public water system which serves at least five service connections used by year-round residents or regularly serves at least 25 year-round residents.

Noncommunity water system (NCWS) means a public water system that is not a community water system.

Nontransient noncommunity water system (NTNC) means a public water system that is not a community water system but is a subset of a noncommunity water system that regularly serves at least 25 of the same people, four hours or more per day, for four or more days per week, for 26 or more weeks per year.

Transient noncommunity water system (TNC) means a noncommunity water system that does not regularly serve at least 25 of the same people over six months per year.

2.4.4.1 Primary and Principal Aquifers

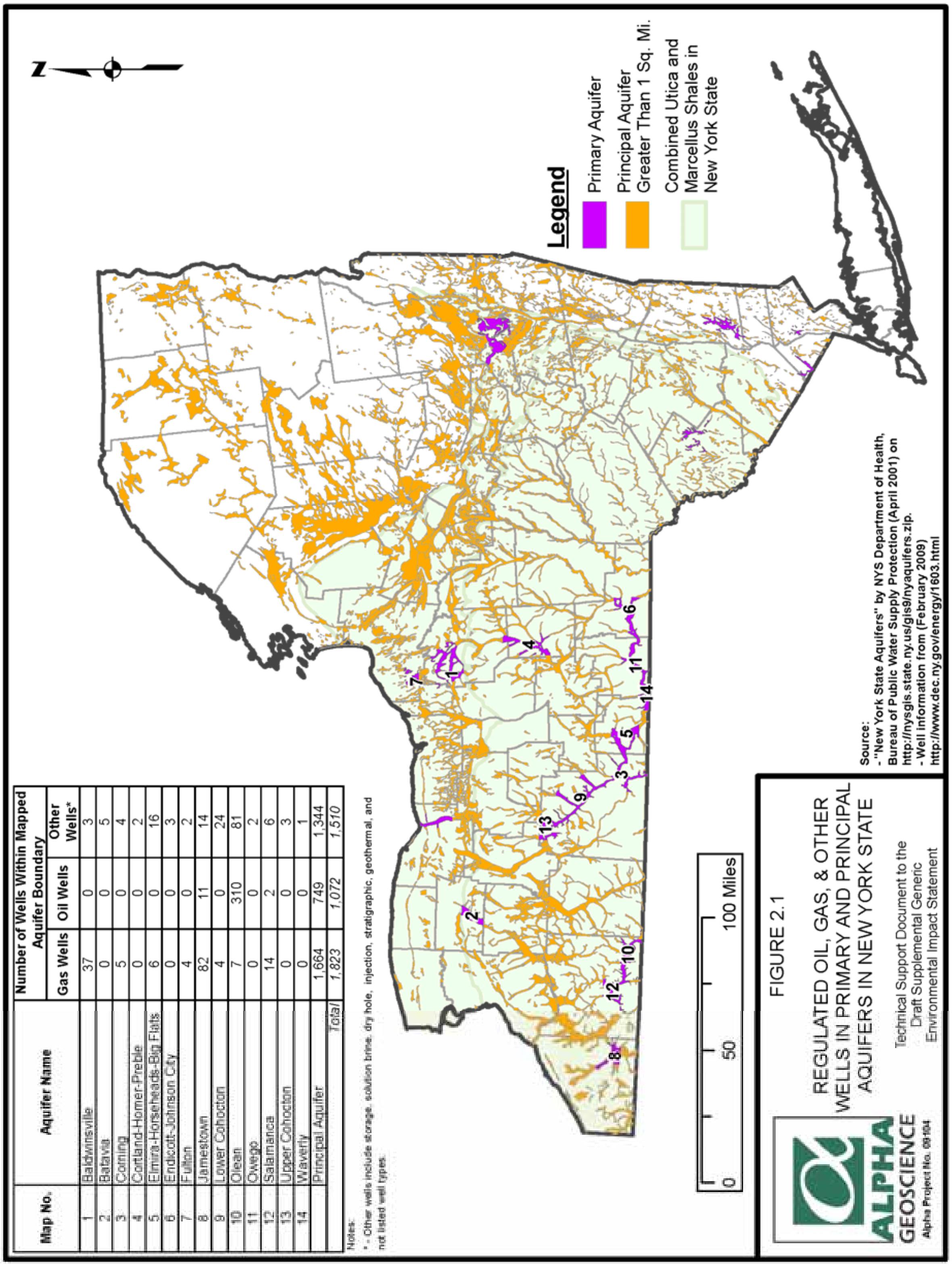
About one quarter of New Yorkers rely on groundwater as a source of potable water. In order to enhance regulatory protection in areas where groundwater resources are most productive and most vulnerable, the Department of Health, in 1980, identified 18 Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the State. These are defined in the

[25] Part 5, Subpart 5-1 Public Water Systems (Current as of: October 1, 2007); SUBPART 5-1; PUBLIC WATER SYSTEMS; 5-1.1 Definitions. (Effective Date: May 26, 2004)

Division of Water Technical and Operational Guidance Series (TOGS) 2.1.3[26] as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems."

Many Principal Aquifers have also been identified and are defined in the DOW TOGS as "highly productive, but which are not intensively used as sources of water supply by major municipal systems at the present time." Principal Aquifers are those known to be highly productive aquifers or where the geology suggests abundant potential supply, but are not presently being heavily used for public water supply. The 21 Primary and the many Principal Aquifers greater than one square mile in area within New York State (excluding Long Island) are shown on

[26] http://www.dec.ny.gov/docs/water_pdf/togs213.pdf



Map No.	Aquifer Name	Number of Wells Within Mapped Aquifer Boundary		
		Gas Wells	Oil Wells	Other Wells*
1	Baldwinsville	37	0	3
2	Batavia	0	0	5
3	Corning	5	0	4
4	Cortland-Homer-Preble	0	0	2
5	Elmira-Horseheads-Big Flats	6	0	16
6	Endicott-Johnson City	0	0	3
7	Fulton	4	0	2
8	Jamestown	82	11	14
9	Lower Cohocton	4	0	24
10	Olean	7	310	81
11	Owego	0	0	2
12	Salamanca	14	2	6
13	Upper Cohocton	0	0	3
14	Waverly	0	0	1
	Principal Aquifer	1,664	749	1,344
	Total	1,823	1,072	1,510

Notes:
* - Other wells include storage, solution brine, dry hole, injection, stratigraphic, geothermal, and not listed well types.

Figure 2.1 - Primary and Principal Aquifers

Figure 2.1. The remaining portion of the State is underlain by smaller aquifers or low-yielding groundwater sources that typically are suitable only for small community and non-community public water systems or individual household supplies. [27]

2.4.4.2 Public Water Supply Wells

NYSDOH estimates that over two million New Yorkers outside of Long Island are served by public groundwater supplies.[28] Most public water systems with groundwater sources pump and treat groundwater from wells. Public groundwater supply wells are governed by Subpart 5-1 of the State Sanitary Code under 10 NYCRR.[29]

2.4.4.3 New York City Watershed

The two reservoir systems that provide fresh water to NYC, constituting what is known as the New York City Watershed (the Watershed), located north of NYC in the Catskills and Hudson River Valley, make up the largest unfiltered drinking water supply in the nation, providing 1.3 billion gallons of water per day to nearly half the population of New York State (i.e., eight million residents within NYC and one million consumers located in Orange, Ulster, Putnam and Westchester counties). Given their importance to the public health and safety of so many New Yorkers and the continued vitality of NYC, a comprehensive, long-range watershed protection and water quality enhancement program has been established by NYC, the state and federal governments, environmental organizations, and the upstate Watershed communities.

USEPA, in consultation with NYSDOH, issued a Filtration Avoidance Determination (FAD) in July 2007 which found that NYC's watershed protection program for the Catskill/Delaware system meets the requirements for unfiltered water systems. NYC's Watershed Rules and Regulations, promulgated in May 1997 pursuant to Article 11 of the State Public Health Law, govern certain land uses and contain specific regulatory requirements intended to ensure water quality protection within the Watershed. The Department partners with NYC and NYSDOH in ensuring that the FAD requirements are fulfilled, and has committed to working with NYCDEP to ensure that activities related to gas development do not compromise the FAD.

[27] Alpha, p. 3-2

[28] http://www.health.state.ny.us/environmental/water/drinking/facts_figures.htm

[29] http://www.health.state.ny.us/environmental/water/drinking/part5/subpart5.htm

Of the two primary components of the Watershed, the East-of-Hudson system and the West-of-Hudson (WOH) system, only the WOH system overlies shale formations that potentially could be developed for gas drilling; consequently, the issues related to the potential impacts of horizontal drilling and high-volume hydraulic fracturing of shales is limited herein to the WOH Watershed.

The WOH Watershed contains six reservoirs that provide drinking water to NYC: the Ashokan, Cannonsville, Neversink, Pepacton, Rondout and Schoharie reservoirs (Figure 2.2). The total Watershed area associated with these reservoirs is approximately 1,549 square miles, exclusive of the area of the reservoirs themselves. The total Watershed area protected by City and non-City entities, including the Catskill Forest Preserve, is 472 square miles, or 30.5 percent of the total Watershed area, exclusive of the six reservoirs. The "protected" areas within the Watershed are areas where shale gas development would be prohibited because the land is either protected by the City through fee ownership or easement, or by non-City entities, which consist mostly of other public agencies (both State and local), land trusts and conservation entities. The entire Watershed area is within the fairways of shale gas development depicted in Figures 4.7 and 4.12; consequently, the 1,077 square miles of the Watershed that are not protected potentially are available for the placement of well pads for the development of shale gas reservoirs.

The New York City Watershed Rules and Regulations define the following protected waterbodies:[30]

> **Watercourse** - means a visible path through which surface water travels on a regular basis, including an intermittent stream, which is tributary to the water supply. A drainage ditch, swale or surface feature that contains water only during and immediately after a rainstorm or a snowmelt shall not be considered to be a watercourse.
>
> **Reservoir** - means any natural or artificial impoundment of water owned or controlled by the City which is tributary to the City Water supply system.

[30] Title 15 Rules of the City of New York. Section 18-16. Definitions.

Reservoir stem - means any watercourse segment which is tributary to a reservoir and lies within 500 feet or less of the reservoir.

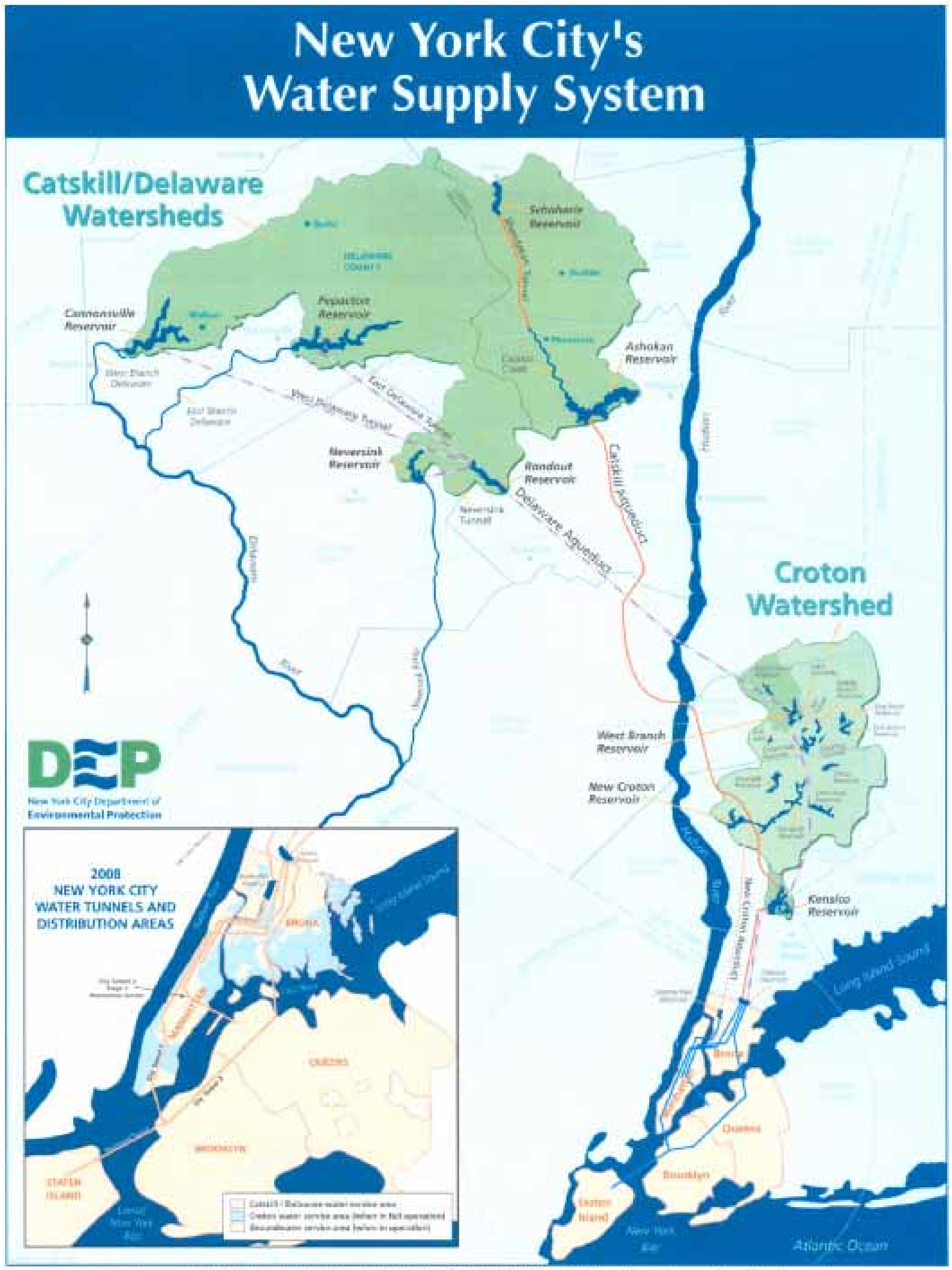


Figure 2.2 New York City's Water Supply System

Controlled lake – means a lake from which the City may withdraw water pursuant to rights acquired by the City or as a right of ownership. The controlled lakes are Kirk Lake, Lake Gleneida and Lake Gilead.

2.4.5 Private Water Wells and Domestic-Supply Springs

There are potentially tens to hundreds of thousands of private water supply wells in the State. To ensure that private water wells provide adequate quantities of water fit for consumption and intended uses, they need to be located and constructed to maintain long-term water yield and reduce the risk of contamination. Improperly constructed wells can allow for easy transport of contaminants to the well and pose a significant health risk to users. New, replacement or renovated private wells are required to be in compliance with the New York State Residential Code, NYSDOH Appendix 5-B "Standards for Water Wells," [31] installed by a certified DEC-registered water well contractor and have groundwater as the water source. However, many private water wells installed before these requirements took effect are still in use. The GEIS describes how improperly constructed private water wells are susceptible to pollution from many sources, and proposes a 150-foot setback to protect vulnerable private wells.[32]

NYSDOH includes springs – along with well points, dug wells and shore wells – as susceptible sources that are vulnerable to contamination from pathogens, spills and the effects of drought.[33]

Use of these sources for drinking water is discouraged and should be considered only as a last resort with proper protective measures. With respect to springs, NYSDOH specifically states:

[31] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm

[32] GEIS, p. 8-22

[33] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs5_susceptible_water_sources.htm

> Springs occur where an aquifer discharges naturally at or near the ground surface, and are broadly classified as either rock or earth springs. It is often difficult to determine the true source of a spring (that is, whether it truly has the natural protection against contamination that a groundwater aquifer typically has.) Even if the source is a good aquifer, it is difficult to develop a collection device (e.g., "spring box") that reliably protects against entry of contaminants under all weather conditions. (The term "spring box" varies, and, depending on its construction, would be equivalent to, and treated the same, as either a spring, well point or shore well.) Increased yield and turbidity during rain events are indications of the source being under the direct influence of surface water.[34]

Because of their vulnerability, and because in addition to their use as drinking water supplies they also supply water to wetlands, streams and ponds, the GEIS proposes a 150-foot setback.[35]

2.4.6 History of Drilling and Hydraulic Fracturing in Water Supply Areas

For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 parts per million (ppm) of sodium chloride or 1,000 ppm total dissolved solids (TDS)[36] and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS. [37] Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data. [38]

A tabulated summary of the regulated oil, gas, and other wells located within the boundaries of the Primary and Principal Aquifers in the State is provided on Figure 2.1. There are 482 oil and gas wells located within the boundaries of 14 Primary Aquifers and 2,413 oil and gas wells located within the boundaries of Principal Aquifers. Another 1,510 storage, solution brine,

---

[34] NYSDOH - http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs5_susceptible_water_sources.html

[35] GEIS, p. 8-16

[36] 6NYCRR Part 550.3(ai)

[37] 6NYCRR Part 550.3(at)

[38] Alpha, p. 3-3

injection, stratigraphic, geothermal, and other deep wells are located within the boundaries of the mapped aquifers. The remaining regulated oil and gas wells likely penetrate a horizon of potable freshwater that can be used by residents or communities as a drinking water source. These freshwater horizons include unconsolidated deposits and bedrock units. [39]

Chapter 4, on Geology, includes a generalized cross-section (Figure 4.3) across the Southern Tier of NewYork State which illustrates the depth and thickness of rock formations including the prospective shale formations.

No documented instances of groundwater contamination are recorded in the NYSDEC files from previous horizontal drilling or hydraulic fracturing projects in New York. No documented incidents of groundwater contamination in public water supply systems were reported by the NYSDOH central office and Rochester district office (NYSDOH, 2009a; NYSDOH, 2009b). References have been made to some reports of private well contamination in Chautauqua County in the 1980s that may be attributed to oil and gas drilling (Chautauqua County Department of Health, 2009; NYSDOH, 2009a; NYSDOH, 2009b; Sierra Club, undated). The reported Chautauqua County incidents, the majority of which occurred in the 1980s and which pre-date the current casing and cementing practices and fresh water aquifer supplementary permit conditions, could not be substantiated because pre-drilling water quality testing was not conducted, improper tests were run which yielded inconclusive results and/or the incidents of alleged well contamination were not officially confirmed. [40]

An operator caused turbidity (February 2007) in nearby water wells when it continued to pump compressed air for many hours through the drill string in an attempt to free a stuck drill bit at a well in the Town Of Brookfield, Madison County. The compressed air migrated through natural fractures in the shallow bedrock because the well had not yet been drilled to the permitted surface casing seat depth. This non-routine incident was reported to the Department and DEC staff were dispatched to investigate the problem. DEC shut down drilling operations and ordered the well plugged when it became apparent that continued drilling at the wellsite would cause turbidity to increase above what had already been experienced. The operator immediately

[39] Alpha, p. 3-3

[40] Alpha, p. 3-3

provided drinking water to the affected residents and subsequently installed water treatment systems in several residences. Over a period of several months the turbidity abated and water wells returned to normal. Operators that use standard drilling practices and employ good oversight in compliance with their permits will not typically cause the excessive turbidity event seen at the Brookfield wells. DEC has no records of similar turbidity caused by well drilling as occurred at this Madison County well. Geoffrey Snyder, Director Environmental Health Madison County Health Department, stated in a May 2009 email correspondence regarding the Brookfield well accident that, "Overall we find things have pretty much been resolved and the water quality back to normal if not better than pre-incident conditions."

2.4.7 Regulated Drainage Basins

New York State is divided into 17 watersheds, or drainage basins, which are the basis for various management, monitoring, and assessment activities.[41] A watershed is an area of land that drains into a body of water, such as a river, lake, reservoir, estuary, sea or ocean. The watershed includes the network of rivers, streams and lakes that convey the water and the land surfaces from which water runs off into those waterbodies. Watersheds are separated from adjacent watersheds by high points, such as mountains, hills and ridges. Groundwater flow within watersheds may not be controlled by the same topographic features as surface water flow.

Since all of New York State's land area is incorporated into the watersheds, all oil and gas drilling that has occurred since 1821 has occurred within watersheds, specifically, in 13 of the State's 17 watersheds. Mitigation measures presented in the GEIS are protective of water resources in all watersheds and river basins statewide, as are the enhanced mitigation measures identified in this document to address horizontal drilling and high-volume hydraulic fracturing. The river basins described below are subject to additional jurisdiction by existing regulatory bodies with respect to certain specific activities related to high-volume hydraulic fracturing.

The delineations of the Susquehanna and Delaware River Basins in New York are shown on Figure 2.3.

[41] See map at http://www.dec.ny.gov/lands/26561.html.

2.4.7.1 Delaware River Basin

Including Delaware Bay, the Delaware River Basin comprises 13,539 square miles in four states (New York, Pennsylvania, Delaware and New Jersey). Eighteen and a half percent of the basin, or 2,362 square miles, lies within portions of Broome, Chenango, Delaware, Schoharie, Greene, Ulster, Sullivan and Orange counties in New York. This acreage overlaps with New York City's West of Hudson Watershed; the Basin supplies about half of New York City's drinking water and 100% of Philadelphia's supply.

The Delaware River Basin Commission (DRBC) was established by a compact among the federal government, New York, New Jersey, Pennsylvania and Delaware to coordinate water resource management activities and the review of projects affecting water resources in the basin. New York is represented on the DRBC by a designee of New York State's Governor, and DEC has the opportunity to provide input on projects requiring DRBC action.

DRBC has identified its areas of concern with respect to natural gas drilling as reduction of flow in streams or aquifers, discharge or release of pollutants into ground water or surface water, and treatment and disposal of hydraulic fracturing fluid. DRBC staff will also review drill site characteristics, fracturing fluid composition and disposal strategy prior to recommending approval of shale gas development projects in the Delaware River Basin.

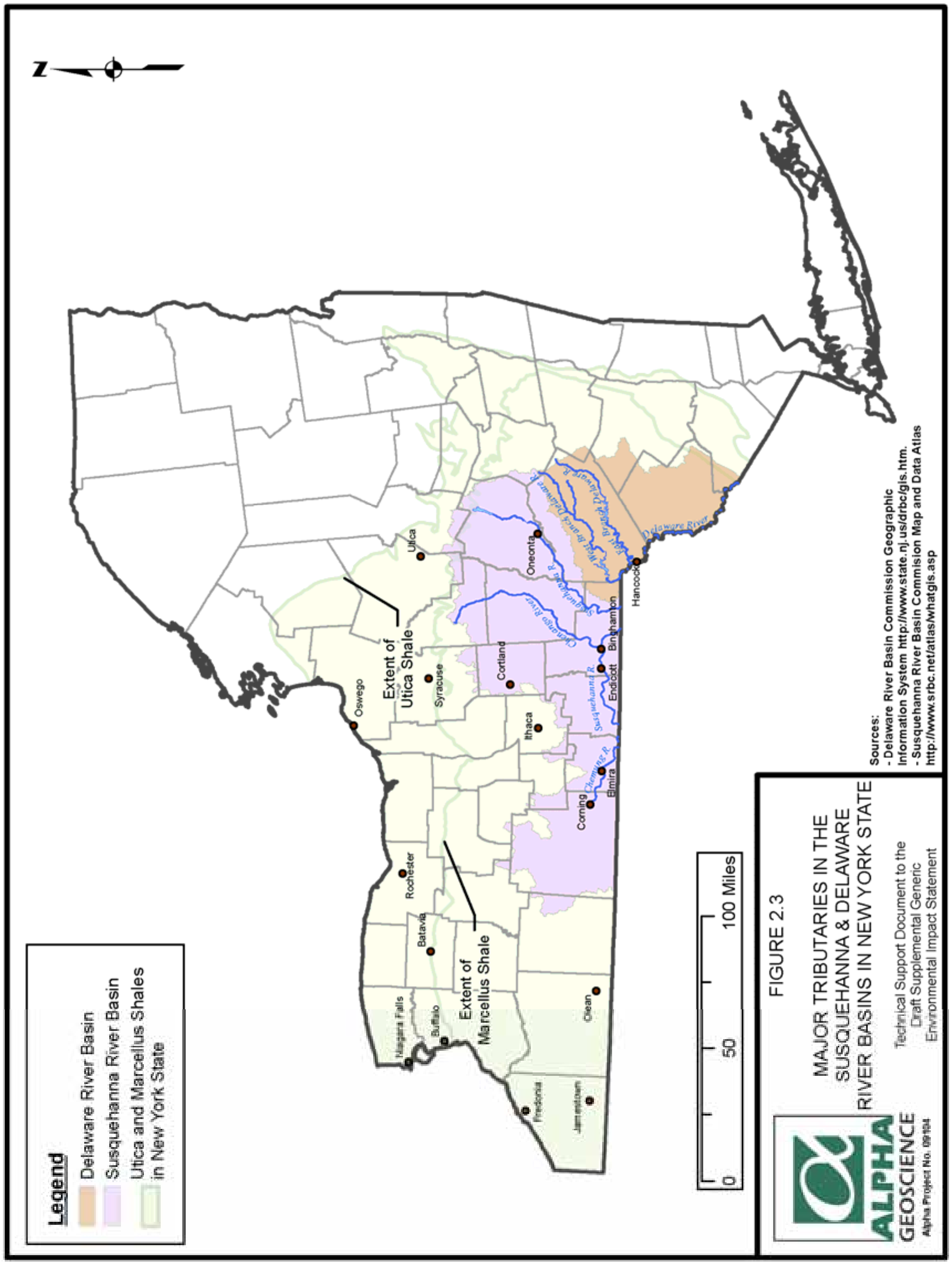


Figure 2.3 - Susquehanna and Delaware River Basins

2.4.7.2 Susquehanna River Basin

The Susquehanna River Basin comprises 27,510 square miles in three states (New York, Pennsylvania and Maryland) and drains into the Chesapeake Bay. Twenty-four percent of the basin, or 6,602 square miles, lies within portions of Allegany, Livingston, Steuben, Yates, Ontario, Schuyler, Chemung, Tompkins, Tioga, Cortland, Onondaga, Madison, Chenango, Broome, Delaware, Schoharie, Otsego, Herkimer and Oneida counties in New York.

The Susquehanna River Basin Commission (SRBC) was established by a compact among the federal government, New York, Pennsylvania and Maryland to coordinate water resource management activities and review of projects affecting water resources in the basin. New York is represented on the SRBC by a designee of DEC's Commissioner, and DEC has the opportunity to provide input on projects requiring SRBC action.

The Susquehanna River is the largest tributary to the Chesapeake Bay, with average annual flow to the Bay of over 20 billion gallons per day. Based upon existing consumptive use approvals plus estimates of other uses below the regulatory threshold requiring approval, SRBC estimates current maximum use potential in the Basin to be 882.5 million gallons per day. Projected maximum consumptive use in the Basin for gas drilling, calculated by SRBC based on twice the drilling rate in the Barnett Shale play in Texas, is about 28 million gallons per day as an annual average.[42]

2.4.7.3 Great Lakes-St. Lawrence River Basin

In New York, the Great Lakes-St. Lawrence River Basin is the watershed of the Great Lakes and St. Lawrence River, upstream from Trois Rivieres, Quebec, and includes all or parts of 34 counties, including the Lake Champlain and Finger Lakes sub-watersheds. Approximately 80 percent of New York's fresh surface water, over 700 miles of shoreline, and almost 50% of New York's lands are contained in the drainage basins of Lake Ontario, Lake Erie, and the St. Lawrence River. Jurisdictional authorities in the Great Lakes-St. Lawrence River Basin, in addition to the Department, include the Great Lakes Commission, the Great Lakes Fishery Commission, the International Joint Commission, the Great Lakes-St. Lawrence River Water

[42] http://www.srbc.net/programs/projreviewmarcellustier3.htm

Resources Compact Council, and the Great Lakes-St. Lawrence Sustainable Water Resources Regional Body.

2.4.8 Water Resources Replenishment[43]

The ability of surface water and groundwater systems to support withdrawals for various purposes, including natural gas development, is based primarily on replenishment (recharge). The Northeast region typically receives ample precipitation that replenishes surface water (runoff and groundwater discharge) and groundwater (infiltration).

The amount of water available to replenish groundwater and surface water depends on several factors and varies seasonally. A “water balance” is a common, accepted method used to describe when the conditions allow groundwater and surface water replenishment and to evaluate the amount of withdrawal that can be sustained. The primary factors included in a water balance are precipitation, temperature, vegetation, evaporation, transpiration, soil type, and slope.

Groundwater recharge (replenishment) occurs when the amount of precipitation exceeds the losses due to evapotranspiration (evaporation and transpiration by plants) and water retained by soil moisture. Typically, losses due to evapotranspiration are large in the growing season and consequently, less groundwater recharge occurs during this time. Groundwater also is recharged by losses from streams, lakes, and rivers, either naturally (in influent stream conditions) or induced by pumping. The amount of groundwater available from a well and the associated aquifer is typically determined by performing a pumping test to determine the “safe yield.” The safe yield is the amount of groundwater that can be withdrawn for an extended period without depleting the aquifer. Non-continuous withdrawal provides opportunities for water resources to recover during periods of non-pumping.

Surface water replenishment occurs directly from precipitation, from surface runoff, and by groundwater discharge to surface water bodies. Surface runoff occurs when the amount of precipitation exceeds infiltration and evapotranspiration rates. Surface water runoff typically is greater during the non-growing season when there is little or no evapotranspiration, or where soil permeability is relatively low.

---

[43] Text provided by Alpha, p. 3-26

Short-term variations in precipitation may result in droughts and floods which affect the amount of water available for groundwater and surface water replenishment. Droughts of significant duration reduce the amount of surface water and groundwater available for withdrawal. Periods of drought may result in reduced stream flow, lowered lake levels, and reduced groundwater levels until normal precipitation patterns return.

Floods may occur from short or long periods of above-normal precipitation and rapid snow melt. Flooding results in increased flow in streams and rivers and may increase levels in lakes and reservoirs. Periods of above-normal precipitation that may cause flooding also may result in increased groundwater levels and greater availability of groundwater. The duration of floods typically is relatively short compared to periods of drought.

The SRBC and DRBC have established evaluation processes and mitigation measures to assure adequate replenishment of water resources. The evaluation processes for proposed withdrawals address recharge potential and low-flow conditions. Examples of the mitigation measures utilized by the SRBC include:

- Replacement – release of storage or use of a temporary source
- Discontinue – specific to low-flow periods
- Conservation releases
- Payments
- Alternatives – proposed by applicant

Operational conditions and mitigation requirements establish passby criteria and withdrawal limits during low flow conditions. A passby flow is a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring. Passby requirements also specify low-flow conditions during which no water can be withdrawn.

2.4.9 Floodplains

Floodplains are low-lying lands next to rivers and streams. When left in a natural state, floodplain systems store and dissipate floods without adverse impacts on humans, buildings, roads or other infrastructure. Floodplains can be viewed as a type of natural infrastructure that can provide a safety zone between people and the damaging waters of a flood. Changes to the landscape outside of floodplain boundaries, like urbanization and other increases in the area of impervious surfaces in a watershed, may increase the size of floodplains. Floodplain information is found on Flood Insurance Rate Maps (FIRMs) produced by the Federal Emergency Management Agency (FEMA). These maps are organized on either a county, or a town, city or village basis and are available through the FEMA Map Service Center.[44] They may also be viewed at local government, DEC, and county and regional planning offices.

A floodplain development permit issued by a local government (town, city or village) must be obtained before commencing any floodplain development activity. This permit must comply with a local floodplain development law (often named Flood Damage Prevention Laws), designed to assure that development will not incur flood damages or cause additional off-site flood damages. These local laws, which qualify communities for participation in the National Flood Insurance Program (NFIP), require that any development in mapped, flood hazard areas be built to certain standards, identified in the NFIP regulations (44 CFR 60.3) and the Building Code of New York State and the Residential Code of New York State. Floodplain development is defined to mean any man-made change to improved or unimproved real estate, including but not limited to buildings or other structures (including gas and liquid storage tanks), mining, dredging, filling, paving, excavation or drilling operations, or storage of equipment or materials. Virtually all communities in New York with identified flood hazard areas participate in the NFIP.

The area that would be inundated by a 100-year flood (better thought of as an area that has a one percent or greater chance of experiencing a flood in any single year) is designated as a Special Flood Hazard Area. The 100-year flood is also known as the "base flood," and the elevation that the base flood reaches is known as the "base flood elevation" (BFE). The BFE is the basic standard for floodplain development, used to determine the required elevation of the lowest floor of any new or substantially improved structure. For streams where detailed hydraulic studies have identified the BFE, the 100-year floodplain has been divided into two zones, the floodway and the floodway fringe. The floodway is that area that must be kept open to convey flood waters

[44] http://msc.fema.gov

downstream. The floodway fringe is that area that can be developed in accordance with FEMA standards as adopted in local law. The floodway is shown either on the community's FIRM or on a separate “Flood Boundary and Floodway” map or maps published before about 1988. Flood Damage Prevention Laws differentiate between more hazardous floodways and other areas inundated by flood water. In particular for floodways, no encroachment can be permitted unless there is an engineering analysis that proves that the proposed development does not increase the BFE by any measurable amount at any location.

Each participating community in the State has a designated floodplain administrator. This is usually the building inspector or code enforcement official. If development is being considered for a flood hazard area, then the local floodplain administrator reviews the development to ensure that construction standards have been met before issuing a floodplain development permit.

2.4.9.1 Analysis of Recent Flood Events[45]

The Susquehanna and Delaware River Basins in New York are vulnerable to frequent, localized flash floods every year. These flash floods usually affect the small tributaries and can occur with little advance warning. Larger floods in some of the main stem reaches of these same river-basins also have been occurring more frequently. For example, the Delaware River in Delaware and Sullivan counties experienced major flooding along the main stem and in its tributaries during more than one event from September 2004 through June 2006 (Schopp and Firda, 2008). Significant flooding also occurred along the Susquehanna River during this same time period.

The increased frequency and magnitude of flooding has raised a concern for unconventional gas drilling in the floodplains of these rivers and tributaries, and the recent flooding has identified concerns regarding the reliability of the existing Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRMs) that depict areas that are prone to flooding with a defined probability or recurrence interval. The concern focused on the Susquehanna and Delaware Rivers and associated tributaries in Steuben, Chemung, Tioga, Broome, Chenango, Otsego, Delaware and Sullivan counties, New York.

[45] Text provided by Alpha, p. 3-30

2.4.9.2 Flood Zone Mapping[46]

Flood zones are geographic areas that the Federal Emergency Management Agency (FEMA) has defined according to varying levels of flood risk. These zones are depicted on a community's FIRM. Each zone reflects the severity or type of flooding in the area and the level of detailed analysis used to evaluate the flood zone.

Appendix 1 Alpha's Table 3.4 – FIRM Maps summarizes the availability of FIRMs for New York State as of July 23, 2009 (FEMA, 2009a). FIRMs are available for all communities in Broome, Delaware, and Sullivan county. The effective date of each FIRM is included in Appendix 1**.** As shown, many of the communities in New York use FIRMs with effective dates prior to the recent flood events. Natural and anthropogenic changes in stream morphology (e.g., channelization) and land use/land cover (e.g., deforestation due to fires or development) can affect the frequency and extent of flooding. For these reasons, FIRMs are updated periodically to reflect current information. Updating FIRMs and incorporation of recent flood data can take two to three years (FEMA, 2009b).

While the FIRMs are legal documents that depict flood-prone areas, the most up-to-date information on extent of recent flooding is most likely found at local or county-wide planning or emergency response departments (DRBC, 2009). Many of the areas within the Delaware and Susquehanna River Basins that were affected by the recent flooding of 2004 and 2006 lie outside the flood zones noted on the FIRMs (SRBC, 2009; DRBC, 2009; Delaware County 2009). Flood damage that occurs outside the flood zones often is related to inadequate maintenance or sizing of storm drain systems and is unrelated to streams. The FIRMs (as of July 23, 2009) do not reflect the recent flood data. Mapping the areas affected by recent flooding in the Susquehanna River Basin currently is underway and is scheduled to be published in late 2009 (SRBC, 2009). Updated FIRMs are being prepared for communities in Delaware County affected by recent flooding and are expected to be released in late 2009 (Delaware County, 2009).

According to the Division of Water, preliminary county-wide FIRM's have been developed and distributed for Sullivan and Delaware counties and are scheduled to be distributed for Broome County in September 2009. Those will become final sometime during 2010.

---

[46] Ibid.,

2.4.9.3 Seasonal Analysis[47]

The historic and recent flooding events do not show a seasonal trend. Flooding in Delaware County, which resulted in Presidential declarations of disaster and emergency between 1996 and 2006, occurred during the following months: January 1996, November 1996, July 1998, August 2003, October 2004, August 2004 and April 2005 (Tetra Tech, 2005). The Delaware River and many of its tributaries in Delaware and Sullivan counties experienced major flooding that caused extensive damage from September 2004 to June 2006 (Schopp and Firda, 2008). These data show that flooding is not limited to any particular season and may occur at any time during the year.

2.4.10 Freshwater Wetlands

Freshwater wetlands are lands and submerged lands, commonly called marshes, swamps, sloughs, bogs, and flats, supporting aquatic or semi-aquatic vegetation. These ecological areas are valuable resources, necessary for flood control, surface and groundwater protection, wildlife habitat, open space, and water resources. Freshwater wetlands also provide opportunities for recreation, education and research, and aesthetic appreciation. Adjacent areas may share some of these values and, in addition, provide a valuable buffer for the wetlands.

The Department has classified regulated freshwater wetlands according to their respective functions, values and benefits. Wetlands may be Class I, II, III or IV. Class I wetlands are the most valuable and are subject to the most stringent standards.

The Freshwater Wetlands Act (FWA), Article 24 of the Environmental Conservation Law, provides DEC and the Adirondack Park Agency with the authority to regulate freshwater wetlands in the State. The NYS Legislature passed the Freshwater Wetlands Act in 1975 in response to uncontrolled losses of wetlands and problems resulting from those losses, such as increased flooding. The FWA protects wetlands larger than 12.4 acres (5 hectares) in size, and certain smaller wetlands of unusual local importance. In the Adirondack Park, the Adirondack Park Agency (APA) regulates wetlands, including wetlands above one acre in size, or smaller wetlands if they have free interchange of flow with any surface water. The law requires DEC and APA to map those wetlands that are protected by the FWA. In addition, the law requires DEC

[47] Ibid., p. 3-31

and APA to classify wetlands. Inside the Adirondack Park, wetlands are classified according to their vegetation cover type. Outside the Park, DEC classifies wetlands according to 6 NYCRR Part 664, Wetlands Mapping and Classification.[48] Around every regulated wetland is a regulated adjacent area of 100 feet, which serves as a buffer area for the wetland.

FWA's main provisions seek to regulate those uses that would have an adverse impact on wetlands, such as filling or draining. Other activities are specifically exempt from regulation, such as cutting firewood, continuing ongoing activities, certain agricultural activities, and most recreational activities like hunting and fishing. In order to obtain an FWA permit, a project must meet the permit standards in 6NYCRR Part 663, Freshwater Wetlands Permit Requirement Regulations.[49] Intended to prevent despoliation and destruction of freshwater wetlands, these regulations were designed to:

- preserve, protect, and enhance the present and potential values of wetlands;
- protect the public health and welfare; and
- be consistent with the reasonable economic and social development of the State.

2.4.11 Visual Resources[50]

The 1992 GEIS stated that the impacts of gas drilling activities on visual resources of statewide significance are addressed on a case-by-case basis during the permit review process. When a proposed activity might have a negative visual impact, appropriate mitigating conditions are added to the permit.

In its guidance document, DEP-00-2 "Assessing and Mitigating Visual Impacts," the Department provides an inventory of aesthetic resources. It is important to note that the Department continuously updates the guidance document to add significant scenic and aesthetic resources that have not yet been designated in New York State; therefore the document should be referenced for each application. Currently, these resources can be derived from one or more of the following categories:

---

[48] 6 NYCRR 664 - http://www.dec.ny.gov/regs/4612.html

[49] 6 NYCRR 663 - http://www.dec.ny.gov/regs/4613.html

[50] NTC, 2009.

1) A property on or eligible for inclusion in the National or State Register of Historic Places [16 U.S.C. §470a et seq., Parks, Recreation and Historic Preservation Law Section 14.07].

2) State Parks [Parks, Recreation and Historic Preservation Law Section 14.07].

3) Urban Cultural Parks [Parks, Recreation and Historic Preservation Law Section 35.15];

4) The State Forest Preserve [NYS Constitution Article XIV]

5) National Wildlife Refuges [16 U.S.C. 668dd], State Game Refuges and State Wildlife Management Areas [ECL 11-2105]

6) National Natural Landmarks [36 CFR Part 62]

7) The National Park System, Recreation Areas, Seashores, Forests [16 U.S.C. 1c]

8) Rivers designated as National or State Wild, Scenic or Recreational [16 U.S.C. Chapter 28, ECL 15-2701 et seq.]

9) A site, area, lake, reservoir or highway designated or eligible for designation as scenic [ECL Article 49 or DOT equivalent and APA. Designated State Highway Roadside (Article 49 Scenic Road).

10) Scenic Areas of Statewide Significance [of Article 42 of Executive Law]

11) A State or federally designated trail, or one proposed for designation [16 U.S.C. Chapter 27 or equivalent]

12) Adirondack Park Scenic Vistas; [Adirondack Park Land Use and Development Map]

13) State Nature and Historic Preserve Areas; [Section 4 of Article XIV of State Constitution.

14) Palisades Park; [Palisades Park Commission]

15) Bond Act Properties purchased under Exceptional Scenic Beauty or Open Space category.

Many resources of the above type are found within the Marcellus and other shale regions.

Chapter 3 Proposed SEQRA Review Process

3.1 Introduction – Use of a Generic Environmental Impact Statement

The Department's regulations to implement the State Environmental Quality Review Act ("SEQRA"), available at http://www.dec.ny.gov/regs/4490.html, authorize the use of generic environmental impact statements to assess the environmental impacts of separate actions having generic or common impacts. A generic environmental impact statement and its findings "set forth specific conditions or criteria under which future actions will be undertaken or approved, including requirements for any subsequent SEQR compliance."[1] When a final generic environmental impact statement has been filed, "no further SEQR compliance is required if a subsequent proposed action will be carried out in conformance with the conditions and thresholds established for such actions" in the generic environmental impact statement.[2]

3.1.1 1992 GEIS and Findings

Drilling and production of separate oil and gas wells, and other wells regulated under the Oil, Gas and Solution Mining Law (Article 23 of the Environmental Conservation Law) have common impacts. After a comprehensive review of all the potential environmental impacts of oil and gas drilling and production in New York, the Department found in 1992 that issuance of a

[1] 6 NYCRR 617.10(c)

[2] 6 NYCRR 617.10(d)(1)

standard, individual oil or gas well drilling permit anywhere in the state, when no other permits are involved, does not have a significant environmental impact.[3] See Appendix 2. The review was conducted in accordance with SEQRA and is memorialized in the 1988 Draft and 1992 Final GEIS on the Oil, Gas and Solution Mining Program, which are incorporated by reference into this Supplement.[4] A separate finding was made that issuance of an oil and gas drilling permit for a surface location above an aquifer is also a non-significant action based on special freshwater aquifer drilling conditions implemented by the Department.

The Department further found in 1992 that issuance of a drilling permit for a location in a State Parkland, in an Agricultural District, or within 2,000 feet of a municipal water supply well, or for a location which requires other DEC permits, may be significant and requires a site-specific SEQRA determination. The only instance where issuance of an individual permit to drill an oil or gas well is always significant and always requires a Supplemental Environmental Impact Statement ("SEIS") is when the proposed location is within 1,000 feet of a municipal water supply well.

The Department also evaluated the action of leasing of state land for oil and gas development under SEQRA and found no significant environmental impact associated with that action.[5] Lease clauses and the permitting process with its attendant environmental review mitigate any potential impacts that could result from a proposal to drill. See Appendix 3.

3.1.2 Need for a Supplemental GEIS

The SEQRA regulations require preparation of a supplement to a final generic environmental impact statement if a subsequent proposed action may have one or more significant adverse environmental impacts which were not addressed.[6] The Department determined that some aspects of the current and anticipated application of horizontal drilling and high-volume hydraulic fracturing warranted further review in the context of a Supplemental Generic Environmental Impact Statement (SGEIS or Supplement). This determination was based

---

[3] http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindorig.pdf

[4] http://www.dec.ny.gov/energy/45912.html

[5] Supplemental Findings Statement, April 19, 2003 (http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindsup.pdf)

[6] 6 NYCRR 617.10(d)(4)

primarily upon three key factors: (1) required water volumes in excess of GEIS descriptions, (2) possible drilling in the New York City Watershed, in or near the Catskill Park, and near the federally designated Upper Delaware Scenic and Recreational River, and (3) longer duration of disturbance at multi-well drilling sites.

1) *Water Volumes*: The GEIS describes use of up to 80,000 gallons of water for a typical hydraulic fracturing operation. Multi-stage hydraulic fracturing of horizontal shale wells may require the use and management of millions of gallons of water for each well. This raised concerns about the volume of chemical additives present on a site, withdrawal of large amounts of water from surface water bodies, and the management and disposal of flowback water.

2) *Anticipated Drilling Locations:* While the GEIS does address drilling in drinking water watersheds, areas of rugged topography, unique habitats and other sensitive areas, oil and gas activity in the eastern third of the State was rare to non-existent at the time of publication. Although the 1992 Findings have statewide applicability, the SGEIS examines whether additional regulatory controls are needed in any of the new geographic areas of interest given the attributes and characteristics of those areas. For example, the GEIS does not address drilling in the vicinity of the New York City watershed infrastructure which exists in the prospective area for Marcellus Shale drilling.

3) *Multi-well pads:* Well operators previously suggested that as many as 16 horizontal wells could be drilled at a single well site, or pad. As stated in the following chapters, current information suggests that 6 to 10 wells per pad is the likely distribution. While this method will result in fewer disturbed surface locations, it will also result in a longer duration of disturbance at each drilling pad than if only one well were to be drilled there. ECL §23-0501(1)(b)(1)(vi) requires that all horizontal infill wells in a multi-well shale unit be drilled within three years of the date the first well in the unit commences drilling. The potential impacts of this type of multi-well project are not addressed in the GEIS.

3.2 Future SEQRA Compliance

The 1992 Findings Statement describes the well permit and attendant environmental review processes for individual oil and gas wells. Each application to drill a well is an individual project, and the size of the project is defined as the surface area affected by development. The Department, which has had exclusive statutory authority since 1981 to regulate oil and gas development activities, is lead agency for purposes of SEQRA compliance.

When application documents demonstrate conformance with the GEIS, SEQRA is satisfied and no Determination of Significance or Negative or Positive Declaration under SEQRA is required. In that event Staff files a record of consistency with the GEIS. For the permit issuance actions identified in the Findings Statement as potentially significant, or other projects where circumstances exist that prevent a consistency determination, the Department's Full Environmental Assessment Form (EAF)[7] is required and a site specific determination of significance is made. Examples since 1992 where this determination has been made include underground gas storage projects, well sites where special noise mitigation measures are required, well sites that disturb more than two and a half acres in designated Agricultural Districts, and geothermal wells drilled in proximity to New York City water tunnels. As stated above, wells closer than 2,000 feet to a municipal water supply well would also require further site-specific review, but none have been permitted since 1992.

Upon final approval and filing of this Supplemental Generic Environmental Statement, and subsequent issuance of Supplemental Findings, the following will result:

1) An EAF Addendum for High-Volume Hydraulic Fracturing will be required in addition to the other well permit application materials. The EAF Addendum will provide the information necessary for Department staff to determine the next step based on the SGEIS Supplemental Findings Statement.

2) In cases where the SGEIS Supplemental Findings Statement indicates that the GEIS and the Supplement satisfy SEQRA, Department staff will not make Determinations of Significance or issue Negative or Positive Declarations. Such projects have common potential impacts, and the GEIS and this Supplement identify common mitigation measures that will be implemented through existing regulatory programs and permit conditions. Staff will file a record of GEIS/SGEIS consistency and process the well permit application. Permit conditions will be added on a site-specific basis to ensure that the permitted activities will not have a significant effect on the environment.

3) If the proposed action is not addressed in the GEIS and the Supplement, then additional information will be required to determine whether the project may result in one or more significant adverse environmental impacts. The projects that the Department proposes fall into this category are listed in Section 3.2.3. Depending on the nature of the action, the additional information may include the Full EAF; topographic, geological or hydrogeological information; air impact analysis; chemical information or other information deemed necessary by the Department to determine the potential for a significant adverse environmental impact. A site-specific or project-specific supplemental environmental impact statement may be required.

[7] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/longeaf.pdf

4) A supplemental findings statement must be prepared if the proposed action is adequately addressed in the GEIS and the Supplement but is not addressed in the GEIS Findings Statement or the SGEIS Supplemental Findings Statement.

The following sections explain how this Supplement will be used, together with the previous GEIS, to satisfy SEQRA when high-volume hydraulic fracturing is proposed.

3.2.1 Review Parameters

In conducting SEQRA reviews, the Department will handle the topics of SGEIS applicability, individual project scope, project size and lead agency as follows.

3.2.1.1 SGEIS Applicability - Definition of High-Volume Hydraulic Fracturing

The GEIS describes 80,000 gallons as the volume of a typical water-gel fracturing job. High-volume hydraulic fracturing (or "slickwater fracturing") of horizontal wells as described in this Supplement requires millions of gallons of water. Horizontal well fracturing is done in stages, using 300,000-600,000 gallons of water per stage (Chapter 5). Fracturing a vertical well by this method could be equivalent to a single stage of a horizontal job, and could therefore require 300,000 or more gallons of water.

Potential impacts directly related to water volume are associated with water withdrawals, the volume of chemicals present on the well pad for fracturing, the handling and disposition of flowback water, and road use by trucks to haul both fresh water and flowback water. Judgment of when these impacts become substantial enough to require all of the additional controls described in this Supplement is subjective. The Department proposes the following methodology, applicable to both vertical and horizontal wells that will be subjected to hydraulic fracturing:

≤ 80,000 gallons: Not considered high-volume; GEIS mitigation is sufficient.

80,001 – 299,999 gallons: May be considered high-volume. The applicant must complete the portions of the EAF Addendum related to water source, fracture fluid makeup, distances, water wells and a fluid disposal plan. For a multi-well site, the applicant must also complete the portions related to air emissions (e.g., stack heights, particulate matter controls, etc.). The Department will determine, based on potential impacts, to what extent SGEIS mitigation measures are required to satisfy SEQRA.

≥ *300,000 gallons:* Always considered high-volume. All relevant procedures and mitigation measures set forth in this Supplement are required for the SGEIS and GEIS to satisfy SEQRA without a site-specific determination.

3.2.1.2 Project Scope

Each application to drill a well will continue to be considered as an individual project with respect to well drilling, construction, hydraulic fracturing (including additive use), and any aspects of water and materials management (source, containment and disposal) that vary between wells on a pad. Well permits will be individually issued and conditioned based on review of well-specific application materials. However, location screening for well pad setbacks and other required permits, review of access road location and construction, and the required stormwater permit coverage will be for the well pad based on submission of the first well permit application for the pad.

The only two cases where the project scope extends beyond the well pad and its access road are when the application documents propose surface water withdrawals or centralized flowback water surface impoundments that have not been previously approved by the Department. Such proposed withdrawals and impoundments will be considered part of the project scope for the first well permit application that indicates their use, and all well permit applications that propose their use will be considered incomplete until the Department has approved the withdrawal or the impoundment.

Chapter 3 of the GEIS and Section 1.5 of the Final Scope explain why gathering lines, compressor stations and pipelines are not within the scope of project review for well permit applications by the Department. Chapter 5 of this Supplement describes the facilities likely to be associated with a multi-well shale gas production site, and also provides details on the Public Service Commission's environmental review process for these facilities.

3.2.1.3 Size of Project

The size of the project will continue to be defined as the surface acreage affected by development, including the well pad, the access roads, and any other physical alteration necessary. The Department's well drilling and construction requirements, including the supplementary permit conditions proposed herein, preclude any subsurface impacts other than the permitted action to recover hydrocarbons. Most wells will be drilled on multi-well pads, described in Chapter 5 as likely to be between 4 and 5 acres in size, with pads larger than 5 acres possible, during the drilling and hydraulic fracturing stages of operations. Average production pad size, after reclamation, is likely to be between 1 and 3 acres. Access road acreage depends on the location, the length of the road and other factors. In general, each 150 feet of access road adds $1/10^{th}$ of an acre to the total surface acreage disturbance.

Centralized flowback water surface impoundments, when included in the project scope, may be as large as five acres for the impoundment itself, plus the acreage necessary for the access road, work areas, and to restrict access.

Surface water withdrawal sites will generally consist of hydrants, meters, power facilities, a gravel pad for water truck access, and possibly one or more storage tanks. These sites would generally be expected to be rather small, less than an acre or two in size.

3.2.1.4 Lead Agency

In 1981, the Legislature gave exclusive authority to the Department to regulate the oil, gas and solution mining industries under ECL §23-0303(2). Thus, only the Department has jurisdiction to grant drilling permits for wells subject to Article 23, except within State Parklands. The criteria for lead agency specify that the lead agency should be the one that has the broadest governmental powers for investigation into the impacts and the greatest capability for the most through environmental assessment of the action. These criteria would support the Department as lead agency. However, if the proposed action falls under the jurisdiction of more than one agency, based, for example, on the need for a local floodplain development permit, the lead agency must be determined by agreement among the involved agencies. An involved agency has the obligation to ensure that the lead agency is aware of all issues of concern to the involved agency. To the extent practicable, the Department will actively seek lead agency designation consistent with the general intent of Chapter 846 of the Laws of 1981.

3.2.2 EAF Addendum

The 1992 Findings authorized use of a shortened, program-specific environmental assessment form ("EAF"), which is required with every well drilling permit application.[8] (See Appendices 2 and 5). The EAF and well drilling application form[9] do not stand alone, but are supported by the four-volume GEIS, the applicant's well location plat, proposed site-specific drilling and well construction plans, Department staff's site visit, and GIS-based location screening, using the most current data available. Oil and gas staff consults and coordinates with staff in other Department programs when site review and the application documents indicate an environmental concern or potential need for another Department permit.

The Department has developed an EAF Addendum for gathering and compiling the information needed for two purposes: (1) to evaluate high-volume hydraulic fracturing projects in the context of this SGEIS and its Supplemental Findings Statement with respect to SEQRA, and (2) to identify the required site-specific mitigation measures. The EAF Addendum will be required as follows:

1) With the application to drill the first well on a pad proposed for high-volume hydraulic fracturing;

2) With the applications to drill subsequent wells on the pad for high-volume hydraulic fracturing if any of the information changes; and

3) Prior to high-volume re-fracturing of an existing well.

Categories of information required with the EAF addendum are summarized below, and Appendix 6 provides a full listing of the proposed EAF Addendum requirements.

3.2.2.1 Hydraulic Fracturing Information

Required information will include the minimum depth and elevation of the top of the fracture zone, estimated maximum depth and elevation of the bottom of potential fresh water,

---

[8] http://www.dec.ny.gov/docs/materials_minerals_pdf/eaf_dril.pdf

[9] http://www.dec.ny.gov/docs/materials_minerals_pdf/dril_req.pdf

identification of the proposed fracturing service company and additive products, the proposed volume of fracturing fluid and percent by weight of water, proppants and each additive.

3.2.2.2 Water Source Information

The operator will be required to identify the source of water used to be used for hydraulic fracturing, and provide information about any newly proposed surface water source that has not been previously approved by the Department as part of a well permit application. The proposed withdrawal location, information about the size of the upstream drainage area and available stream gauge data will be required to demonstrate the operator's compliance relative to stream flow and the narrative flow standard in 6 NYCRR 703.2.

3.2.2.3 Distances

Distances to the following resources or cultural features will be required, along with a topographic map of the area showing the well pad, well location, and scaled distances to the relevant resources and features.

- Surface location of proposed well to any known water well or domestic supply spring within 2,640 feet;

- Closest edge of well pad to:

    - Any water supply reservoir within 1,320 feet (includes reservoir stem and controlled lake in NYC Watershed),

    - Any perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet (includes watercourse in NYC Watershed),

    - Any occupied structures or places of assembly within 1,320 feet; and

- Capacity of rig fuel tank and distance to:

    - Any primary or principal aquifer, public or private water well, domestic-supply spring, reservoir, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned tank location (include reservoir stem, controlled lake and watercourse in NYC Watershed).

3.2.2.4 Water Well Information

The EAF addendum for high-volume hydraulic fracturing will require evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within half a mile (2,640 feet) of any proposed drilling location. The operator will be required to identify the wells and provide available information about their depth, completed interval and use. Use information will include whether the well is public or private, community or non-community and the type of facility or establishment if it is not a private residence. Information sources available to the operator include:

- direct contact with municipal officials,
- direct communication with property owners and tenants,
- communication with adjacent lessees,
- EPA's Safe Drinking Water Act Information System database, available at http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY , and
- DEC's Water Well Information search wizard, available at http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty .

Upon receipt of a well permit application, Department staff will compare the operator's well list to internally available information and notify the operator of any discrepancies or additional wells that are indicated within half a mile of the proposed well pad. The operator will be required to amend its EAF Addendum accordingly.

3.2.2.5 Fluid Disposal Plan

The Department's oil and gas regulations, specifically 6 NYCRR 554.1(c)(1), require a fluid disposal plan to be approved by the Department prior to well permit issuance for "any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in sufficient quantities to be deleterious to the surrounding environment . . ." To fulfill this obligation, the EAF Addendum will require information about flowback water disposition, including:

- Planned transport off of well pad (truck or piping), and information about any proposed piping;

- Planned disposition (e.g., treatment facility, disposal well, reuse, centralized surface impoundment or centralized tank facility);

- Identification and permit numbers for any proposed treatment facility or disposal well located in New York; and

- Location and detailed construction and operational information for any proposed centralized flowback water surface impoundment located in New York.

3.2.2.6 Operational Information

Other required information about well pad operations will include:

- Information about the planned construction and capacity of the reserve pit;

- Information about the number and individual and total capacity of receiving tanks on the well pad for flowback water;

- Stack heights for: drilling rig and hydraulic fracturing engines, flowback vent/flare, glycol dehydrator. If proposed flowback vent/flare stack height is less than 30 feet, then documentation that previous drilling at the pad did not encounter H2S is required;

- Description of planned public access restrictions, including physical barriers and distance to edge of well pad; and

- Description of other control measures planned to reduce particulate matter emissions during the hydraulic fracturing process.

3.2.2.7 Invasive Species Survey and Map

The Department will require that well operators submit, with the EAF Addendum, a comprehensive survey of the entire project site, documenting the presence and identity of any invasive plant species. As described in Chapter 7, this survey will establish a baseline measure of percent aerial coverage and, at a minimum, must include the plant species identified on the Interim List of Invasive Plant Species in New York State. A map (1:24,000) showing all occurrences of invasive species within the project site must be produced and included with the survey as part of the EAF Addendum.

3.2.2.8 Required Affirmations

The EAF Addendum will require operator affirmations to address the following:

- pass by flow for surface water withdrawals,
- review of local floodplain maps,
- review of local comprehensive, open space and/or agricultural plan or similar policy documents,
- residential water well sampling and monitoring,
- access road location,
- stormwater permit coverage,
- use of ultra-low sulfur fuel,
- preparation of site plans to address visual and noise impacts, invasive species mitigation and greenhouse gas emissions, and
- adherence to all well permit conditions.

3.2.3 Projects Requiring Site-Specific SEQRA Determinations

The Department proposes that site-specific environmental assessments and SEQRA determinations be required for the high-volume hydraulic fracturing projects listed below, regardless of the target formation, the number of wells drilled on the pad and whether the wells are vertical or horizontal.

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

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

3) Any proposed centralized flowback water surface impoundment. Emphasis of the initial review will be on proposed additive chemistry relative to potential emissions of Hazardous Air Pollutants. Additional review of site topography, geology and hydrogeology will be required for any proposed centralized flowback water surface impoundment at the following locations:

   a) within 1,000 feet of a reservoir;

b) within 500 feet of a perennial or intermittent stream, wetland, storm drain, lake or pond, or within 300 feet of a public or private water well or domestic supply spring;

4) Any proposed well pad within 300 feet of a reservoir, reservoir stem or controlled lake;[10]

5) Any proposed well pad within 150 feet of a private water well, domestic-use spring, watercourse, perennial or intermittent stream, storm drain, lake or pond;[11]

6) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7; and

7) Any proposed well location determined by NYCDEP to be within 1,000 feet of subsurface water supply infrastructure.

In addition, the Department will continue to review applications in accordance with its 1992 finding that issuance of a permit to drill less than 1,000 feet from a municipal water supply well is considered "always significant" and requires a site-specific Supplemental Environmental Impact Statement (SEIS) dealing with groundwater hydrology, potential impacts and mitigation measures. Any proposed well location between 1,000 and 2,000 feet from a municipal water supply well requires a site-specific assessment and SEQRA determination, and may require a site-specific SEIS. The GEIS provides the discretion to apply the same process to other public water supply wells. The Department will continue to exercise its discretion regarding applicability to other public supply wells (i.e., community and non-community water supply system wells) when information is available.

The Department is not proposing to alter its 1992 Findings that proposed disposal wells require individual site-specific review or that proposed disturbances larger than 2.5 acres in designated Agricultural Districts require a site-specific SEQRA determination. Likewise, proposed projects that require other Department permits will continue to require site-specific SEQRA determinations regarding the activities covered by those permits. No site-specific determination is necessary when coverage under a general stormwater permit is required, as the Department issues its general permits pursuant to a separate process.

[10] The terms "reservoir stem" and "controlled lake" as used here are only applicable in the New York City Watershed, as defined by NYC's Watershed rules and regulations. See Section 2.4.4.3.

[11] The term "watercourse" as used here is only applicable in the New York City Watershed, as defined by NYC's Watershed rules and regulations. See Section 2.4.4.3.

Chapter 4 GEOLOGY

This Chapter supplements and expands upon Chapter 5 of the GEIS. Sections 4.1 through 4.5 and the accompanying figures and tables were provided in their entirety by Alpha Environmental, Inc., under contract to NYSERDA to assist the Department with research related to this SGEIS.[1] Alpha's citations are retained for informational purposes, and are listed in the "consultants' references" section of the Bibliography. Section 4.6 discusses how Naturally Occurring Radioactive Materials (NORM) in Marcellus Shale Marcellus Shale is addressed in the SGEIS.

The influence of natural geologic factors with respect to hydraulic fracture design and subsurface fluid mobility is discussed Chapter 5, specifically in Sections 5.8 (hydraulic fracture design) and 5.11.1.1 (subsurface fluid mobility).

4.1 Introduction

The natural gas industry in the US began in 1821 with a well completed by William Aaron Hart in the upper Devonian Dunkirk Shale in Chautauqua County. The "Hart" well supplied businesses and residents in Fredonia, New York with natural gas for 37 years. Hundreds of shallow wells were drilled in the following years into the shale along Lake Erie and then southeastward into western New York. Shale gas fields development spread into Pennsylvania, Ohio, Indiana, and Kentucky. Gas has been produced from the Marcellus since 1880 when the first well was completed in the Naples field in Ontario County. Eventually, as other formations were explored, the more productive conventional oil and natural gas fields were developed and shale gas (unconventional natural gas) exploration diminished.

The US Energy Research and Development Administration (ERDA) began to evaluate gas resources in the US in the late 1960s. The Eastern Gas Shales Project was initiated in 1976 by the ERDA (later the US Department of Energy) to assess Devonian and Mississippian black shales. The studies concluded that significant natural gas resources were present in these tight formations.

The interest in development of shale gas resources increased in the late 20th and early 21st century as the result of an increase in energy demand and technological advances in drilling and

[1] Alpha, 2009

well stimulation. The total unconventional natural gas production in the US increased by 65% and the proportion of unconventional gas production to total gas production increased from 28% in 1998 to 46% in 2007.[2]

A description of New York State geology and its relationship to oil, gas, and salt production is included in the 1992 GEIS. The geologic discussion provided herein supplements the information as it pertains to gas potential from unconventional gas resources. Emphasis is placed on the Utica and Marcellus shales because of the widespread distribution of these units in New York.

4.2 Black Shales

Black shales are fine-grained sedimentary rocks that contain high levels of organic carbon. The fine-grained material and organic matter accumulate in deep, warm, quiescent marine basins. The warm climate favors the proliferation of plant and animal life. The deep basins allow for an upper aerobic (oxygenated) zone that supports life and a deeper anaerobic (oxygen-depleted) zone that inhibits decay of accumulated organic matter. The organic matter is incorporated into the accumulating sediments and is buried. Pressure and temperature increase and the organic matter is transformed by slow chemical reactions into liquid and gaseous petroleum compounds as the sediments are buried deeper. The degree to which the organic matter is converted is dependent on the maximum temperature, pressure, and burial depth. The extent that these processes have transformed the carbon in the shale is represented by the thermal maturity and transformation ratio of the carbon. The more favorable gas producing shales occur where the total organic carbon (TOC) content is at least 2% and where there is evidence that a significant amount of gas has formed and been preserved from the TOC during thermal maturation.[3]

Oil and gas are stored in isolated pore spaces or fractures and adsorbed on the mineral grains.[4] Porosity (a measure of the void spaces in a material) is low in shales and is typically in the range of 0 to 10 percent.[5] Porosity values of 1 to 3 percent are reported for Devonian shales in the

[2] Alpha, 2009

[3] Alpha, 2009

[4] Alpha, 2009

[5] Alpha, 2009

Appalachian Basin.[6] Permeability (a measure of a material's ability to transmit fluids) is also low in shales and is typically between 0.1 to 0.00001 millidarcy (md).[7] Hill et al. (2002) summarized the findings of studies sponsored by NYSERDA that evaluated the properties of the Marcellus Shale. The porosity of core samples from the Marcellus in one well in New York ranged from 0 to 18%. The permeability of Marcellus Shale ranged from 0.0041 md to 0.216 md in three wells in New York State.

Black shale typically contains trace levels of uranium that is associated with organic matter in the shale.[8] The presence of naturally occurring radioactive materials (NORM) induce a response on gamma-ray geophysical logs and is used to identify, map, and determine thickness of gas shales.

The Appalachian Basin was a tropical inland sea that extended from New York to Alabama (Figure 4.1). The tropical climate of the ancient Appalachian Basin provided favorable conditions for generating the organic matter, and the erosion of the mountains and highlands bordering the basin provided clastic material for deposition. The sedimentary rocks that fill the basin include shales, siltstones, sandstones, evaporites, and limestones that were deposited as distinct layers that represent several sequences of sea level rise and fall. Several black shale formations, which may produce natural gas, are included in these layers.[9]

---

[6] Alpha, 2009

[7] Alpha, 2009

[8] Alpha, 2009

[9] Alpha, 2009

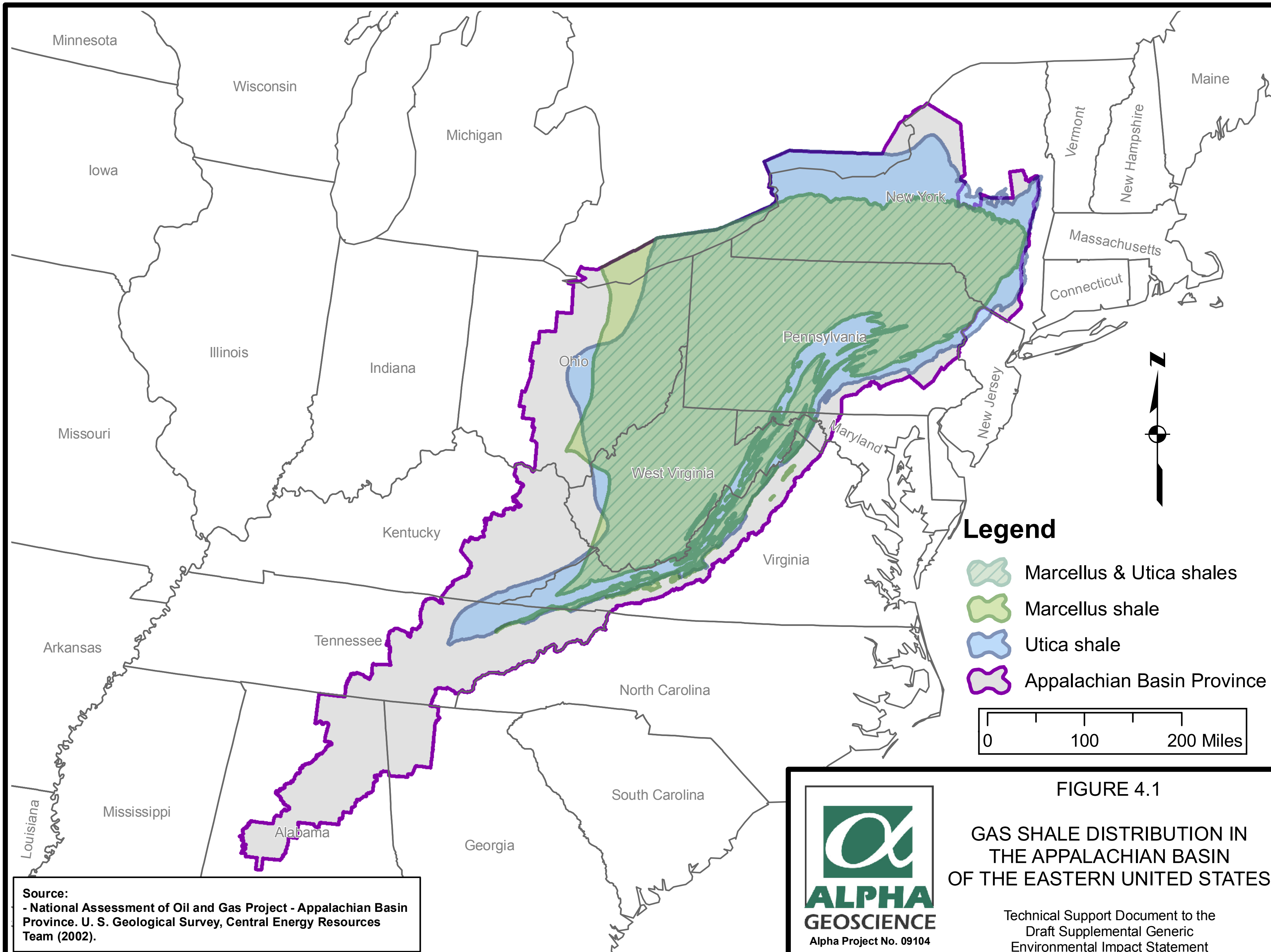


FIGURE 4.1

GAS SHALE DISTRIBUTION IN THE APPALACHIAN BASIN OF THE EASTERN UNITED STATES

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Source:
- National Assessment of Oil and Gas Project - Appalachian Basin Province. U. S. Geological Survey, Central Energy Resources Team (2002).

The stratigraphic column for New York State is shown in Figure 4.2 and includes oil and gas producing horizons. Figure 4.3 is a generalized cross-section from west to east across the southern tier of New York State and shows the variation of thickness and depth of the various stratigraphic units.

The Ordovician-aged Utica Shale and the Devonian-aged Marcellus Shale are of particular interest because of recent estimates of natural gas resources and because these units extend throughout the Appalachian Basin from New York to Tennessee. There are a number of other black shale formations (Figures 4.2 and 4.3) in New York that may produce natural gas on a localized basis.[10] The following sections describe the Utica and Marcellus shales in greater detail.

4.3 Utica Shale

The Utica Shale is an upper Ordovician-aged black shale that extends across the Appalachian Plateau from New York and Quebec, Canada, south to Tennessee. It covers approximately 28,500 square miles in New York and extends from the Adirondack Mountains to the southern tier and east to the Catskill front (Figure 4.4). The Utica shale is exposed in outcrops along the southern and western Adirondack Mountains, and it dips gently south to depths of more than 9,000 feet in the southern tier of New York.

The Utica shale is a massive, fossiliferous, organic-rich, thermally-mature, black to gray shale. The sediment comprising the Utica shale was derived from the erosion of the Taconic Mountains at the end of the Ordovician, approximately 440 to 460 million years ago. The shale is bounded below by Trenton Group strata and above by the Lorraine Formation and consists of three members in New York State that include: Flat Creek Member (oldest), Dolgeville Member, and the Indian Castle Member (youngest).[11] The Canajoharie shale and Snake Hill shale are found in the eastern part of the state and are lithologically equivalent, but older than the western portions of the Utica.[12]

---

[10] Alpha, 2009

[11] Alpha, 2009

[12] Alpha, 2009

There is some disagreement over the division of the Utica shale members. Smith & Leone (2009) divide the Indian Castle Member into an upper low-organic carbon regional shale and a high-organic carbon lower Indian Castle. Nyahay et al. (2007) combines the lower Indian Castle Member with the Dolgeville Member. Fisher (1977) includes the Dolgeville as a member of the Trenton Group. The stratigraphic convention of Smith and Leone is used in this document.

Units of the Utica shale have abundant pyrite, which indicate deposition under anoxic conditions. Geophysical logs and cutting analyses indicate that the Utica Shale has a low bulk density and high total organic carbon content.[13]

The Flat Creek and Dolgeville Members are found south and east of a line extending approximately from Steuben County to Oneida County (Figure 4.4). The Dolgeville is an interbedded limestone and shale. The Flat Creek is a dark, calcareous shale in its western extent and grades to a argillaceous calcareous mudstone to the east. These two members are time-equivalent and grade laterally toward the west into Trenton limestones.[14] The lower Indian Castle Member is a fissile, black shale and is exposed in road cuts, particularly at the New York State Thruway (I-90) exit 29A in Little Falls. Figure 4.5 shows the depth to the base of the Utica Shale.[15] This depth corresponds approximately with the base of the organic-rich section of the Utica Shale.

[13] Alpha, 2009

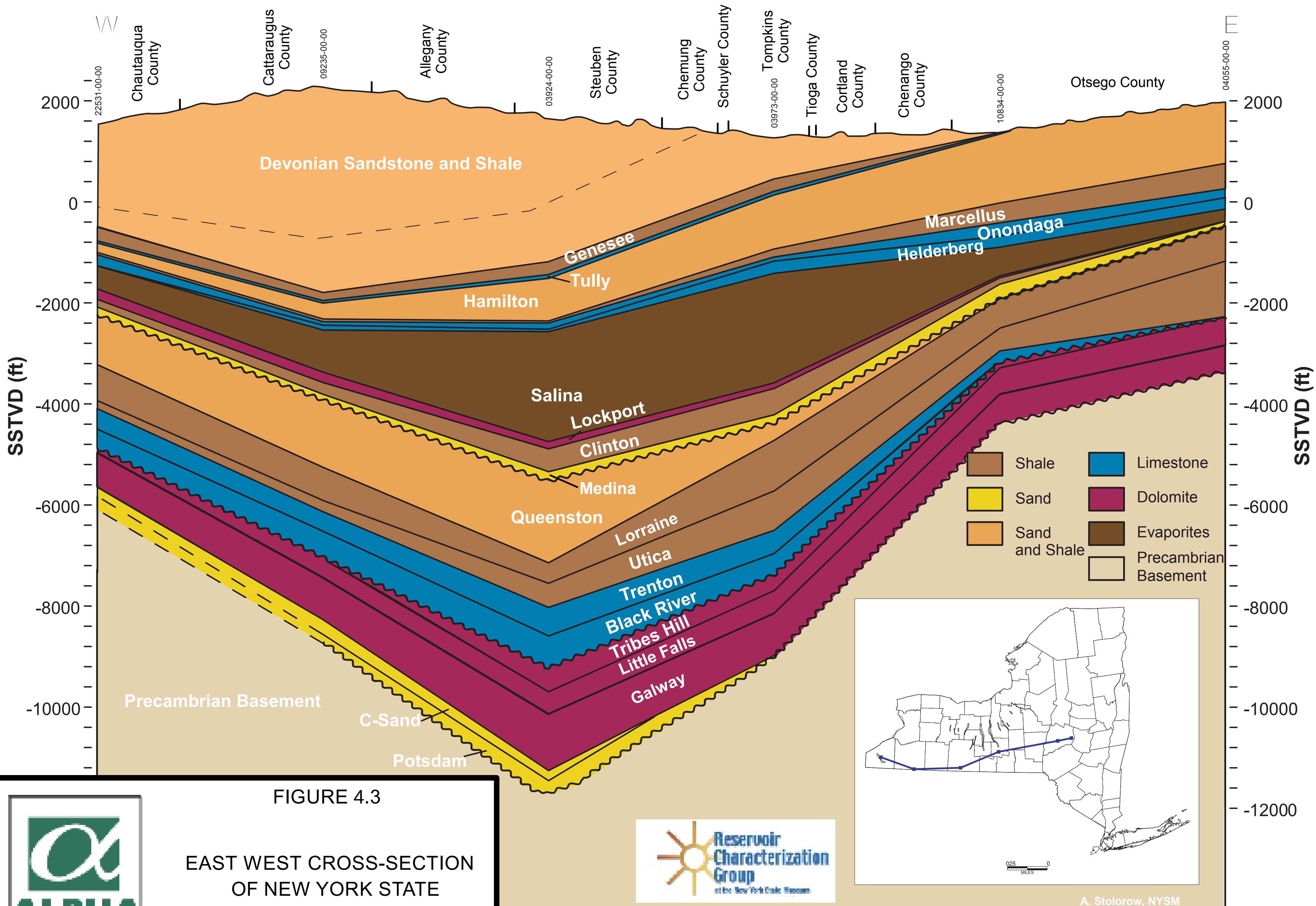
[14] Alpha, 2009

[15] Alpha, 2009

Figure 4.2

Stratigraphic Column of New York; Oil and Gas Producing Horizons
(from D.G. Hill, T.E. Lombardi and J. P. Martin, 2002)

PERIOD		GROUP	UNIT	LITHOLOGY	THICKNESS (feet)	PRODUCTION
PENNSYLVANIAN		Pottsville	Olean	Ss, cgl	75 - 100	
MISSISSIPPIAN		Pocono	Knapp	Ss, cgl	5 - 100	
DEVONIAN	UPPER	Conewango	Riceville	Sh, ss, cgl	70	
		Conneuat	Chadakoin	Sh, ss	700	
		Canadaway	Undiff	Sh, Ss	1,100 - 1,400	Oil, Gas
			Perrysburg-Dunkirk	Sh, ss		Oil, Gas
				Sh, ss		
		West Falls	Java	Sh, ss	365 - 125	
			Nunda	Sh, ss		Oil, Gas
			Rhinestreet	Sh		
		Sonyea	Middlesex	Sh	0 - 400	Gas
		Genesee	Geneseo	Sh	0 - 450	Gas
	?		Tully	Ls	0 - 50	Gas
	MIDDLE	Hamilton	Moscow	Sh	200 - 600	
			Ludlowville	Sh		
			Skaneateles	Sh		
			Marcellus	Sh		Gas
			Onondaga	Ls	30 - 235	Gas, Oil
	LOWER	Tristates	Oriskany	Ss	0 - 40	Gas
		Heldergerg	Manlius	Ls	0 - 10	
			Rondout	Dol		
SILURIAN	UPPER		Akron	Dol	0 - 15	Gas
		Salina	Camillus	Sh, gyp	450 - 1,850	
			Syracuse	Dol, sh, slt		
			Vernon	Sh		Gas
		Lockport	Lockport	Dol	150 - 250	Gas
		Clinton	Rochester	Sh	125	Gas
			Irondequoit	Ls		
	LOWER		Sodus/Oneida	Sh/cgl	75	Gas
			Reynales	Ls		
			Thorold	Ss		
		Medina	Grimsby	Sh, ss	75 - 150	Gas
			Whirlpool	Ss	0 - 25	Gas
ORDOVICIAN	UPPER		Queenston	Sh	1,100 - 1,500	Gas
			Oswego	Ss		Gas
			Lorraine	Sh		
			Utica	Sh	900 - 1000	Gas
	MIDDLE	Trenton-Black River	Trenton	Ls	425 - 625	Gas
			Black River	Ls	225 - 550	Gas
	LOWER	Beekmantown	Tribes Hill-Chuctanunda	Ls	0 - 550	
CAMB.	UPPER		Little Falls	Dol	0 - 350	
			Galway	Dol, ss	575 - 1,350	Gas
			Potsdam	Ss, dol	75 - 500	Gas
PRECAMBRIAN				Gneiss, marble, quartzite		



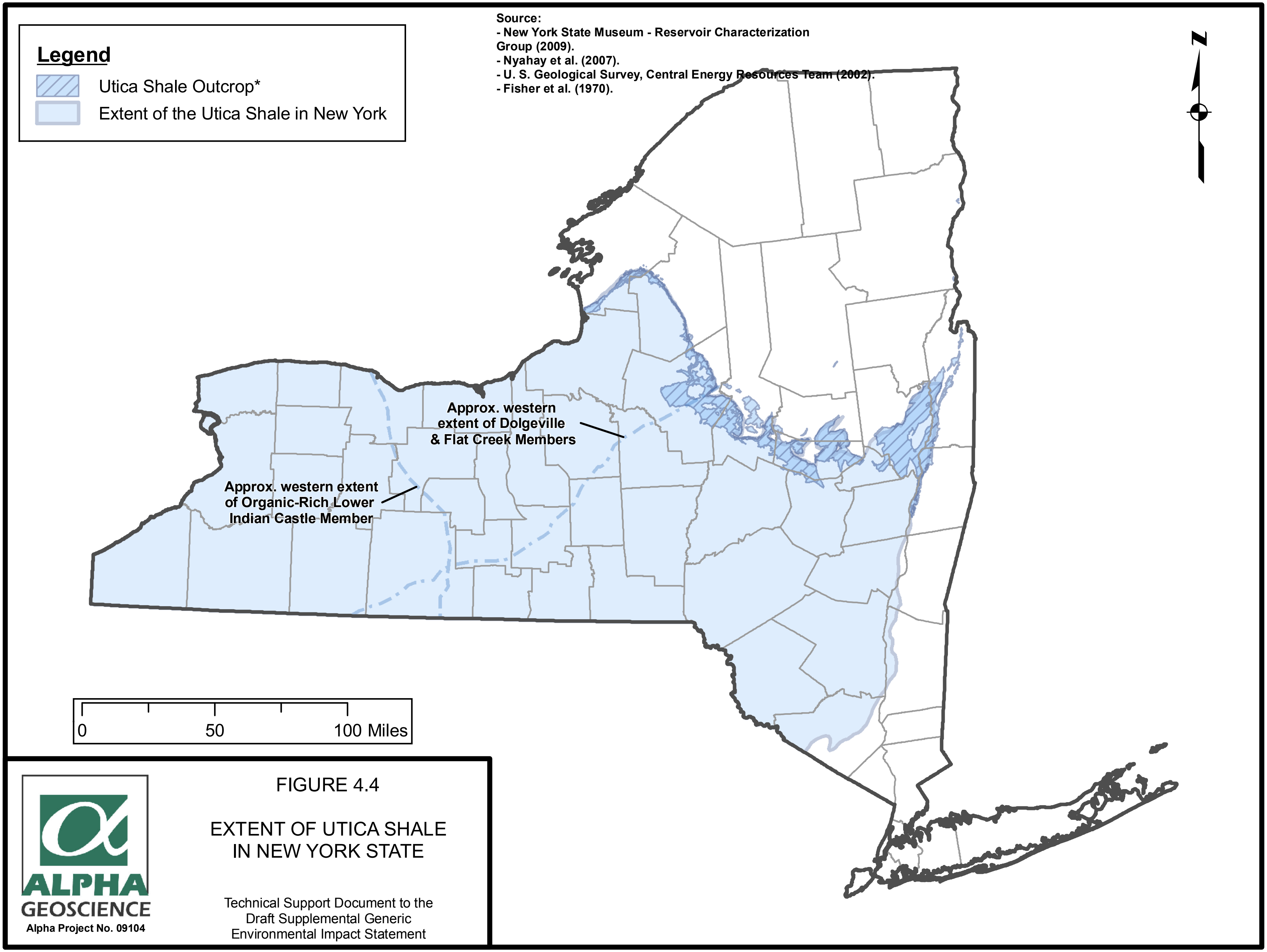
ALPHA GEOSCIENCE

Alpha Project No. 09104

FIGURE 4.3

EAST WEST CROSS-SECTION OF NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement


Legend
Utica Shale Outcrop*
Extent of the Utica Shale in New York
Source:
- New York State Museum - Reservoir Characterization Group (2009).
- Nyahay et al. (2007).
- U. S. Geological Survey, Central Energy Resources Team (2002).
- Fisher et al. (1970).
N
Approx. western extent of Dolgeville & Flat Creek Members
Approx. western extent of Organic-Rich Lower Indian Castle Member
0
50
100 Miles
ALPHA GEOSCIENCE
Alpha Project No. 09104
FIGURE 4.4
EXTENT OF UTICA SHALE IN NEW YORK STATE
Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

4.3.1 Total Organic Carbon

Measurements of TOC in the Utica Shale are sparse. Where reported, TOC has been measured at over 3% by weight.[16] Nyahay et al. (2007) compiled measurements of TOC for core and outcrop samples. TOC in the lower Indian Castle, Flat Creek, and Dolgeville Members generally ranges from 0.5 to 3%. TOC in the upper Indian Castle Member is generally below 0.5%. TOC as high as 3.0% in eastern New York and 15% in Ontario and Quebec were also reported.[17]

The New York State Museum Reservoir Characterization Group evaluated cuttings from the Utica Shale wells in New York State and reported up to 3% TOC.[18] Jarvie et al. (2007) showed that analyses from cutting samples may underestimate TOC by approximately half; therefore, it may be as high as 6%. Figure 4.6 shows the combined total thickness of the organic-rich (greater than 1%, based on cuttings analysis) members of the Utica Shale. As shown on Figure 4.6, the organic-rich Utica Shale ranges from less than 50 feet thick in north-central New York and increases eastward to more than 700 feet thick.

[16] Alpha, 2009

[17] Alpha, 2009

[18] Alpha, 2009

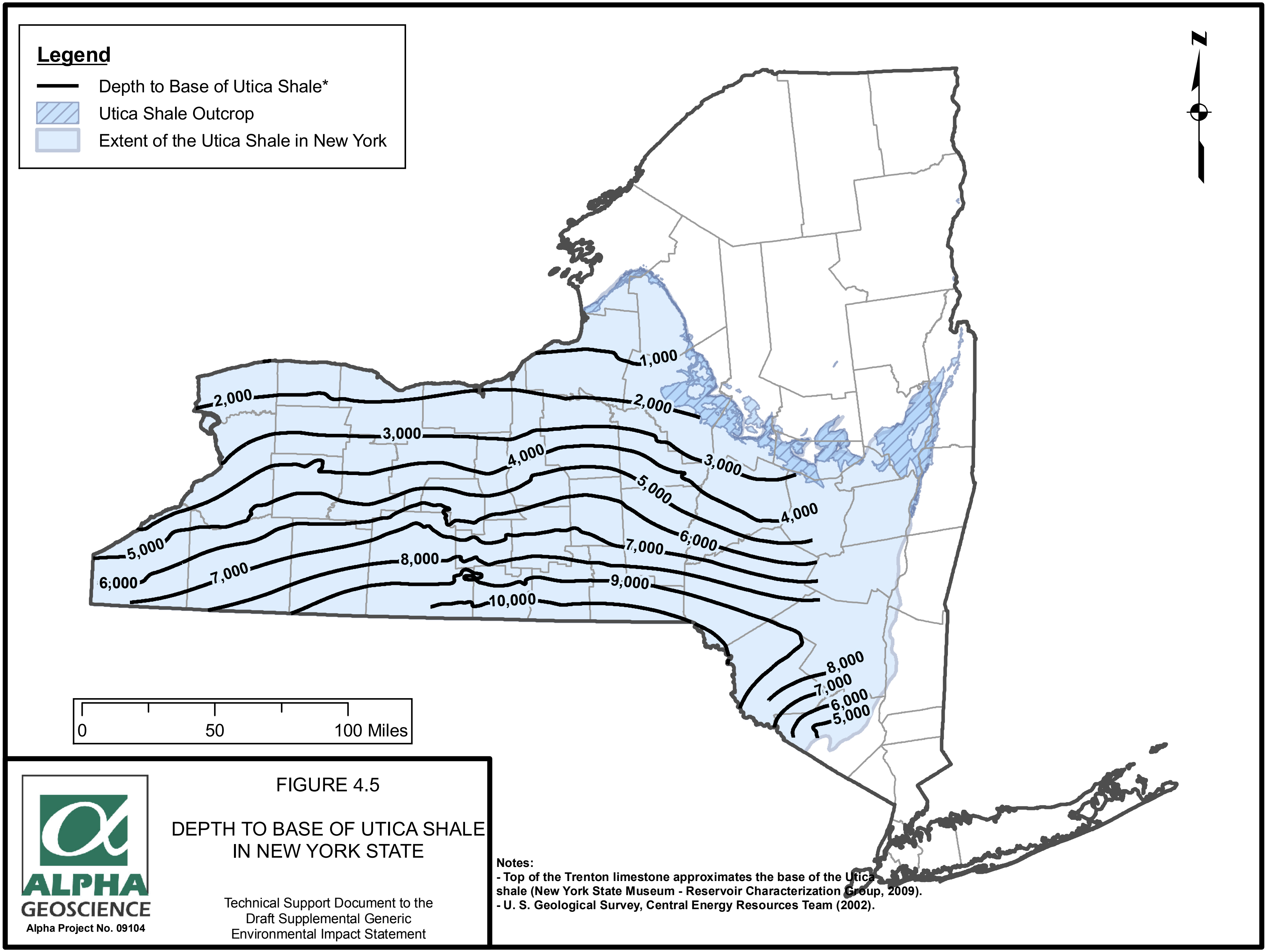


FIGURE 4.5

DEPTH TO BASE OF UTICA SHALE IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

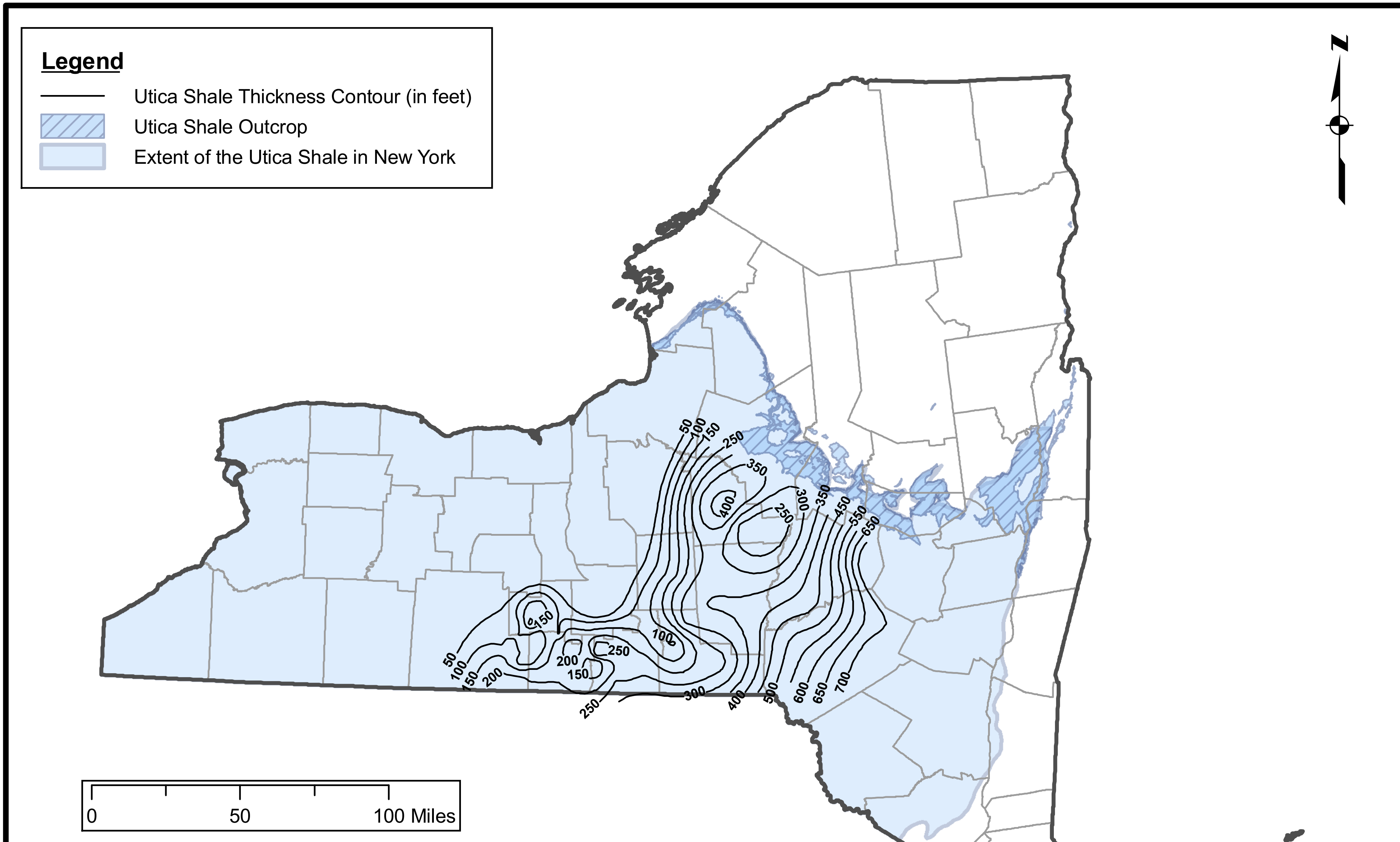


FIGURE 4.6

THICKNESS OF HIGH-ORGANIC UTICA SHALE IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

ALPHA GEOSCIENCE

Alpha Project No. 09104

Note:
- Contours show the combined thickness of the high organic carbon interval (>1% TOC) lower Indian Castle, Dolgeville, Flat Creek members (New York State Museum - Reservoir Characterization Group, 2009).

4.3.2 Thermal Maturity and Fairways

Nyahay, et al. (2007) presented an assessment of gas potential in the Marcellus and Utica shales. The assessment was based on an evaluation of geochemical data from core and outcrop samples using methods applied to other shale gas plays, such as the Barnett Shale in Texas. A gas production "fairway", which is a portion of the shale most likely to produce gas based on the evaluation, was presented. Based on the available, limited data, Nyahay et al. (2007) concluded that most of the Utica Shale is supermature and that the Utica Shale fairway is best outlined by the Flat Creek Member where the TOC and thickness are greatest. This area extends eastward from a northeast-southwest line connecting Montgomery to Steuben Counties (Figure 4.7). The fairway shown on Figure 4.7 correlates approximately with the area where the organic-rich portion of the Utica Shale is greater than 100 feet thick shown on Figure 4.6.[19] The fairway is that portion of the formation that has the potential to produce gas based on specific geologic and geochemical criteria; however, other factors, such as formation depth, make only portions of the fairway favorable for drilling. Operators consider a variety of these factors, besides the extent of the fairway, when making a decision on where to drill for natural gas.

The results of the 2007 evaluation are consistent with an earlier report by Weary et al. (2000) that presented an evaluation of thermal maturity based on patterns of thermal alteration of conodont microfossils across New York State. The data presented show that the thermal maturity of much of the Utica Shale in New York is within the dry natural gas generation and preservation range and generally increases from northwest to southeast.

4.3.3 Potential for Gas Production

The Utica Shale historically has been considered the source rock for the more permeable conventional gas resources. Fresh samples containing residual kerogen and other petroleum residuals reportedly have been ignited and can produce an oily sheen when placed in water.[20] Significant gas shows have been reported while drilling through the Utica Shale in eastern and central New York.[21]

---

[19] Alpha, 2009

[20] Alpha, 2009

[21] Alpha, 2009

No Utica Shale gas production was reported to DEC in 2009. Vertical test wells completed in the Utica in the St. Lawrence Lowlands of Quebec have produced up to one million cubic feet per day (MMcf/d) of natural gas, and horizontal test wells are planned for 2009 (June, 2009).

4.4 Marcellus Formation

The Marcellus Formation is a Middle Devonian-aged member of the Hamilton Group that extends across most of the Appalachian Plateau from New York south to Tennessee. The Marcellus Formation consists of black and dark gray shales, siltstones, and limestones. The Marcellus Formation lies between the Onondaga limestone and the overlying Stafford-Mottville limestones of the Skaneateles Formation[22] and ranges in thickness from less than 25 feet in Cattaraugus County to over 1,800 feet along the Catskill front.[23] The informal name "Marcellus Shale" is used interchangeably with the formal name "Marcellus Formation." The discussion contained herein uses the name Marcellus Shale to refer to the black shale in the lower part of the Hamilton Group.

The Marcellus Shale covers an area of approximately 18,700 square miles in New York (Figure 4.8), is bounded approximately by US Route 20 to the north and interstate 87 and the Hudson River to the east, and extends to the Pennsylvania border. The Marcellus is exposed in outcrops to the north and east and reaches depths of more than 5,000 feet in the southern tier (Figure 4.8).

The Marcellus Shale in New York State consists of three primary members[24]. The oldest (lower-most) member of the Marcellus is the Union Springs Shale which is laterally continuous with the Bakoven Shale in the eastern part of the state. The Union Springs (and Bakoven Shale) are bounded below by the Onondaga and above by the Cherry Valley Limestone in the west and the correlative Stony Hollow Member in the East. The upper-most member of the Marcellus Shale is the Oatka Creek Shale (west) and the correlative Cardiff-Chittenango Shales (east). The members of primary interest with respect to gas production are the Union Springs and lower-most portions

[22] Alpha, 2009

[23] Alpha, 2009

[24] Alpha, 2009

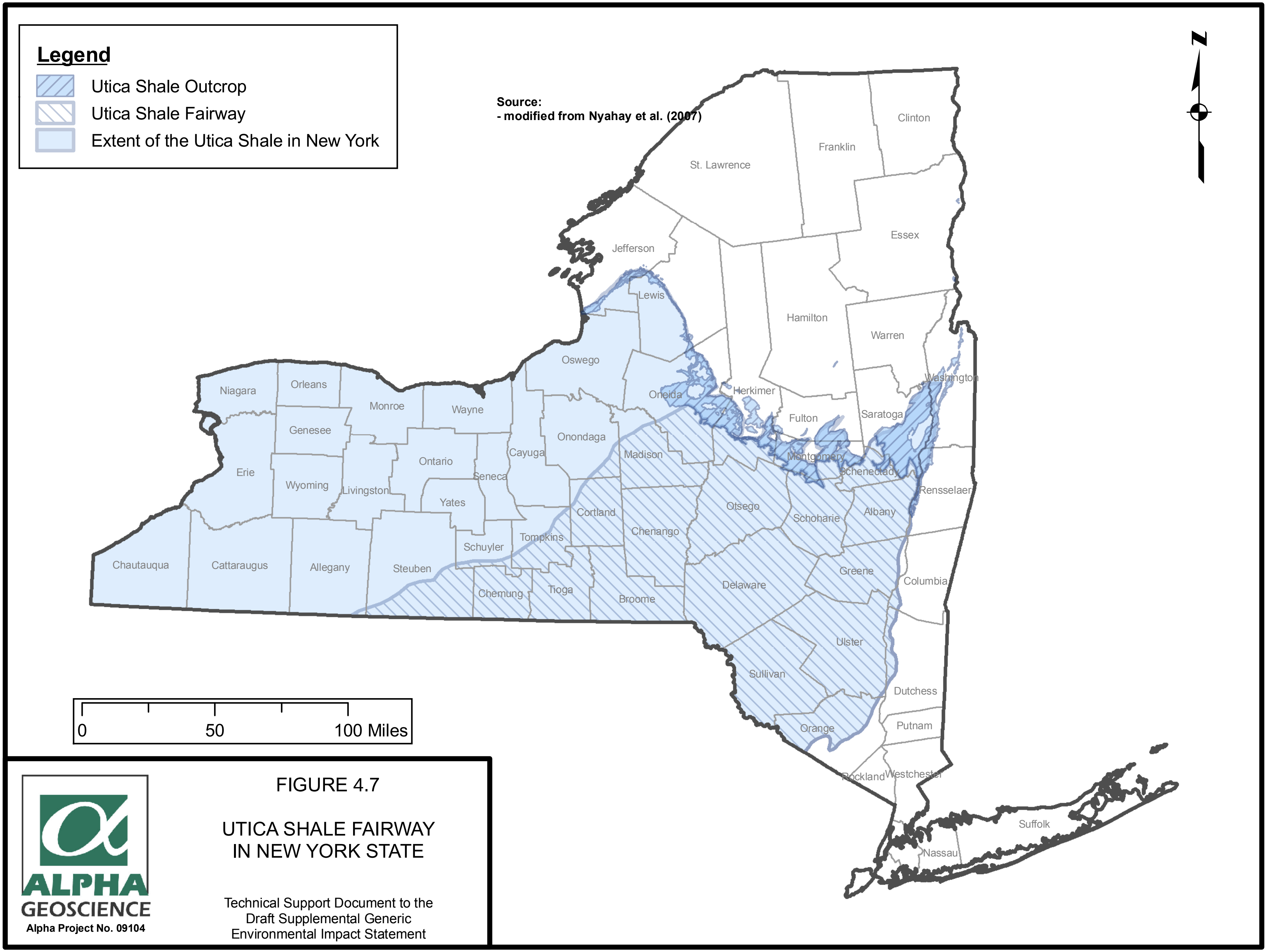


FIGURE 4.7

UTICA SHALE FAIRWAY
IN NEW YORK STATE

Technical Support Document to the
Draft Supplemental Generic
Environmental Impact Statement

of the Oatka Creek Shale.[25] The cumulative thickness of the organic-rich layers ranges from less than 25 feet in western New York to over 300 feet in the east (Figure 4.9).

Gamma ray logs indicate that the Marcellus Shale has a slightly radioactive signature on gamma ray geophysical logs, consistent with typical black shales. Concentrations of uranium ranging from 5 to 100 parts per million have been reported in Devonian gas shales.[26]

4.4.1 Total Organic Carbon

Figure 4.10 shows the aerial distribution of total organic carbon (TOC) in the Marcellus Shale based on the analysis of drill cuttings sample data.[27] TOC generally ranges between 2.5 and 5.5 percent and is greatest in the central portion of the state. Ranges of TOC values in the Marcellus were compiled and reported between 3 to 12%[28] and 1 to 10.1%.[29]

4.4.2 Thermal Maturity and Fairways

Vitrinite reflectance is a measure of the maturity of organic matter in rock with respect to whether it has produced hydrocarbons and is reported in percent reflection (%Ro). Values of 1.5 to 3.0% Ro are considered to correspond to the "gas window," though the upper value of the window can vary depending on formation and kerogen type characteristics.

VanTyne (1993) presented vitrinite reflection data from nine wells in the Marcellus Shale in Western New York. The values ranged from 1.18 % Ro to 1.65 % Ro, with an average of 1.39 %Ro. The vitrinite reflectance values generally increase eastward. Nyahay et al (2007) and Smith & Leone (2009) presented vitrinite reflectance data for the Marcellus Shale in New York (Figure 4.11) based on samples compiled by the New York State Museum Reservoir Characterization Group. The values ranged from less than 1.5 % Ro in western New York to over 3 % Ro in eastern New York.

---

[25] Alpha, 2009

[26] Alpha, 2009

[27] Alpha, 2009

[28] Alpha, 2009

[29] Alpha, 2009

Nyahay et al. (2007) presented an assessment of gas potential in the Marcellus Shale that was based on an evaluation of geochemical data from rock core and outcrop samples using methods applied to other shale gas plays, such as the Barnett Shale in Texas. The gas productive fairway was identified based on the evaluation and represents the portion of the Marcellus Shale most likely to produce gas. The Marcellus fairway is similar to the Utica Shale fairway and is shown on Figure 4.12. The fairway is that portion of the formation that has the potential to produce gas based on specific geologic and geochemical criteria; however, other factors, such as formation depth, make only portions of the fairway favorable for drilling. Operators consider a variety of these factors, besides the extent of the fairway, when making a decision on where to drill for natural gas. Variation in the actual production is evidenced by Marcellus Shale wells outside the fairway that have produced gas and wells within the fairway that have been reported dry.

4.4.3 Potential for Gas Production

Gas has been produced from the Marcellus since 1880 when the first well was completed in the Naples field in Ontario County. The Naples field produced 32 MMcf during its productive life and nearly all shale gas discoveries in New York since then have been in the Marcellus Shale.[30] All gas wells completed in the Marcellus Shale to date are vertical wells.[31]

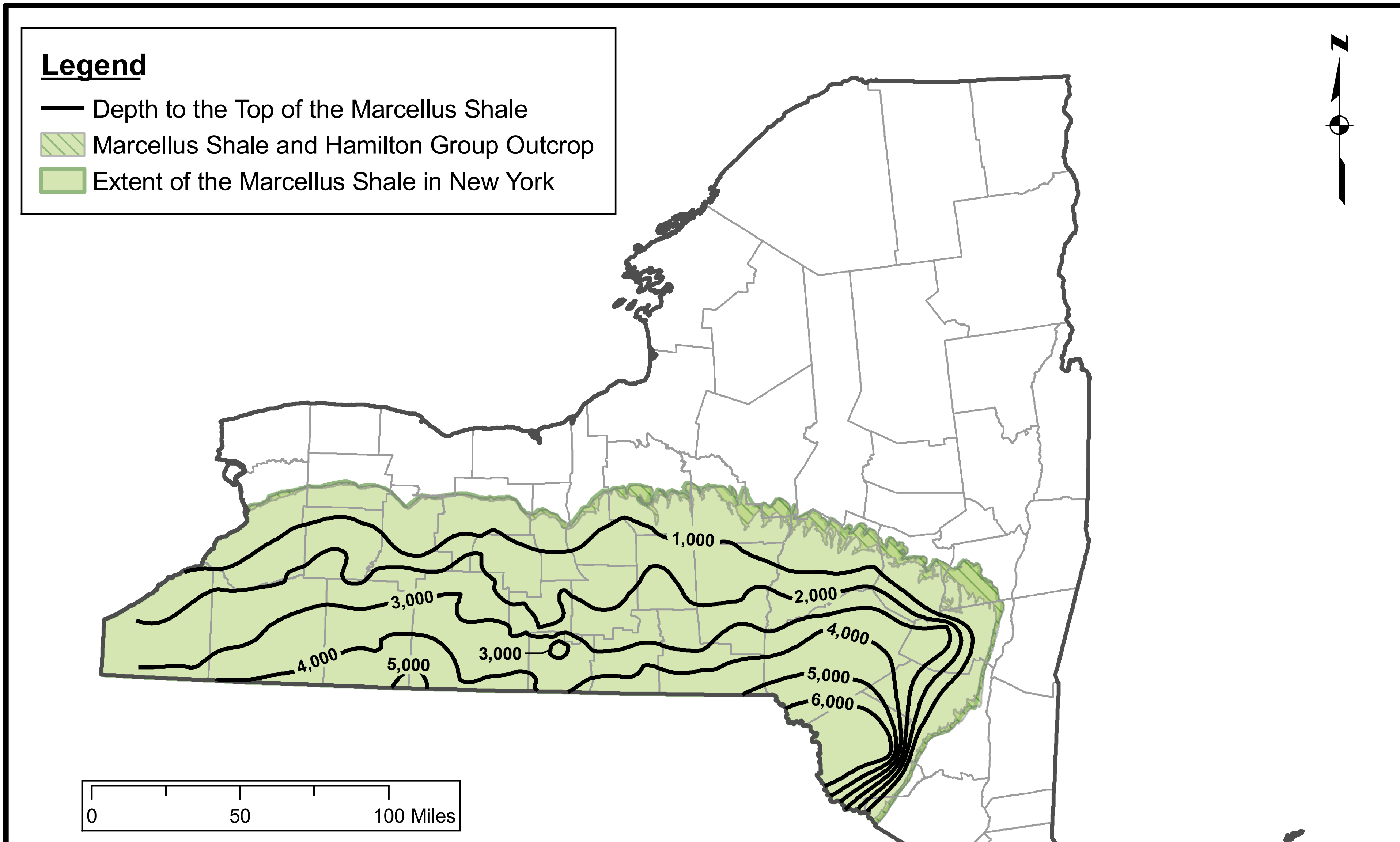
The NYSDEC's summary production database includes reported natural gas production for the years 1967 through 1999. Approximately 544 MMcf of gas was produced from wells completed in the Marcellus Shale during this period.[32] In 2008, the most recent reporting year available, a total of 64.1 MMcf of gas was produced from 15 Marcellus Shale wells in Livingston, Steuben, Schuyler, Chemung, and Allegany Counties.

Volumes of in-place natural gas resources have been estimated for the entire Appalachian Basin. Charpentier et al. (1982) estimated a total in-place resource of 844.2 trillion cubic feet (tcf) in all Devonian shales, which includes the Marcellus Shale. Approximately 164.1 tcf, or 19%, of the total is from Devonian shales in New York State. NYSERDA estimates that approximately 15% of the total Devonian shale gas resource of the Appalachian Basin lies beneath New York State.

[30] Alpha, 2009

[31] Alpha, 2009

[32] Alpha, 2009



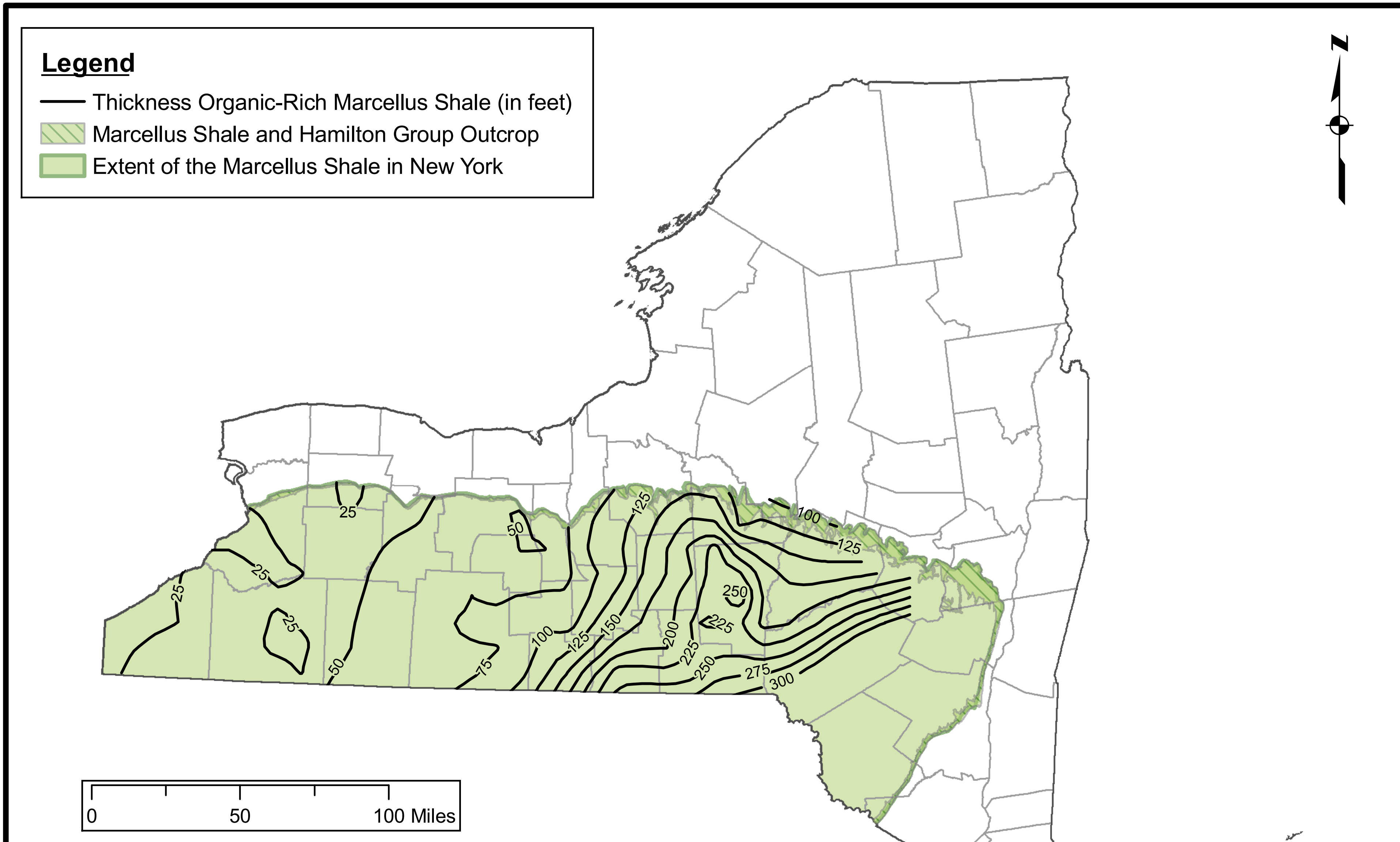
ALPHA GEOSCIENCE
Alpha Project No. 09104

FIGURE 4.8

DEPTH AND EXTENT OF
MARCELLUS SHALE
IN NEW YORK STATE

Technical Support Document to the
Draft Supplemental Generic
Environmental Impact Statement

Source:
- New York State Museum - Reservoir Characterization Group (Leone, 2009).



ALPHA GEOSCIENCE
Alpha Project No. 09104

FIGURE 4.9

MARCELLUS SHALE THICKNESS
IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Notes:
- Source: New York State Museum - Reservoir Characterization Group (Leone, 2009)
- Organic-rich Marcellus includes Union Springs and Oatka Creek Members and lateral equivalents.

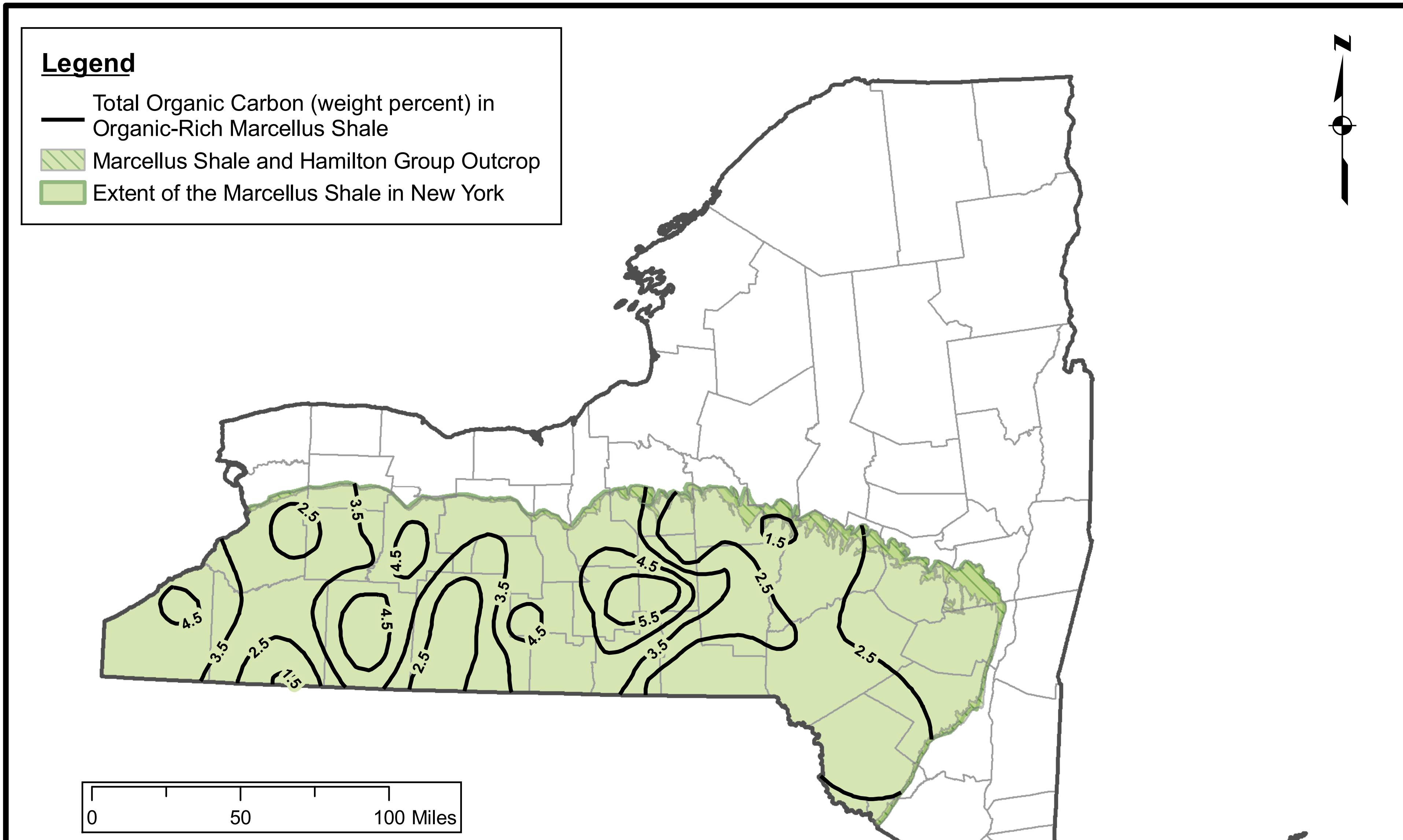


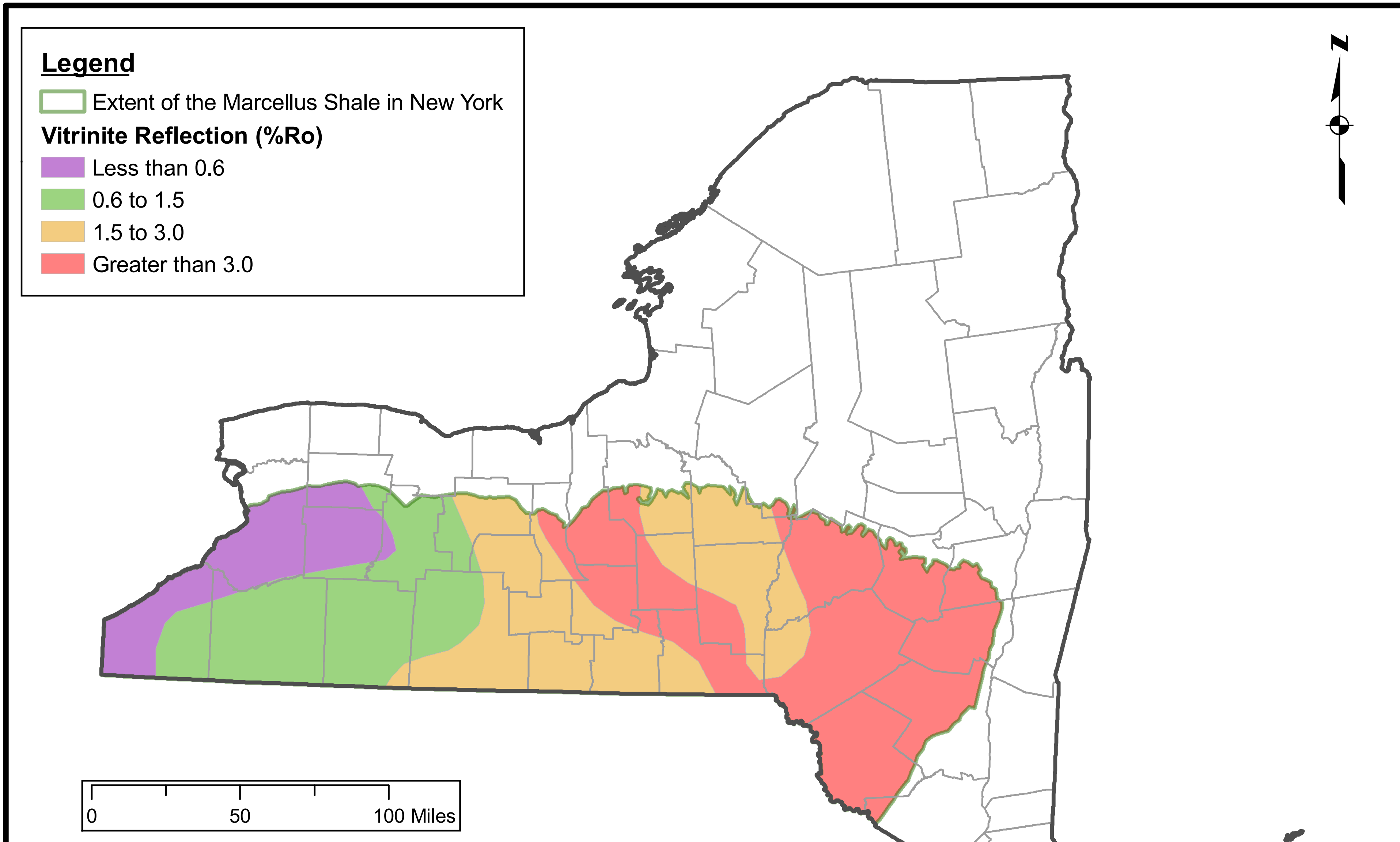
FIGURE 4.10

TOTAL ORGANIC CARBON OF MARCELLUS SHALE IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

ALPHA GEOSCIENCE
Alpha Project No. 09104

Source:
- Modified from New York State Museum - Reservoir Characterization Group (Leone, 2009).



ALPHA GEOSCIENCE

Alpha Project No. 09104

FIGURE 4.11

MARCELLUS SHALE THERMAL MATURITY

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Source:
- Modified from Smith & Leone (2009).

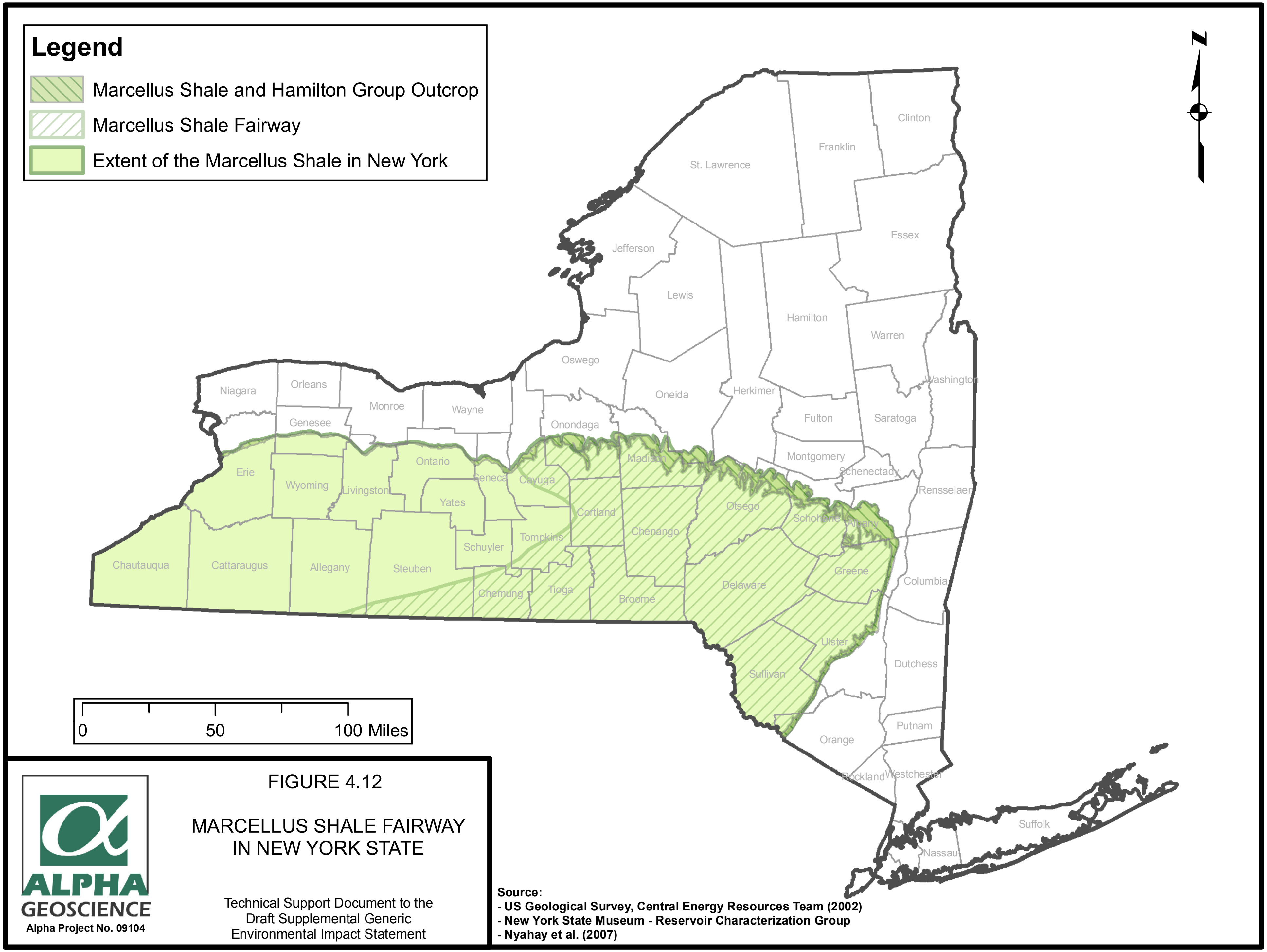


FIGURE 4.12

MARCELLUS SHALE FAIRWAY
IN NEW YORK STATE

Technical Support Document to the
Draft Supplemental Generic
Environmental Impact Statement

Source:
- US Geological Survey, Central Energy Resources Team (2002)
- New York State Museum - Reservoir Characterization Group
- Nyahay et al. (2007)

Engelder and Lash (2008) recently estimated an in-place resource of 500 tcf in the Marcellus shale beneath New York, Pennsylvania, West Virginia, and Maryland. Other natural gas plays, such as the Barnett Shale, typically produce more than 10% of the in-place resource; therefore, the potential resource over time from Marcellus Shale in the four state region including New York is approximately 50 tcf. A 15% to 19% portion of 50 tcf translates to a potential resource of approximately 7.5 to 9.5 tcf of gas over time in the Marcellus Shale in New York State.

4.5 Seismicity in New York State

4.5.1 Background

The term "earthquake" is used to describe any event that is the result of a sudden release of energy in the earth's crust that generates seismic waves. Many earthquakes are too minor to be detected without sensitive equipment. Hydraulic fracturing releases energy during the fracturing process at a level substantially below that of small, naturally occurring, earthquakes. Large earthquakes result in ground shaking and sometimes displacing the ground surface. Earthquakes are caused mainly by movement along geological faults, but also may result from volcanic activity and landslides. An earthquake's point of origin is called its focus or hypocenter. The term epicenter refers to the point at the ground surface directly above the hypocenter.

Induced seismicity refers to seismic events triggered by human activity such as mine blasts, nuclear experiments, and fluid injection, including hydraulic fracturing.[33] Induced seismic waves (seismic refraction and seismic reflection) also are a common tool used in geophysical surveys for geologic exploration. The surveys are used to investigate the subsurface for a wide range of purposes including landfill siting; foundations for roads, bridges, dams and buildings; oil and gas exploration; mineral prospecting; and building foundations. Methods of inducing seismic waves range from manually striking the ground with weight to setting off controlled blasts.

Geologic faults are fractures along which rocks on opposing sides have been displaced relative to each other. The amount of displacement may be small (centimeters) or large (kilometers). Geologic faults are prevalent and typically are active along tectonic plate boundaries. One of the most well known plate boundary faults is the San Andreas fault zone in California. Faults also

[33] Alpha, 2009

occur across the rest of the U.S., including mid-continent and non-plate boundary areas, such as the New Madrid fault zone in the Mississippi Valley, or the Ramapo fault system in southeastern New York and eastern Pennsylvania.

Figure 4.13 shows the locations of faults and other structures that may indicate the presence of buried faults in New York State.[34] There is a high concentration of structures in eastern New York along the Taconic Mountains and the Champlain Valley that resulted from the intense thrusting and continental collisions during the Taconic and Alleghenian orogenies that occurred 350 to 500 million years ago.[35] There also is a high concentration of faults along the Hudson River Valley. More recent faults in northern New York were formed as a result of the uplift of the Adirondack Mountains approximately 5 to 50 million years ago.

4.5.2 Seismic Risk Zones

The USGS Earthquake Hazard Program has produced the National Hazard Maps showing the distribution of earthquake shaking levels that have a certain probability of occurring in the United States. The maps were created by incorporating geologic, geodetic and historic seismic data, and information on earthquake rates and associated ground shaking. These maps are used by others to develop and update building codes and to establish construction requirements for public safety.

New York State is not associated with a major fault along a tectonic boundary like the San Andreas, but seismic events are common in New York. Figure 4.14 shows the seismic hazard map for New York State.[36] The map shows levels of horizontal shaking, in terms of percent of the gravitational acceleration constant (%g) that is associated with a 2 in 100 (2%) probability of occurring during a 50 year period[37]. Much of the Marcellus and Utica Shales underlie portions of the state with the lowest seismic hazard class rating in New York (2 % probability of exceeding 4 to 8 %g in a fifty year period). The areas around New York City, Buffalo, and northern-most

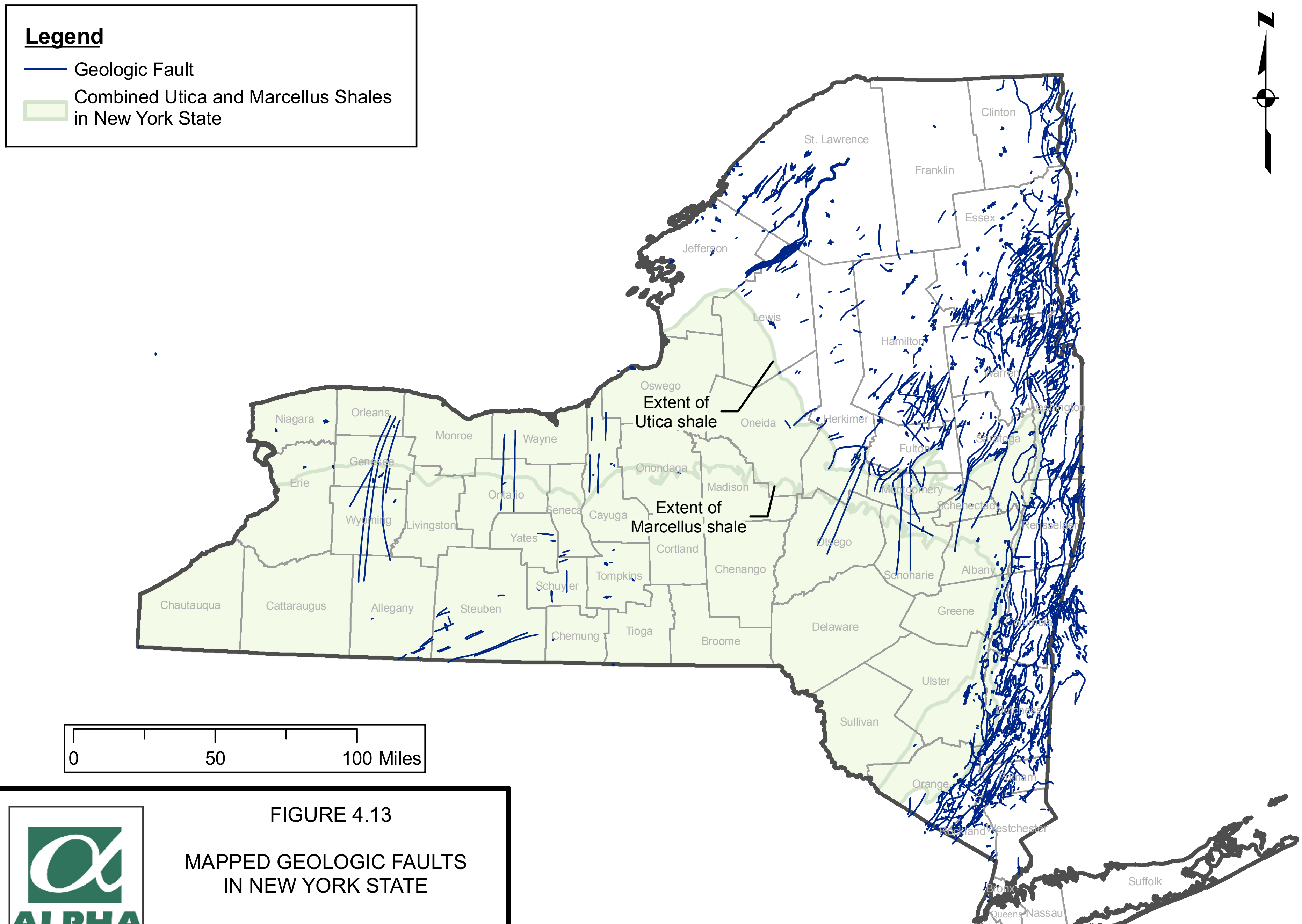
---

[34] Alpha, 2009

[35] Alpha, 2009

[36] Alpha, 2009

[37] Alpha, 2009



ALPHA GEOSCIENCE

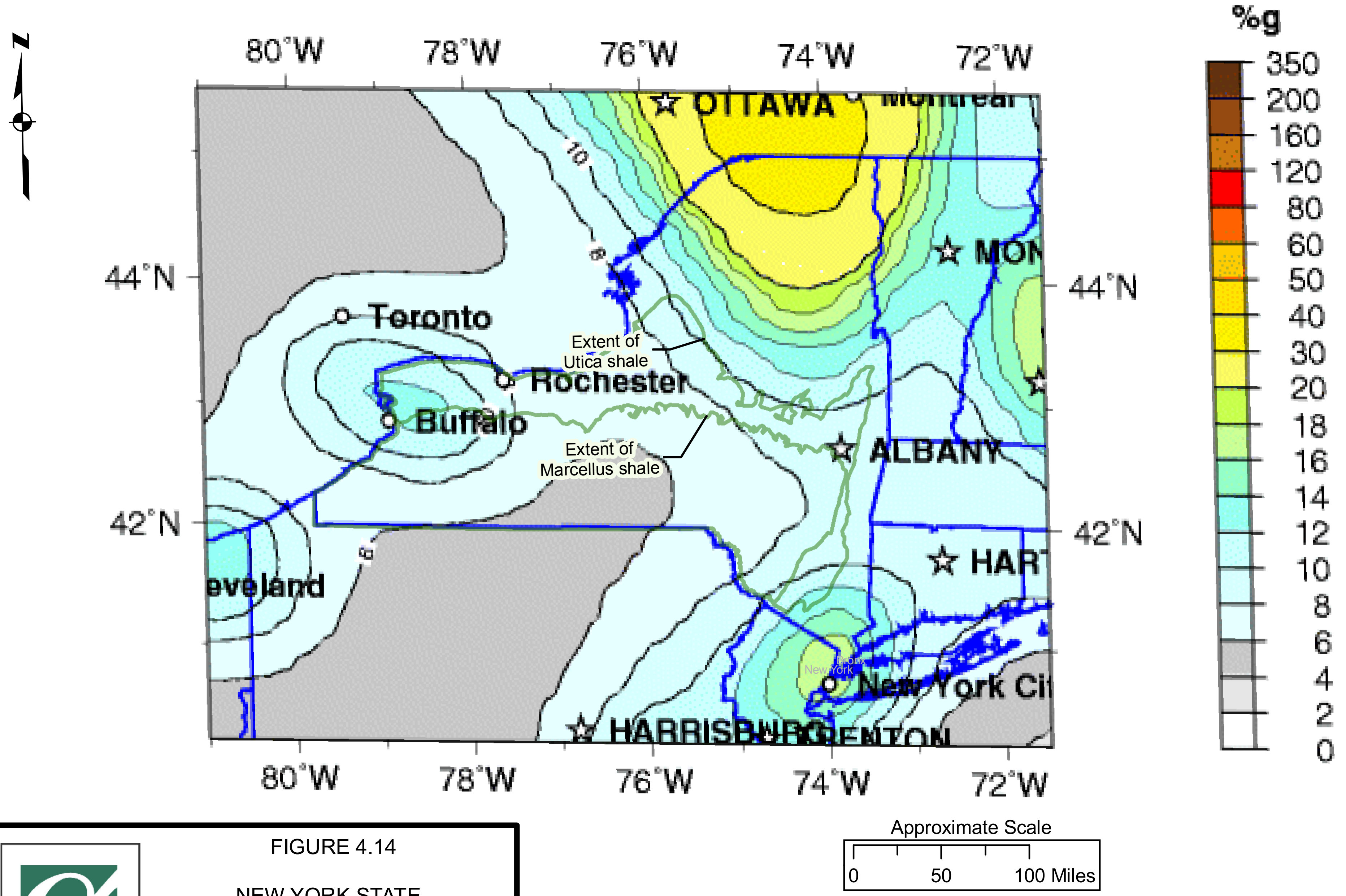
Alpha Project No. 09104

FIGURE 4.13

MAPPED GEOLOGIC FAULTS IN NEW YORK STATE

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Note:
- Geologic fault features shown were complied by Isachsen and McKendree (1977) and exclude brittle structures identified as drillholes, topographic, and tonal linear features.



ALPHA GEOSCIENCE

Alpha Project No. 09104

FIGURE 4.14

NEW YORK STATE
SEISMIC HAZARD MAP

Technical Support Document to the
Draft Supplemental Generic
Environmental Impact Statement

Notes:
- Map shows peak acceleration (%g) with 2% probability of exceedence in 50 years.
- Source - USGS National Seismic Hazard Maps (2008).

New York have a moderate to high seismic hazard class ratings (2% probability of exceeding 12 to 40 %g in a fifty year period).

4.5.3 Seismic Damage – Modified Mercalli Intensity Scale

There are several scales by which the magnitude and the intensity of a seismic event are reported. The Richter magnitude scale was developed in 1935 to measure of the amount of energy released during an earthquake. The moment magnitude scale (MMS) was developed in the 1970s to address shortcomings of the Richter scale, which does not accurately calculate the magnitude of earthquakes that are large (greater than 7) or distant (measured at a distance greater than 250 miles away). Both scales report approximately the same magnitude for earthquakes

less than a magnitude of 7 and both scales are logarithmic-based; therefore, an increase of one magnitude unit corresponds to a 1,000-fold increase in the amount of energy released.

The MMS measures the size of a seismic event based on the amount of energy released. Moment is a representative measure of seismic strength for all sizes of events and is independent of recording instrumentation or location. Unlike the Richter scale, the MMS has no limits to the possible measurable magnitudes, and the MMS relates the moments to the Richter scale for continuity. The MMS also can represent microseisms (very small seismicity) with negative numbers.

The Modified Mercalli (MM) Intensity Scale was developed in 1931 to report the intensity of an earthquake. The Mercalli scale is an arbitrary ranking based on observed effects and not on a mathematical formula. This scale uses a series of 12 increasing levels of intensity that range from imperceptible shaking to catastrophic destruction, as summarized on Table 4.1. Table 4.1 compares the MM intensity scale to magnitudes of the MMS, based on typical events as measured near the epicenter of a seismic event. There is no direct conversion between the intensity and magnitude scales because earthquakes of similar magnitudes can cause varying levels of observed intensities depending on factors such location, rock type, and depth.

4.5.4 Seismic Events

Table 4.2 summarizes the recorded seismic events in New York State by county between December 1970 and July 2009.[38] There were a total of 813 seismic events recorded in New York State during that period. The magnitudes of 24 of the 813 events were equal to or greater than 3.0. Magnitude 3 or lower earthquakes are mostly imperceptible and are usually detectable only with sensitive equipment. The largest seismic event during the period 1970 through 2009 is a 5.3 magnitude earthquake that occurred on April 20, 2002, near Plattsburg, Clinton County.[39] Damaging earthquakes have been recorded since Europeans settled New York in the 1600s. The largest earthquake ever measured and recorded in New York State was a magnitude 5.8 event that occurred on September 5, 1944, near Massena, New York.[40]

---

[38] Alpha, 2009

[39] Alpha, 2009

[40] Alpha, 2009

Table 4.1
Modified Mercalli Intensity Scale

Modified Mercalli Intensity	Description	Effects	Typical Maximum Moment Magnitude
I	Instrumental	Not felt except by a very few under especially favorable conditions.	1.0 to 3.0
II	Feeble	Felt only by a few persons at rest, especially on upper floors of buildings.	3.0 to 3.9
III	Slight	Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a truck. Duration estimated.	
IV	Moderate	Felt indoors by many, outdoors by few during the day. At night, some awakened. Dishes, windows, doors disturbed; walls make cracking sound. Sensation like heavy truck striking building. Standing motor cars rocked noticeably.	4.0 to 4.9
V	Rather Strong	Felt by nearly everyone; many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop.	
VI	Strong	Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.	5.0 to 5.9
VII	Very Strong	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.	
VIII	Destructive	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.	6.0 to 6.9
IX	Ruinous	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.	
X	Disastrous	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.	7.0 and higher
XI	Very Disastrous	Few, if any (masonry) structures remain standing. Bridges destroyed. Rails bent greatly.	
XII	Catastrophic	Damage total. Lines of sight and level are distorted. Objects thrown into the air.	

The above table compares the Modified Mercalli intensity scale and moment magnitude scales that typically observed near the epicenter of a seismic event.

Source: USGS Earthquake Hazard Program (http://earthquake.usgs.gov/learning/topics/mag_vs_int.php)

Table 4.2
Summary of Seismic Events in New York State
December 1970 through July 2009

County	Magnitude					Total
	< 2.0	2.0 to 2.9	3.0 to 3.9	4.0 to 4.9	5.0 to 5.3	
Counties Overlying Utica and Marcellus Shales						
Albany	27	20	3	0	0	50
Allegany	0	0	0	0	0	0
Broome	0	0	0	0	0	0
Cattaraugus	0	0	0	0	0	0
Cayuga	0	0	0	0	0	0
Chautauqua	0	0	0	0	0	0
Chemung	0	0	0	0	0	0
Chenango	0	0	0	0	0	0
Cortland	0	0	0	0	0	0
Delaware	1	2	0	0	0	3
Erie	7	5	0	0	0	12
Genesee	3	5	0	0	0	8
Greene	2	1	0	0	0	3
Livingston	1	5	1	0	0	7
Madison	0	0	0	0	0	0
Montgomery	1	2	0	0	0	3
Niagara	7	3	0	0	0	10
Onondaga	0	0	0	0	0	0
Ontario	1	1	0	0	0	2
Otsego	0	0	0	0	0	0
Schoharie	2	4	0	1	0	7
Schuyler	0	0	0	0	0	0
Seneca	0	0	0	0	0	0
Steuben	2	0	1	0	0	3
Sullivan	0	0	0	0	0	0
Tioga	0	0	0	0	0	0
Tompkins	0	0	0	0	0	0
Wyoming	8	5	0	0	0	13
Yates	1	0	0	0	0	1
Subtotal	*63*	*53*	*5*	*1*	*0*	*122*
Counties Overlying Utica Shale						
Fulton	1	2	1	0	0	4
Herkimer	4	3	0	0	0	7
Jefferson	5	3	0	0	0	8
Lewis	3	0	2	0	0	5
Monroe	1	0	0	0	0	1
Oneida	3	4	0	0	0	7
Orange	14	5	0	0	0	19
Orleans	0	0	0	0	0	0
Oswego	2	0	0	0	0	2
Saratoga	1	2	0	0	0	3
Schenectady	1	1	0	0	0	2
Wayne	0	0	0	0	0	0
Subtotal	*35*	*20*	*3*	*0*	*0*	*58*

Table 4.2
Summary of Seismic Events in New York State
December 1970 through July 2009

County	Magnitude					Total
	< 2.0	2.0 to 2.9	3.0 to 3.9	4.0 to 4.9	5.0 to 5.3	
Counties Not Overlying Utica or Marcellus Shales						
Bronx	0	0	0	0	0	0
Clinton	60	30	5	0	1	96
Columbia	0	0	0	0	0	0
Dutchess	6	4	2	0	0	12
Essex	88	64	4	1	1	158
Franklin	40	19	3	0	0	62
Hamilton	53	10	0	0	0	63
Kings	0	0	0	0	0	0
Nassau	1	0	0	0	0	1
New York	3	2	0	0	0	5
Putnam	4	2	0	0	0	6
Queens	0	0	0	0	0	0
Rensselaer	1	0	0	0	0	1
Richmond	0	0	0	0	0	0
Rockland	15	3	0	0	0	18
St. Lawrence	84	29	0	0	0	113
Suffolk	0	0	0	0	0	0
Ulster	3	0	0	0	0	3
Warren	11	5	1	0	0	17
Washington	1	3	0	0	0	4
Westchester	61	11	1	1	0	74
Subtotal	*431*	*182*	*16*	*2*	*2*	*633*
New York State Total	***529***	***255***	***24***	***3***	***2***	***813***

Notes:
- Seismic events recorded December 13, 1970 through July 28, 2009.
- Lamont-Doherty Cooperative Seismographic Network, 2009

Figure 4.15 shows the distribution of recorded seismic events in New York State. The majority of the events occur in the Adirondack Mountains and along the New York-Quebec border. A total of 180 of the 813 seismic events shown on Table 4.2 and Figure 4.15 during a period of 39 years (1970–2009) occurred in the area of New York that is underlain by the Marcellus and/or the Utica shales. The magnitude of 171 of the 180 events was less than 3.0. The distribution of seismic events on Figure 4.15 is consistent with the distribution of fault structures (Figure 4.13) and the seismic hazard risk map (Figure 4.14).

Some of the seismic events shown on Figure 4.15 are known or suspected to be triggered by human activity. The 3.5 magnitude event recorded on March 12, 1994, in Livingston County is suspected to be the result of the collapse associated with the Retsof salt mine failure in Cuylerville, New York.[41] The 3.2 magnitude event recorded on February 3, 2001, was coincident with, and is suspected to have been triggered by, test injections for brine disposal at the New Avoca Natural Gas Storage (NANGS) facility in Steuben County. The cause of the event likely was the result of an extended period of fluid injection near an existing fault[42] for the purposes of siting a deep injection well. The injection for the NANGS project occurred numerous times with injection periods lasting 6 to 28 days and is substantially different than the short-duration, controlled injection used for hydraulic fracturing.

One additional incident suspected to be related to human activity occurred in late 1971 at Texas Brine Corporation's system of wells used for solution mining of brine near Dale, Wyoming County, New York (i.e., the Dale Brine Field). The well system consisted of a central, high pressure injection well (No. 11) and four peripheral brine recovery wells. The central injection well was hydraulically fractured in July 1971 without incident.

The well system was located in the immediate vicinity of the known, mapped, Clarendon-Linden fault zone which is oriented north-south, and extends south of Lake Ontario in Orleans, Genesee, Wyoming, and the northern end of Allegany Counties, New York. The Clarendon-Linden fault zone is not of the same magnitude, scale, or character as the plate boundary fault systems, but

[41] Alpha, 2009

[42] Alpha, 2009

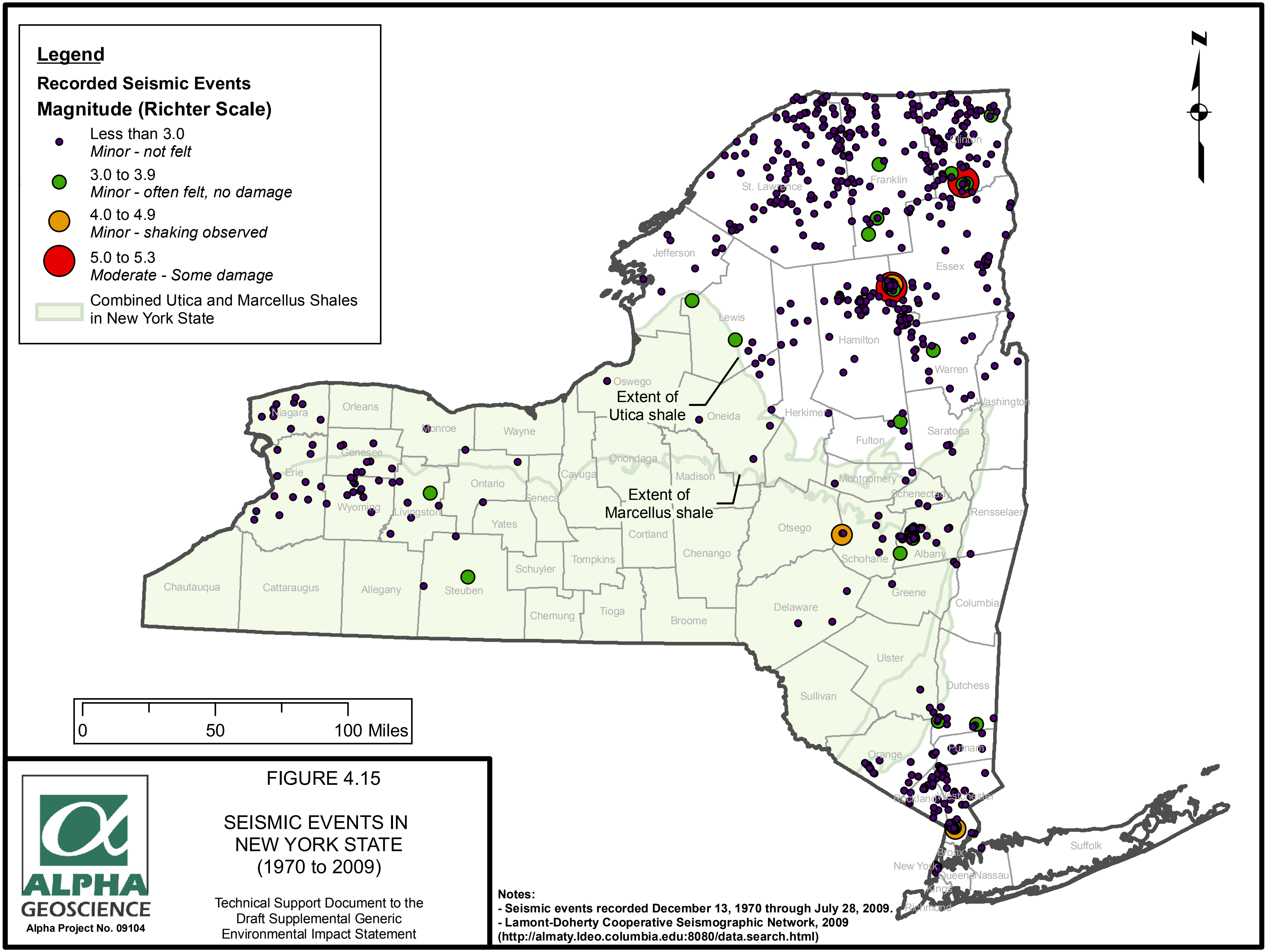


FIGURE 4.15

SEISMIC EVENTS IN NEW YORK STATE (1970 to 2009)

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

nonetheless has been the source of relatively small to moderate quakes in western New York (MCEER, 2009; and Fletcher and Sykes, 1977).

Fluids were injected at well No. 11 from August 3 through October 8, and from October 16 through November 9, 1971. Injections were ceased on November 9, 1971 due to an increase in seismic activity in the area of the injection wells. A decrease in seismic activity occurred when the injections ceased. The tremors attributed to the injections reportedly were felt by residents in the immediate area.

Evaluation of the seismic activity associated with the Dale Brine Field was performed and published by researchers from the Lamont-Doherty Geological Observatory (Fletcher and Sykes, 1977). The evaluation concluded that fluids injected during solution mining activity were able to reach the Clarendon-Linden fault and that the increase of pore fluid pressure along the fault caused an increase in seismic activity. The research states that "the largest earthquake … that appears to be associated with the brine field…" was 1.4 in magnitude. In comparison, the magnitude of the largest natural quake along the Clarendon-Linden fault system through 1977 was magnitude 2.7, measured in 1973. Similar solution mining well operations in later years located further from the fault system than the Dale Brine Field wells did not create an increase in seismic activity.

4.5.5 Monitoring Systems in New York

Seismicity in New York is monitored by both the US Geological Survey (USGS) and the Lamont-Doherty Cooperative Seismographic Network (LCSN). The LCSN is part of the USGS's Advanced National Seismic System (ANSS) which provides current information on seismic events across the country. Other ANSS stations are located in Binghamton and Lake Ozonia, New York. The New York State Museum also operates a seismic monitoring station in the Cultural Education Center in Albany, New York.

As part of the AANS, the LCSN monitors earthquakes that occur primarily in the northeastern United States and coordinates and manages data from 40 seismographic stations in seven states, including Connecticut, Delaware, Maryland, New Jersey, New York, Pennsylvania, and

Vermont.[43] Member organizations that operate LCSN stations include two secondary schools, two environmental research and education centers, three state geological surveys, a museum dedicated to Earth system history, two public places (Central Park, NYC, and Howe Caverns, Cobleskill), three two-year colleges, and 15 four-year universities.[44]

4.6 Naturally Occurring Radioactive Materials (NORM) in Marcellus Shale

As mentioned above, black shale typically contains trace levels of uranium and gamma ray logs indicate that this is true of the Marcellus Shale. The Marcellus Shale formation is known to contain concentrations of naturally occurring radioactive materials (NORM) such as uranium-238 and radium-226 at higher levels than surrounding rock formations. Normal disturbance of NORM-bearing rock formations by activities such as mining or drilling do not generally pose a threat to workers, the general public or the environment. However, activities that have the potential to concentrate NORM need to come under government scrutiny to ensure adequate protection.

Chapter 5 includes radiological information (sampling results) from Marcellus drill cuttings and production brine samples collected in New York and from Marcellus flowback water analyses provided by operators for wells in Pennsylvania and West Virginia. Chapter 6 includes a discussion of potential impacts associated with radioactivity in the Marcellus Shale. Chapter 7 details mitigation measures, including existing regulatory programs, proposed well permit conditions and proposed future data collection and analysis.

---

[43] Alpha, 2009

[44] Alpha, 2009

Chapter 5 NATURAL GAS DEVELOPMENT ACTIVITIES AND HIGH-VOLUME HYDRAULIC FRACTURING

As noted in the GEIS, New York has a long history of natural gas production. The first gas well was drilled in 1821 in Fredonia, and the 40 billion cubic feet ("bcf") of gas produced in 1938 remained the production peak until 2004 when 46.9 bcf were produced. Annual production has exceeded 50 bcf every year since then. Chapters 9 and 10 of the GEIS comprehensively discuss well drilling, completion and production operations, including potential environmental impacts and mitigation measures. The history of hydrocarbon development in New York through 1988 is also covered in the GEIS.

New York counties with actively producing gas wells reported in 2008 were: Allegany, Cattaraugus, Cayuga, Chautauqua, Chemung, Chenango, Erie, Genesee, Livingston, Madison, Niagara, Oneida, Ontario, Oswego, Schuyler, Seneca, Steuben, Tioga, Wayne, Wyoming and Yates. Broome County saw production in 2007, but not in 2008.

5.1 Access Roads and Well Pads

5.1.1 Access Roads

The first step in developing a natural gas well site is to construct the access road and well pad. For environmental review and permitting purposes, the acreage and disturbance associated with the access road is considered part of the project as described by Topical Response #4 in the 1992 Final GEIS. However, instead of one well per access road as was typically the case when the GEIS was prepared, most shale gas development will consist of several wells on a multi-well pad serviced by a single access road. Therefore, in areas developed by horizontal drilling using multi-well pads, fewer access roads as a function of the number of wells will be needed.

Access road construction involves clearing the route and preparing the surface for movement of heavy equipment. Ground surface preparation typically involves placing a layer of crushed stone, gravel or cobbles over geotextile fabric. Sedimentation and erosion control features are also constructed as needed along the access roads and culverts may be placed across ditches at the entrance from the main highway or in low spots along the road.

The size of the access road is dictated by the size of equipment to be transported to the well site, distance of the well pad from an existing road and the route dictated by property access rights and environmental concerns. The route selected may not be the shortest distance to the nearest main road. Routes for access roads may be selected to make use of existing roads on a property and to avoid disturbing environmentally sensitive areas such as protected streams, wetlands, or steep slopes. Property access rights and agreements and traffic restrictions on local roads may also limit the location of access routes. Each 150 feet of a 30-foot wide access road adds about one-tenth of an acre to the total surface acreage disturbance attributed to the well site.

The Department has received applications for 47 horizontal Marcellus Shale wells to be developed in Broome, Chemung, Delaware and Tioga Counties by high-volume hydraulic fracturing. Using this set of applications as a demonstration of the kind of disturbances that can be anticipated in the placement of access roads, the proposed disturbed access road acreage for these sites ranges from 0.1 acres to 2.75 acres, with the access roads ranging from 130 feet to approximately 3,000 feet in length. Widths would range from 20 to 40 feet during the drilling and fracturing phase to 10 to 20 feet during the production phase. During the construction and drilling phase, additional access road width is necessary to accommodate stockpiled topsoil and excavated material along the roadway and to construct sedimentation and erosion control features such as berms, ditches, sediment traps or sumps, or silt fencing along the length of the access road. Pipelines may follow the access road, so additional clearing and disturbance may be conducted during the initial site construction phase to accommodate a future pipeline, adding to the access road width. Some proposals include a 20-foot access road with an additional 10-foot right-of-way. In the situations where pipelines do not follow an access road, sediment and erosion control measures will be followed.

Access roads will also be required for the centralized compression facilities and centralized water storage facilities that are described elsewhere in this document.

Photos 5.1 – 5.4 depict typical wellsite access roads.

5.1.1—Access Roads

Photo 5.1 Access road and erosion/sedimentation controls, Salo 1, Barton, Tioga County NY. Photo taken during drilling phase. This access road is approximately 1,400 feet long. Road width averages 22 feet wide, 28 feet wide at creek crossing (foreground). Width including drainage ditches is approximately 27 feet.
Source: NYS DEC 2007.

Photo 5.2 Nornew, Smyrna Hillbillies #2H, access road, Smyrna, Madison County NY. Photo taken during drilling phase of improved existing private dirt road (approximately 0.8 miles long). Not visible in photo is an additional 0.6 mile of new access road construction. Operator added ditches, drainage, gravel & silt fence to existing dirt road.
The traveled part of the road surface in the picture is 12.5' wide; width including drainage ditches is approximately 27 feet. Portion of the road crossing a protected stream is approximately 20 feet wide. Source: NYS DEC 2008.

Photo 5.3 In-service access road to horizontal Marcellus well in Bradford County, PA. Source: Chesapeake Energy

Photo 5.4 Access road and sedimentation controls, Moss 1, Corning, Steuben County NY. Photo taken during post-drilling phase. Access road at the curb is approximately 50 feet wide, narrowing to 33 feet wide between curb and access gate. The traveled part of the access road ranges between 13 and 19 feet wide. Access road length is approximately 1,100 feet long.
Source: NYS DEC 2004.

5.1.2 Well Pads

The activities associated with the preparation of a well pad are similar for both vertical wells and multi- well pads where horizontal drilling and high volume hydraulic fracturing will be used.[1] Site preparation activities consist primarily of clearing and leveling an area of adequate size and preparing the surface to support movement of heavy equipment. As with access road construction, ground surface preparation typically involves placing a layer of crushed stone, gravel or cobbles over geotextile fabric. Site preparation also includes establishing erosion and sediment control structures around the site, and constructing pits for retention of drilling fluid and, possibly, fresh water.

Depending on site topography, part of a slope may be excavated and the excavated material may be used as fill ("cut and fill" construction) to extend the well pad, providing for a level working area and more room for equipment and onsite storage. The fill banks must be stabilized using appropriate sedimentation and control measures.

The primary difference in well pad preparation for a well where high-volume hydraulic fracturing will be employed versus a well described by the 1992 GEIS is that more land is disturbed on a per-pad basis.[2] A larger well pad is required to accommodate fluid storage and equipment needs associated with the high-volume fracturing operations. In addition, some of the equipment associated with horizontal drilling has a larger surface footprint than the equipment described by the GEIS.

Again using the set of currently pending applications as an example the 47 proposed wells would be drilled on eleven separate well pads, with between two and six wells initially proposed for each pad. Proposed well pad sizes range from 2.2 acres to 5.5 acres during the drilling and fracturing phase of operations, and from 0.5 to 2 acres after partial reclamation during the production phase. Based on operators' responses to the Department's information requests and current activity in the northern tier of Pennsylvania, an average multi-well pad is likely to be between four and five acres in size during the drilling and fracturing phase, with well pads of

---

[1] Alpha, 2009. p. 6-6.

[2] Alpha

over five acres possible. Average production pad size, after partial reclamation, is likely to average between 1 and 3 acres.

The well pad sizes discussed above are consistent with published information regarding drilling operations in other shale formations, as researched by ICF International for NYSERDA.[3] For example, in an Environmental Assessment published for the Hornbuckle Field Horizontal Drilling Program (Wyoming), the well pad size required for drilling and completion operations is estimated at approximately 460 feet by 340 feet, or about 3.6 acres. This estimate does not include areas disturbed due to access road construction. A study of horizontal gas well sites constructed by SEECO, Inc. in the Fayetteville Shale reports that the operator generally clears 300 feet by 250 feet, or 1.72 acres, for its pad and reserve pits. Fayetteville Shale sites may be as large as 500 feet by 500 feet, or 5.7 acres.

Ultimately, as reported to NYSERDA by ICF International, pad size is determined by site topography, number of wells and pattern layout, with consideration given to the ability to stage, move and locate needed drilling and hydraulic fracturing equipment. Location and design of pits, impoundments, tanks, hydraulic fracturing equipment, reduced emission completion equipment, dehydrators and production equipment such as separators, brine tanks and associated control monitoring, as well as office and vehicle parking requirements, can increase square footage. Mandated surface restrictions and setbacks may also impose additional acreage requirements. On the other hand, availability and access to offsite, centralized dehydrators, compressor stations and impoundments may reduce acreage requirements for individual well pads. [4]

Photos 5.5 – 5.7 depict typical Marcellus well pads, and figure 5.1 is a schematic representation of a typical drilling site.

5.1.3 Well Pad Density

5.1.3.1 Historic Well Density

Well owners reported 6,676 producing natural gas wells in New York in 2008, more than half ofwhich are in Chautauqua County. With 1,056 square miles of land in Chautauqua

[3] ICF Subtask 2 Report, p. 4.

[4] ICF Subtask 2 report, pp. 4-5.

5.1.2 Typical Well Pads

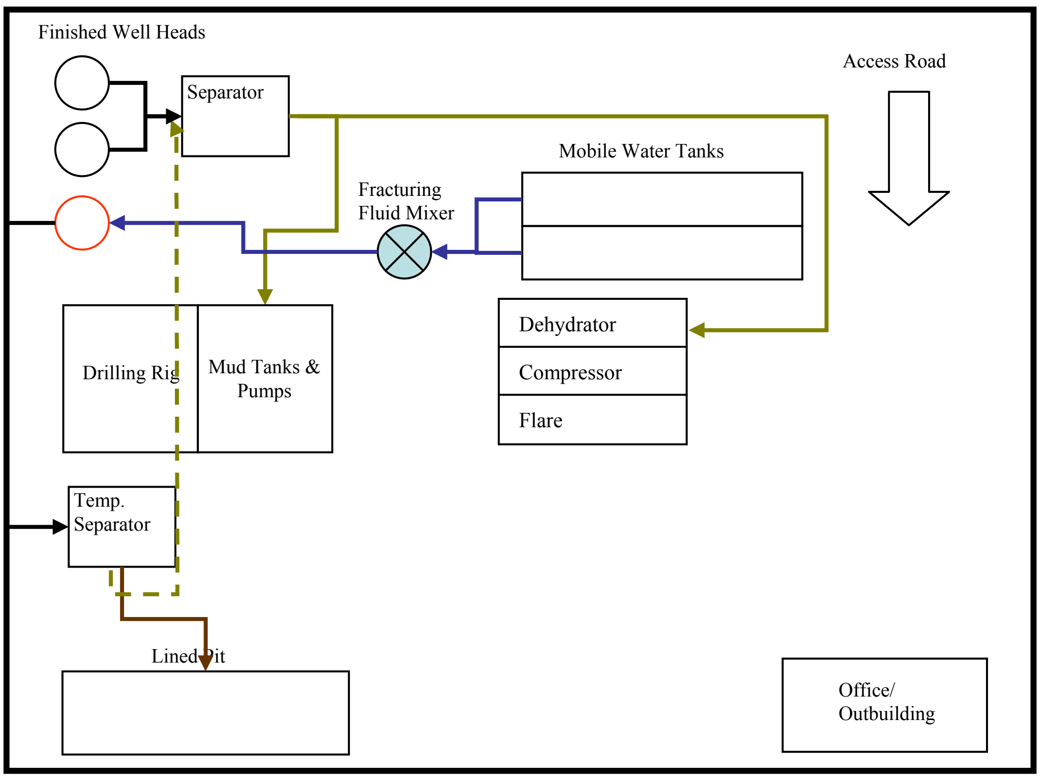
Photo 5.5 Chesapeake Energy Marcellus well drilling, Bradford County PA
Source: Chesapeake Energy

Photo 5.6 Hydraulic fracturing operation, horizontal Marcellus well, Upshur County, WV. Source: Chesapeake Energy, 2008

Photo 5.7 Hydraulic fracturing operation, horizontal Marcellus well, Bradford County, PA
Source: Chesapeake Energy, 2008

County, 3,456 reported producing wells equates to at least three producing wells per square mile. For the most part, these wells are at separate surface locations. Actual drilled density where the resource has been developed is somewhat greater than that, because not every well drilled is currently producing and some areas are not drilled. The Department issued 5,374 permits to drill in Chautauqua County between 1962 and 2008, or five permits per square mile. Of those permits, 63% or 3,396 were issued during a 10-year period between 1975 and 1984, for an average rate of 340 permits per year in a single county. Again, most of these wells were drilled at separate surface locations,

Figure 5-1 - Well Pad Schematic



Not to scale (As reported to NYSERDA by ICF International, derived from Argonne National Laboratory: EVS-Trip Report for Field Visit to Fayetteville Shale Gas Wells, plus expert judgment) each with its own access road and attendant disturbance. Although the number of wells is lower, parts of Seneca and Cayuga County have also been densely drilled. Many areas in all three counties – Chautauqua, Seneca and Cayuga – have been developed with "conventional" gas wells on 40-acre spacing (i.e., 16 wells per square mile, at separate surface locations). Therefore, while recognizing that some aspects of shale development activity will be different from what is described in the GEIS, it is worthwhile to note that this pre-1992 drilling rate and site density were part of the experience upon which the GEIS and its findings are based. Photos 5.8 through 5.11 are photos and aerial views of existing well sites in Chautauqua County, provided for informational purposes. As discussed above, well pads where high-volume hydraulic fracturing will be employed will necessarily be larger in order to accommodate the associated equipment. In areas developed by horizontal drilling, well pads will be less densely spaced, reducing the number of access roads and gathering lines needed.

5.1.3.2 Anticipated Well Pad Density

The number of wells and well sites that may exist per square mile is dictated by reservoir geology and productivity, mineral rights distribution, and statutory well spacing requirements set forth in ECL Article 23, Title 5, as amended in 2008. The statute provides three statewide spacing options for shale wells:

Vertical Wells

Statewide spacing for vertical shale wells provides for one well per 40-acre spacing unit.[5] This is the spacing requirement that has historically governed most gas well drilling in the State, and as mentioned above, many square miles of Chautauqua, Seneca and Cayuga counties have been developed on this spacing. One well per 40 acres equates to a density of 16 wells per square mile (i.e., 640 acres). Infill wells, resulting in more than one well per 40 acres, may be drilled upon justification to the Department that they are necessary to efficiently recover gas reserves. Gas well development on 40-acre spacing, with the possibility of infill wells, has been the prevalent gas well development method in New York for many decades. However, as reported by the Ground Water Protection Council,6 economic and technological considerations favor the use of horizontal drilling for shale gas development. As explained below, horizontal drilling

[5] A spacing unit is the geographic area assigned to the well for the purposes of sharing costs and production. ECL §23-0501(2) requires that the applicant control the oil and gas rights for 60% of the acreage in a spacing unit for a permit to be issued. Uncontrolled acreage is addressed through the compulsory integration process set forth in ECL §23-0901(3).

[6] GPWC, 2009a. *Modern Shale Gas Development in the United States, A Primer,* pp. 46-47.

Natural Gas Wells in Chautauqua County

Year Permit Issued	Total
Pre-1962 (before permit program)	315
1962-1979	1,440
1980-1989	1,989
1990-1999	233
2000-2009	426
Grand Total	4,403

Photo 5.8 This map shows the locations of over 4,400 Medina formation natural gas wells in Chautauqua County from the Mineral Resources database. The wells were typically drilled on 40 to 80 acre well spacing, making the distance between wells at least 1/4 mile.

Readers can re-create this map by using the DEC on-line searchable database using County = Chautauqua and exporting the results to a Google Earth KML file.

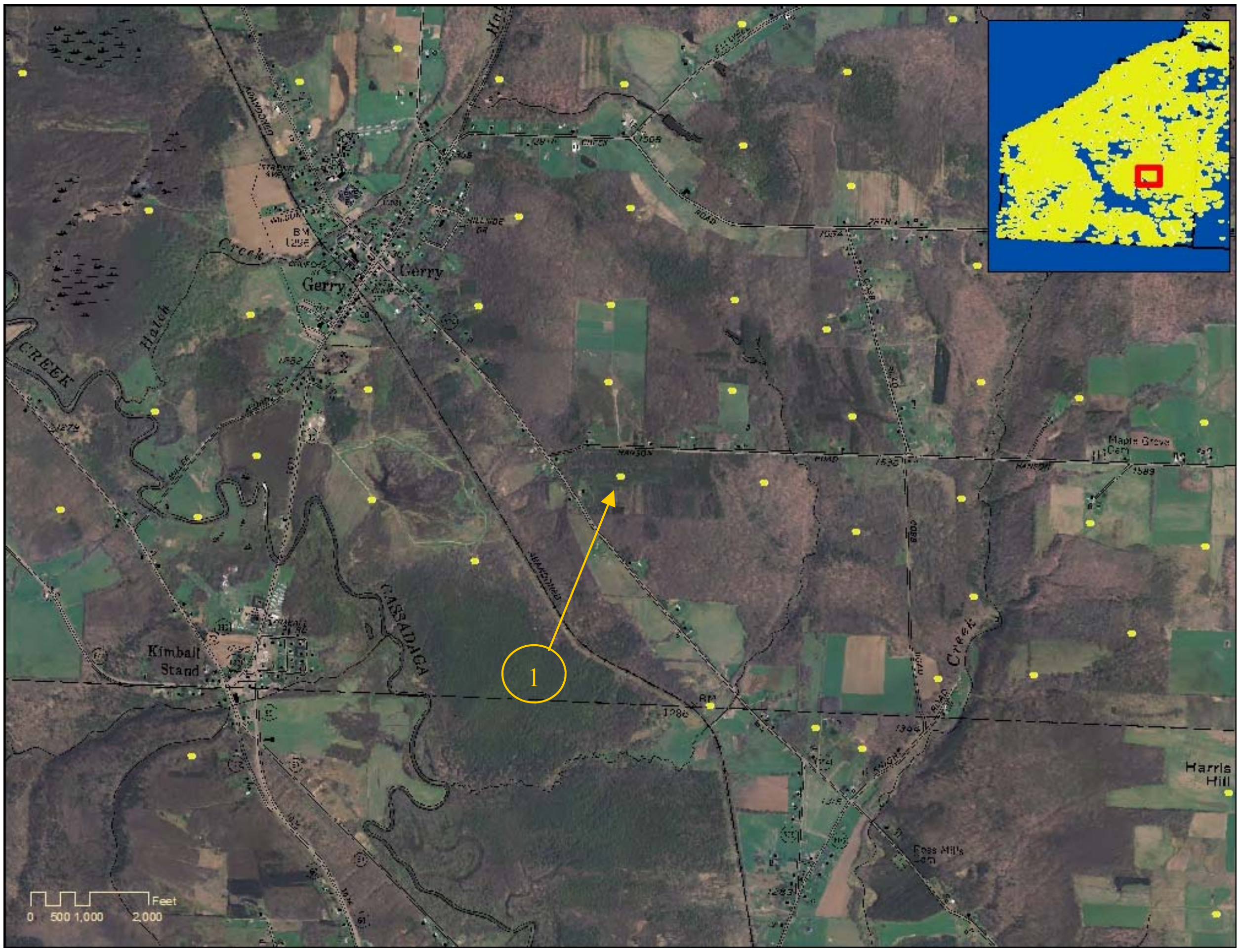


Photo 5.9 The above map shows a portion of the Chautauqua County map, near Gerry. Well #1 (API Hole number 25468) shown in the photo to the right was drilled and completed for production in 2008 to a total depth of 4,095 feet. Of the other 47 Medina gas wells shown above, the nearest is approximately 1,600 feet to the north.

These Medina wells use single well pads. Marcellus multi-well pads will be larger and will have more wellheads and tanks.

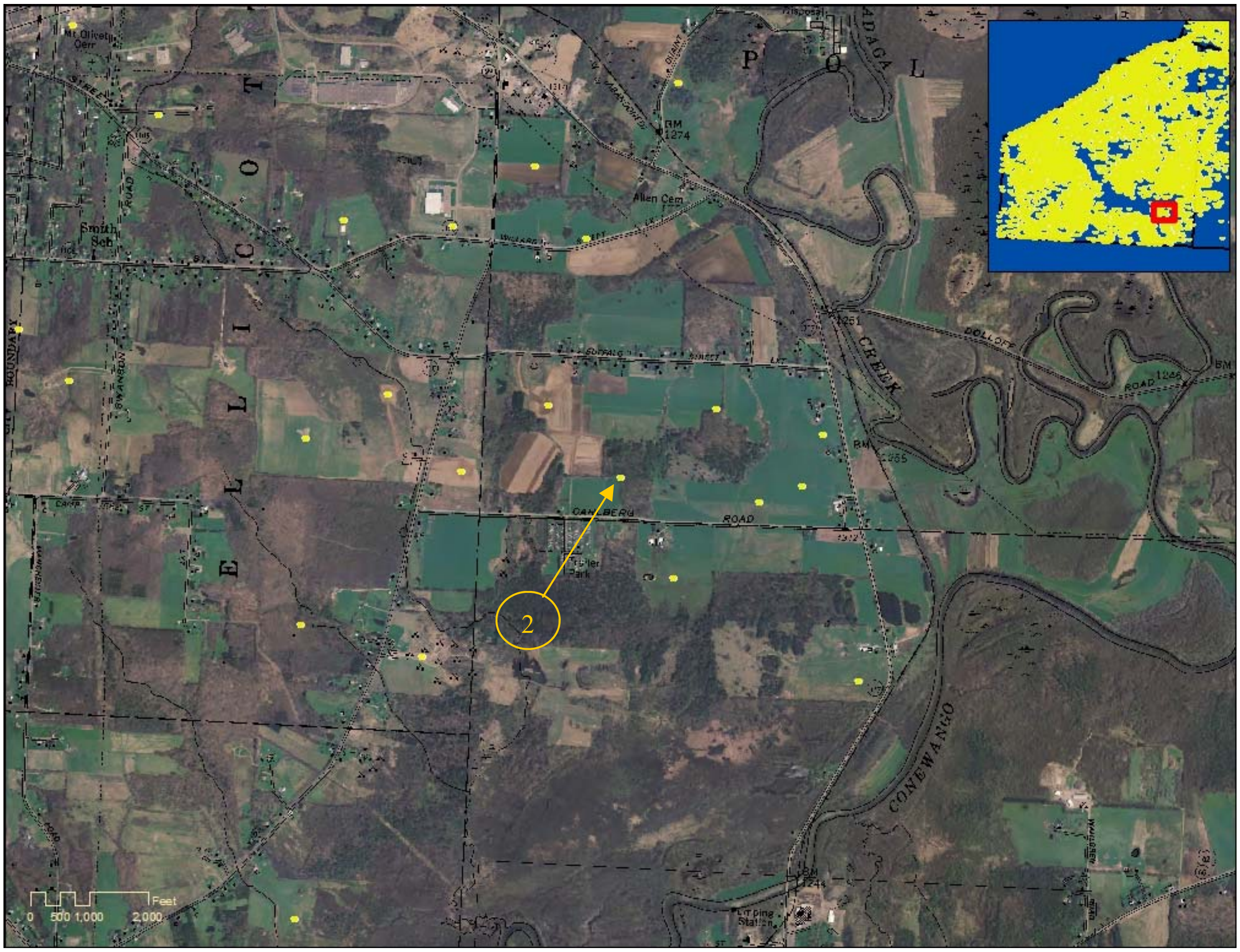


Photo 5.10 This map shows 28 wells in the Town of Poland, Chautauqua County. Well #2 (API Hole number 24422) was drilled in 2006 to a depth of 4,250 feet and completed for production in 2007. The nearest other well is 1,700 feet away.

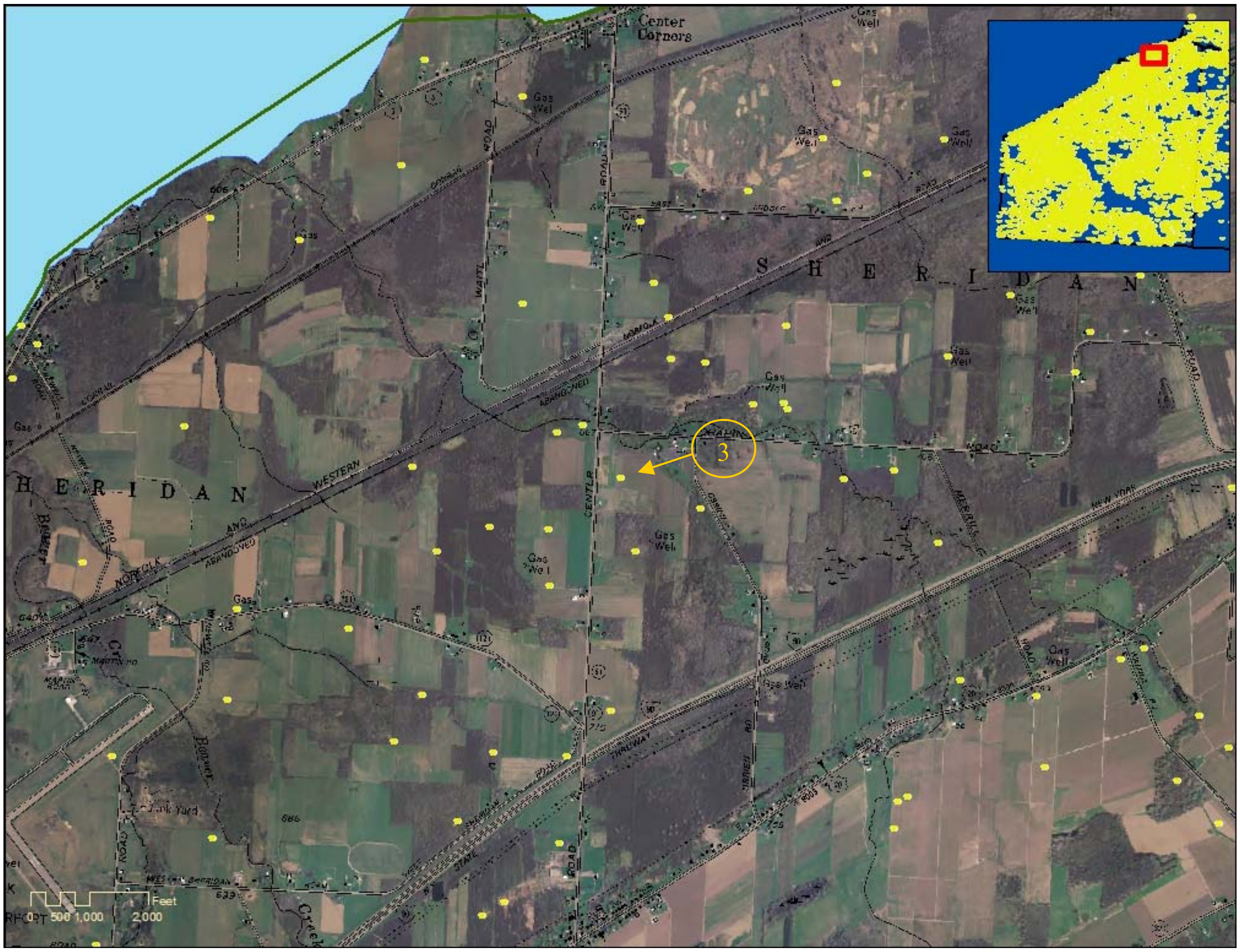


Photo 5.11 Well #3 (API Hole number 16427) in this photo was completed in the Town of Sheridan, Chautauqua County, in 1981 and was drilled to a depth of 2,012 feet.

This map shows 77 wells, with the nearest other producing well 1/4 mile away.

necessarily results in larger spacing units and reduced well pad density. Although legal, vertical drilling, 40-acre well spacing, and 16 well pads per square mile are not expected to be typical for shale gas development in New York using high-volume hydraulic fracturing.

Horizontal Wells in Single-Well Spacing Units

Statewide spacing for horizontal wells where only one well will be drilled at the surface site provides for one well per 40 acres plus the necessary and sufficient acreage to maintain a 330-foot setback between the wellbore in the target formation and the spacing unit boundary. This provision does not provide for horizontal infill wells, so both the width of the spacing unit and the distance within the target formation between wellbores in adjacent spacing units will always be at least 660 feet. Surface locations may be somewhat closer together because of the need to begin building angle in the wellbore about 500 feet above the target formation. However, unless the horizontal length of the wellbores within the target formation is limited to 1,980 feet, the spacing units will exceed 40 acres in size. Although it is possible to drill horizontal wellbores of this length, all information provided to date indicates that, in actual practice, lateral distance drilled will normally exceed 2,000 feet and would most likely be 3,500 feet or more, requiring substantially more than 40 acres. Therefore, the overall density of surface locations would be less than 16 wells per square mile. For example, with 4,000 feet as the length of a horizontal wellbore in the target shale formation, a spacing unit would be 4,660 feet long by 660 feet wide, or about 71 acres in size. Nine, instead of 16, spacing units would fit within a square mile, necessitating nine instead of 16 access roads and nine instead of 16 gas gathering lines.

Horizontal Wells with Multiple Wells Drilled from Common Pads

The third statewide spacing option for shale wells provides, initially, for spacing units of up to 640 acres with all the horizontal wells in the unit drilled from a common well pad. Vertical infill wells may be drilled, with justification, from separate surface locations in the unit. However, a far smaller proportion of vertical infill wells than 15 per 640-acre unit is expected. Therefore, fewer than 16 separate locations within a square mile area will be affected. This method, which also provides the most flexibility to avoid environmentally sensitive locations within the acreage to be developed, is expected to be the most common approach to shale gas development in New York using horizontal drilling and high-volume hydraulic fracturing.

With respect to overall land disturbance, the larger surface area of an individual multi-well pad will be more than offset by the fewer total number of well pads within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells.[7] For example, a spacing of 40 acres per well for vertical shale gas wells would result in 32 - 48 acres of well pad disturbance (2 - 3 acres per well) to develop an area of 640 acres, plus the additional acreage to construct access roads to each of the 16 well pads. A single well pad with 6 to 8 horizontal shale gas wells could access all 640 acres. This translates to a maximum of 4 to 6 acres of well pad disturbance, plus a single access road, compared with 32 acres of well pad disturbance plus access roads to develop the same area using vertical shale gas wells.

Table 5.1 below provides another comparison between the well pad acreage disturbed within a 10-square mile area completely developed by multi-well pad horizontal drilling versus single-well pad vertical drilling.[8]

Table 5-1 - Ten square mile area (i.e., 6,400 acres), completely drilled with horizontal wells in multi-well units or vertical wells in single-well units

Spacing Option	**Multi-Well 640 Acre**	**Single-Well 40 Acre**
Number of Pads	10	160
Total Disturbance - Drilling Phase	50 Acres (5 ac. per pad)	480 Acres (3 ac. per pad)
% Disturbance - Drilling Phase	.78	7.5
Total Disturbance - Production Phase	30 Acres (3 ac. per pad)	240 Acres (1.5 ac. per pad)
% Disturbance - Production Phase	.46	3.75

Variances or Non-Conforming Spacing Units

The statute has always provided for variances from statewide spacing or non-conforming spacing units, with justification, which could result in a greater well density for any of the above options. A variance from statewide spacing or a non-conforming spacing unit requires the Department to issue a well-specific spacing order following public comment and, if necessary, an adjudicatory hearing. Environmental impacts associated with any well to be drilled under a spacing order will

[7] Alpha, 2009. p. 6-2

[8] NTC, 2009, p. 29

continue to be reviewed separately from the spacing variance upon receipt of a specific well permit application.

5.2 Horizontal Drilling

The first horizontal well in New York was drilled in 1989, and in 2008 approximately 10% of the well permit applications received by the Department were for directional or horizontal wells. The predominant use of horizontal drilling associated with natural gas development in New York has been for production from the Black River and Herkimer formations during the past several years. The combination of horizontal drilling and hydraulic fracturing is widely used in other areas of the United States as a means of recovering gas from tight shale formations.

Except for the use of specialized downhole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling, with the same protocols in place for aquifer protection, fluid containment and waste handling. As described below, there are four primary differences between horizontal drilling for shale gas development and the drilling described in the 1992 GEIS. One is that larger rigs may be used for all or part of the drilling, with longer per-well drilling times than were described in the GEIS. The second is that multiple wells will be drilled from each well site (or “well pad”). The third is that drilling mud rather than air may be used while drilling the horizontal portion of the wellbore to lubricate and cool the drill bit and to clean the wellbore. Fourth and finally, the volume of rock cuttings returned to the surface from the target formation will be greater for a horizontal well than for a vertical well.

Vertical drilling depth will vary based on target formation and location within the state. Chapter 5 of the GEIS discusses New York State’s geology with respect to oil and gas production. Chapter 4 of this SGEIS expands upon that discussion, with emphasis on the Marcellus and Utica Shales. Chapter 4 includes maps which show depths and thicknesses related to these two shales.

In general, wells will be drilled vertically to a depth of about 500 feet above the top of a target interval, such as the Union Springs Member of the Marcellus Shale. Drilling may continue with the same rig, or a larger drill rig may be brought onto the location to build angle and drill the horizontal portion of the wellbore. A downhole motor behind the drill bit at the end of the drill pipe is used to accomplish the angled drilling. The drill pipe is also equipped with inclination and azimuth sensors located about 60 feet behind the drill bit to continuously record and report the drill bit's location. The length of the horizontal wellbore may be affected by the operator's lease position or compulsory integration status within the spacing unit, but based on existing applications and current operations in the northern tier of Pennsylvania a typical length may be 4,500 feet.

5.2.1 Drilling Rigs

Wells for shale gas development using high-volume hydraulic fracturing will be drilled with rotary rigs. Rotary rigs are described in the 1992 GEIS, with the typical rotary rigs used in New York at the time characterized as either 40 to 45-foot high "singles" or 70 to 80-foot high "doubles." These rigs can, respectively, hold upright one joint of drill pipe or two connected joints. "Triples," which hold three connected joints of drill pipe upright and are over 100 feet high, were not commonly used in New York State when the GEIS was prepared. However, triples have been more common in New York since 1992 for natural gas storage field drilling and to drill some Trenton-Black River wells.

Operators may use one large rig to drill an entire wellbore from the surface to toe of the horizontal bore, or may use two or three different rigs in sequence. For each well, only one rig is over the hole at a time. At a multi-well site, two rigs may be present on the pad at once, but more than two are unlikely because of logistical and space considerations as described below.

When two rigs are used to drill a well, a smaller rig of similar dimensions to the typical rotary rigs described in the GEIS would first drill the vertical portion of the well. Only the rig used to drill the horizontal portion of the well is likely to be significantly larger than what is described in the GEIS. This rig may be a triple, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Auxiliary equipment includes various tanks (for water, fuel and drilling mud), generators, compressors, solids control equipment (shale shaker, de-silter, de-sander), choke manifold, accumulator, pipe racks and the crew's office space (or "dog house"). Initial work with the smaller rig would typically take up to two weeks, followed by another up to two weeks of work with the larger rig. These estimates include time for casing and cementing the well, and may be extended if drilling is slower than anticipated because of properties of the rock, or if other problems or unexpected delays occur.

When three rigs are used to drill a well, the first rig is used to drill and case the conductor hole. This event generally takes about 8 to12 hours. The dimensions of this rig would be consistent with what is described in the GEIS. The second rig for drilling the remainder of the vertical hole would also be consistent with GEIS descriptions and would again typically be working for up to 14 days, or longer if drilling is slow or problems occur. The third rig, equipped to drill horizontally, would be the only one that might exceed GEIS dimensions, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Work with this rig would take up to 14 days, or longer if drilling is slow or other problems or delays occur.

Appendix 7 includes sample rig specifications provided by Chesapeake Energy. As noted on the specs, fuel storage tanks associated with the larger rigs would hold volumes of 10,000 to 12,000 gallons.

In summary, the rig work for a single horizontal well – including drilling, casing and cementing – would generally last about four to five weeks, subject to extension for slow drilling or other unexpected problems or delays. A 150-foot tall, large-footprint rotary rig may be used for the entire duration or only for the actual horizontal drilling. In the latter case, smaller, GEIS-consistent rigs would be used to drill the vertical portion of the wellbore. The rig and its associated auxiliary equipment would move off the well before fracturing operations commence.

Photos 5.12 – 5.15 are photographs of drilling rigs.

5.2.2 Drill Rigs

Photo 5.12 Double. Union Drilling Rig 54, Olsen 1B, Town of Fenton, Broome County NY. Credit: NYS DEC 2005.

Photo 5.13 Double. Union Drilling Rig 48. Trenton-Black River well, Salo 1, Town of Barton, Tioga County NY. Source: NYS DEC 2008.

Photo 5.14 Triple. Precision Drilling Rig 26. Ruger 1 well,
Horseheads, Chemung County. Credit: NYS DEC 2009.

Photo 5.15 Top Drive Single. Barber and DeLine rig, Sheckells 1, Town of Cherry Valley, Otsego County.
Credit: NYS DEC 2007.

5.2.2 Multi-Well Pad Development

Horizontal drilling from multi-well pads is the common development method employed to develop Marcellus Shale reserves in the northern tier of Pennsylvania and is expected to be common in New York as well. To prevent operators in New York from holding acreage within large spacing units without fully developing the acreage, the Environmental Conservation Law requires that all horizontal wells in a multi-well shale unit be drilled within three years of the date the first well in the unit commences drilling.[9]

As described above, the space required for hydraulic fracturing operations for a multi-well pad is dictated by a number of factors but is expected to most commonly range between four and five acres. The well pad is typically centered in the spacing unit, with surface locations generally about 12 to 20 feet apart. Within the target formation, evenly spaced parallel horizontal bores are drilled in opposite directions. Up to 16 surface locations, but more commonly six or eight, would be arranged in two parallel rows. When fully developed, the resultant horizontal well pattern underground would resemble two back-to-back pitchforks. [Figure 5.2]

[9] ECL §23-0501

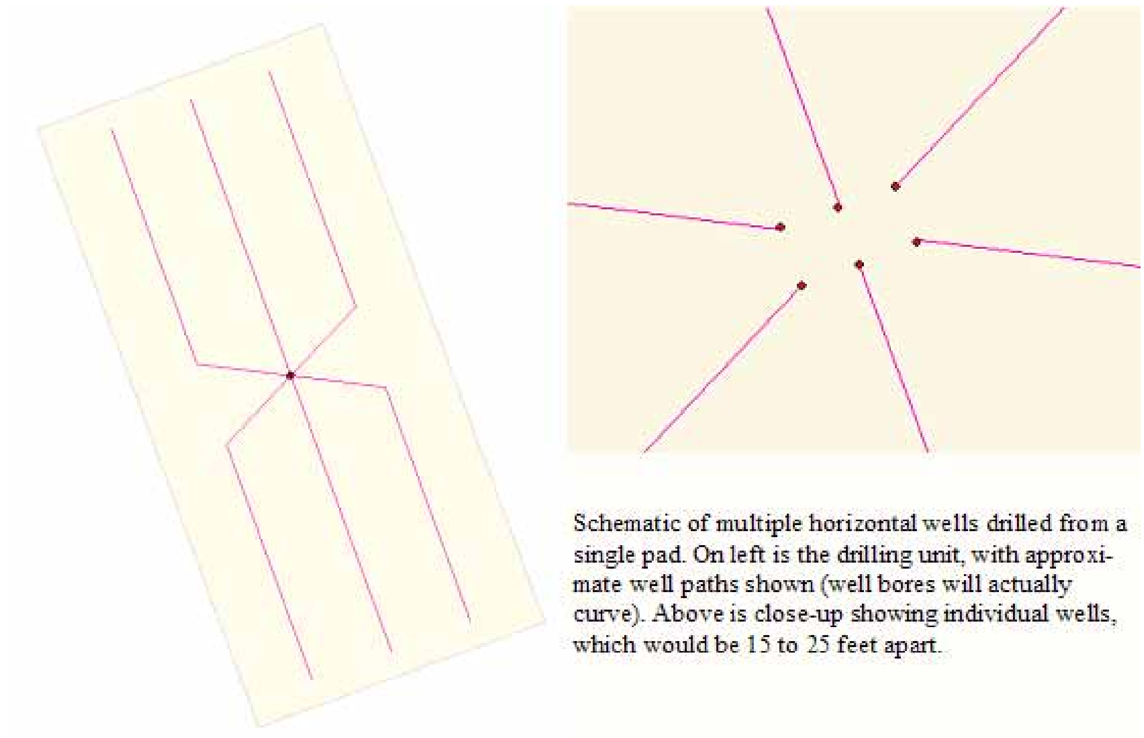


Figure 5-2 – Well spacing unit and wellbore paths

Because of the close well spacing at the surface, most operators have indicated that only one drilling rig at a time would be operating on any given well pad. One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently. Efficiency and the economics of mobilizing equipment and crews would dictate that all wells on a pad be drilled sequentially, with continuous activity during a single mobilization. However, this may be affected by the timing of compulsory integration proceedings if wellbores are proposed to intersect unleased acreage.[10] Other considerations may result in gaps between well drilling episodes at a well pad. For instance, early development in a given area may consist of initially drilling and stimulating one to three wells on a pad to test productivity, followed by the additional wells within the required three-year time frame. As development in a given area matures and the results become more predictable, the frequency of drilling and completing all the wells on each pad with continuous activity in a single mobilization would be expected to increase.

[10] ECL §23-0501 2.b. prohibits the wellbore from crossing unleased acreage prior to issuance of a compulsory integration order.

5.2.2.1 Reserve Pits on Multi-Well Pads

The GEIS describes the construction, use and reclamation of lined reserve pits, (also called "drilling pits" or "mud pits") to hold cuttings and fluids associated with the drilling process. Rather than using a separate pit for each well on a multi-well pad, operators may propose to maintain a single pit on the well pad until all wells are drilled and completed. The pit would need to be adequately sized to hold cuttings from all the wells, unless the cuttings are removed intermittently as needed to ensure adequate room for drilling-associated fluids and precipitation. Under existing regulations, fluid associated with each well would have to be removed within 45 days of the cessation of drilling operations, unless the operator has submitted a plan to use the fluids in subsequent operations and the Department has inspected and approved the pit.[11]

5.2.3 Drilling Mud

The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid. Operators who provided responses to the Department's information requests stated that the horizontal portion, drilled after any fresh water aquifers are sealed behind cemented surface casing, may be drilled with a mud that may be water-based, potassium chloride/polymer-based with a mineral oil lubricant, or synthetic oil-based. Synthetic oil-based muds are described as "food-grade" or "environmentally friendly." When drilling horizontally, mud is needed for (1) powering and cooling the downhole motor used for directional drilling, (2) using navigational tools which require mud to transmit sensor readings, (3) providing stability to the horizontal borehole while drilling and (4) efficiently removing cuttings from the horizontal hole. Other operators may drill the horizontal bore on air, using special equipment to control fluids and gases that enter the wellbore. Historically, most wells in New York are drilled on air and air drilling is addressed by the GEIS.

As described in the GEIS, used drilling mud is typically reconditioned for use at a subsequent well. It is managed on-site by the use of steel tanks that are part of the rig's "mud system." Some drilling rigs are equipped with closed-loop tank systems, so that neither used mud nor cuttings are discharged to reserve pits.

[11] 6 NYCRR 554.1(c)(3)

Photo 5.16 - Drilling rig mud system (blue tanks)

5.2.4 Cuttings

The very fine-grained rock fragments removed by the drilling process are returned to the surface in the drilling fluid and managed either within a closed-loop tank system or a lined on-site reserve pit.[12] As described in Section 5.13.1, the proper disposal method for cuttings is determined by the composition of drilling fluids used to return them to the surface.

5.2.4.1 Cuttings Volume

Horizontal drilling penetrates a greater linear distance of rock and therefore produces a larger volume of drill cuttings than does a well drilled vertically to the same depth below the ground surface. For example, a vertical well drilled to a total depth of 7,000 feet produces approximately 125 cubic yards of cuttings, while a horizontally drilled well to the same target

[12] Alpha

depth with a 3,000 foot lateral section produces approximately 165 cubic yards of cuttings (i.e., about one-third more). A multi-well site would produce that volume of cuttings from each well.

5.2.4.2 Naturally Occurring Radioactive Materials in Marcellus Cuttings

To determine NORM concentrations and the potential for exposure to Marcellus rock cuttings and cores, the Department conducted field and sample surveys using portable Geiger counter and gamma ray spectroscopy methods. Gamma ray spectroscopy analyses were performed on composited Marcellus samples collected from two vertical wells drilled through the Marcellus, one in Lebanon (Madison County), and one in Bath (Steuben County). Department staff also used a Geiger counter to screen three types of Marcellus samples: cores from the New York State Museum's collection in Albany; regional outcrops of the unit; and various Marcellus well sites from the west-central part of the state, where most of the vertical Marcellus wells in NYS are currently located. These screening data are presented in Table 5.2. The results, which indicate levels of radioactivity that are essentially background values, do not indicate an exposure concern for workers or the general public associated with Marcellus cuttings.

Table 5-2 - 2009 Marcellus Radiological Screening Data

Well (Depth)	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Crouch C 4H (1040 feet - 1115 feet)	31-053-26305-00-00	3/17/09	Lebanon (Madison)	K-40	14.438 +/- 1.727 pCi/g
				Tl-208	0.197 +/- 0.069 pCi/g
				Pb-210	2.358 +/- 1.062 pCi/g
				Bi-212	0.853 +/- 0.114 pCi/g
				Bi-214	1.743 +/- 0.208 pCi/g
				Pb-214	1.879 +/- 0.170 pCi/g
				Ra-226	1.843 +/- 0.573 pCi/g
				Ac-228	0.850 +/- 0.169 pCi/g
				Th-234	1.021 +/- 0.412 pCi/g
				U-235	0.185 +/- 0.083 pCi/g
Blair 2A (2550' - 2610')	31-101-02698-01-00	3/26/09	Bath (Steuben)	K-40	22.845 +/- 2.248 pCi/g
				Tl-208	0.381 +/- 0.065 pCi/g
				Pb-210	0.535 +/- 0.712 pCi/g
				Bi-212	1.174 +/- 0.130 pCi/g
				Bi-214	0.779 +/- 0.120 pCi/g
				Pb-214	0.868 +/- 0.114 pCi/g
				Ra-226	0.872 +/- 0.330 pCi/g
				Ac-228	1.087 +/- 0.161 pCi/g
				Th-234	0.567 +/- 0.316 pCi/g
				U-235	0.079 +/- 0.058 pCi/g

Media Screened	Well	Date	Location (County)	Results
Cores	Beaver Meadow 1	3/12/09	NYS Museum (Albany)	0.005 - 0.080 mR/hr
	Oxford 1	3/12/09	NYS Museum (Albany)	0.005 - 0.065 mR/hr
	75 NY-14	3/12/09	NYS Museum (Albany)	0.015 - 0.065 mR/hr
	EGSP #4	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Jim Tiede	3/12/09	NYS Museum (Albany)	0.005 - 0.025 mR/hr
	75 NY-18	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	75 NY-12	3/12/09	NYS Museum (Albany)	0.015 - 0.045 mR/hr
	75 NY-21	3/12/09	NYS Museum (Albany)	0.005 - 0.040 mR/hr
	75 NY-15	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Matejka	3/12/09	NYS Museum (Albany)	0.005 - 0.090 mR/hr
Outcrops	N/A	3/24/2009	Onesquethaw Creek (Albany)	0.02 - 0.04 mR/hr
	N/A	3/24/2009	DOT Garage, CR 2 (Albany)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	SR 20, near SR 166 (Otsego)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	Richfield Springs (Otsego)	0.01 - 0.06 mR/hr
	N/A	3/24/2009	SR 20 (Otsego)	0.01 - 0.03 mR/hr
	N/A	3/24/2009	Gulf Rd (Herkimer)	0.01 - 0.04 mR/hr
Well Sites	Beagell 2B	4/7/2009	Kirkwood (Broome)	0.04 mR/hr *
	Hulsebosch 1	4/2/2009	Elmira City (Chemung)	0.03 mR/hr *
	Bush S1	4/2/2009	Elmira (Chemung)	0.03 mR/hr *
	Parker 1	4/7/2009	Oxford (Chenango)	0.05 mR/hr *
	Donovan Farms 2	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Fee 1	3/30/2009	Sparta (Livingston)	0.02 mR/hr *
	Meter 1	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Schiavone 2	4/6/2009	Reading (Schuyler)	0.05 mR/hr *
	WGI 10	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	WGI 11	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	Calabro T1	3/26/2009	Orange (Schuyler)	0.03 mR/hr *
	Calabro T2	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Frost 2A	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Webster T1	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Haines 1	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	Haines 2	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	McDaniels 1A	4/1/2009	Urbana (Steuben)	0.03 mR/hr *
	Drumm G2	4/1/2009	Bradford (Steuben)	0.07 mR/hr *
	Hemley G2	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Lancaster M1	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Maxwell 1C	4/2/2009	Caton (Steuben)	0.07 mR/hr *
	Scudder 1	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Blair 2A	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Retherford 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Carpenter 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Cook 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Zinck 1	4/1/2009	Woodhull (Steuben)	0.07 mR/hr *
	Tiffany 1	4/7/2009	Owego (Tioga)	0.03 mR/hr *

5.3 Hydraulic Fracturing - Introduction

Hydraulic fracturing is a well stimulation technique which consists of pumping a fluid and a propping agent ("proppant") such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. No blast or explosion is created by the hydraulic fracturing process. The proppant holds the fractures open, allowing hydrocarbons to flow into the wellbore after injected fluids are recovered. Hydraulic fracturing technology was first developed in the late 1940s and, accordingly, it was addressed in the GEIS. It is estimated that as many as 90% of wells drilled in New York are hydraulically fractured. ICF International provides the following history:[13]

Hydraulic Fracturing Technological Milestones [14]	
Early 1900s	Natural gas extracted from shale wells. Vertical wells fracked with foam.
1983	First gas well drilled in Barnett Shale in Texas
1980-1990s	Cross-linked gel fracturing fluids developed and used in vertical wells
1991	First horizontal well drilled in Barnett Shale
1991	Orientation of induced fractures identified
1996	Slickwater fracturing fluids introduced
1996	Microseismic post-fracturing mapping developed
1998	Slickwater refracturing of originally gel-fracked wells
2002	Multi-stage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus shale[15]
2005	Increased emphasis on improving the recovery factor
2007	Use of multi-well pads and cluster drilling

The GEIS discusses, in Chapter 9, hydraulic fracturing operations using water-based gel and foam, and describes the use of water, hydrochloric acid and additives including surfactants, bactericides,[16] clay and iron inhibitors and nitrogen. The fracturing fluid is an engineered product; service providers vary the design of the fluid based on the characteristics of the

[13] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679. p. 3.

[14] Matthews, 2008, as cited by ICF International, 2009.

[15] Harper, 2008, as cited by ICF International, 2009.

[16] Bactericides must be registered for use in New York in accordance with ECL §33-0701. Well operators, service companies, and chemical supply companies were reminded of this requirement in an October 28, 2008 letter from the Division of Mineral Resources formulated in consultation with the Division of Solid and Hazardous Materials. This correspondence also reminded industry of the corresponding requirement that all bactericides be properly labeled and that the labels for such products be kept on-site during application and storage.

reservoir formation and the well operator's objectives. In the late 1990's, operators and service companies in other states developed a technology known as "slickwater fracturing" to develop shale formations, primarily by increasing the amount and proportion of water used, reducing the use of gelling agents and adding friction reducers. Any fracturing fluid may also contain scale and corrosion inhibitors.

ICF International, who reviewed the current state of practice of hydraulic fracturing for NYSERDA, states that the development of water fracturing technologies has reduced the quantity of chemicals required to hydraulically fracture target reservoirs and that slickwater treatments have yielded better results than gel treatments in the Barnett Shale.[17] Poor proppant suspension and transport characteristics of water versus gel are overcome by the low permeability of shale formations which allow the use of finer-grained proppants and lower proppant concentrations.[18] The use of friction reducers in slickwater fracturing procedures reduce the required pumping pressure at the surface, thereby reducing the number and power of pumping trucks needed.[19] In addition, according to ICF, slickwater fracturing causes less formation damage than other techniques such as gel fracturing.[20]

Both slickwater fracturing and foam fracturing have been proposed for Marcellus Shale development. As foam fracturing is already addressed by the GEIS, this document focuses on slickwater fracturing. This type of hydraulic fracturing is referred to herein as "high-volume hydraulic fracturing" because of the large water volumes required.

5.4 Fracturing Fluid

The fluid used for slickwater fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid.[21] The Department has collected compositional information on many of the additives proposed for use in fracturing shale formations in New York directly from chemical suppliers and service companies. This

---

[17] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679. pp. 10, 19.

[18] Ibid.

[19] Ibid., p. 12.

[20] Ibid., p. 19.

[21] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer*, pp. 61-62.

information has been evaluated by the Department's Air Resources and Water Divisions as well as the Bureaus of Water Supply Protection and Toxic Substances Assessment in the New York State Department of Health. It has also been reviewed by technical consultants contracted by NYSERDA[22] to conduct research related to the preparation of this document. Discussion of potential environmental impacts and mitigation measures in Chapters 6 and 7 of this SGEIS reflect analysis and input by all of the foregoing entities.

Six service companies[23] and twelve chemical suppliers[24] have provided additive product compositional information to the Department that includes more complete information than is available on product Material Safety Data Sheets (MSDSs)[25]. Altogether, some compositional information is on file with the Department for 197 products, with complete compositional information on file for 152 of those products. Within these products are approximately 260 unique chemicals whose CAS Numbers have been disclosed to the Department and an additional 40 compounds which require further disclosure since many are mixtures. Table 5.3 is an alphabetical list of all products for which complete chemical information has been provided to the Department. Table 5.4 is an alphabetical list of products for which only partial chemical composition information has been provided to the Department. Any product whose name does not appear within Table 5.3 or Table 5.4 was not evaluated in this SGEIS either because no chemical information was submitted to the Department or because the product was not proposed for use in fracturing operations at Marcellus shale wells or other wells targeting other low-permeability gas reservoirs. MSDSs are on file with the Department for most of the products listed. The Department considers MSDSs to be public information ineligible for exception from disclosure as trade secrets or confidential business information.

[22] Alpha Environmental Consultants, Inc., ICF International, URS Corporation

[23] BJ Services, Frac Tech Services, Halliburton, Superior Well Services, Universal Well Services, Schlumberger, Superior Well Services

[24] Baker Petrolite, CESI/Floteck, Champion Technologies/Special Products, Chem EOR, Cortec, Industrial Compounding, Kemira, Nalco, PfP Technologies, SNF Inc., Weatherford/Clearwater, and WSP Chemicals & Technology

[25] MSDSs are designed to provide employees and emergency personnel with proper procedures for handling, working with, and storing a particular substance and are regulated by the Occupational Safety and Health Administration (OSHA)'s Hazard Communication Standard, 29 CFR 1910.1200(g).

Table 5-3 Fracturing Additive Products – Full Composition Disclosure Made to the Department

Product Name
ABF
Acetic Acid 0.1-10%
Acid Pensurf / Pensurf
Activator W
AGA 150 / Super Acid Gell 150
AI-2
Aldacide G
Alpha 125
Ammonium Persulfate/OB Breaker
APB-1, Ammonium Persulfate Breaker
AQF-2
ASP-820
B315 / Friction Reducer B315
B317 / Scale Inhibitor B317
B859 / EZEFLO Surfactant B859 / EZEFLO F103 Surfactant
B867 / Breaker B867 / Breaker J218
B868 / EB-CLEAN B868 LT Encapsulated Breaker / EB-Clean J479 LT Encapsulated Breaker
B869 / Corrosion Inhibitor B869 / Corrosion Inhibitor A262
B875 / Borate Crosslinker B875 / Borate Crosslinker J532
B880 / EB-CLEAN B880 Breaker / EB-CLEAN J475 Breaker
B890 / EZEFLO Surfactant B890 / EZEFLO F100 Surfactant
B900 / EZEFLO Surfactant B900/ EZEFLO F108 Surfactant
B910 / Corrosion Inhibitor B910 / Corrosion Inhibitor A264
B916 / Gelling Agent ClearFRAC XT B916 / Gelling Agent ClearFRAC XT J590
BA-2
BA-20
BA-40L
BA-40LM
BC-140
BC-140 X2
BE-3S

BE-6
BE-7
BE-9
Bentone A-140
BF-1
BF-7 / BF-7L
BioClear 1000 / Unicide 1000
Bio-Clear 200 / Unicide 2000
Breaker FR
BXL-2, Crosslinker/ Buffer
BXL-STD / XL-300MB
Carbon Dioxide
CL-31
CLA-CHEK LP
CLA-STA XP
Clay Treat PP
Clay Treat TS
Clay Treat-3C
Clayfix II
Clayfix II plus
Cronox 245 ES/ CI-14
CS-250 SI
CS-650 OS, Oxygen Scavenger
CS-Polybreak 210
CS-Polybreak 210 Winterized
EB-4L
Enzyme G-NE
FE-1A
FE-2
FE-2A
FE-5A
Ferchek
Ferchek A
Ferrotrol 300L
Flomax 50
Flomax 70 / VX9173
FLOPAM DR-6000 / DR-6000
FLOPAM DR-7000 / DR-7000
Formic Acid
FR-46
FR-48W

FR-56
FRP-121
FRW-14
GasPerm 1000
GBL-8X / LEB-10X / GB-L / En-breaker
GBW-20C
GBW-30 Breaker
Green-Cide 25G / B244 / B244A
H015 / Hydrochloric Acid 15% H15
HAI-OS Acid Inhibitor
HC-2
High Perm SW-LB
HPH Breaker
HPH foamer
Hydrochloric Acid
Hydrochloric Acid (HCl)
HYG-3
IC 100L
ICA-720 / IC-250
ICA-8 / IC-200
ICI-3240
Inflo-250
InFlo-250W / InFlo-250 Winterized
Iron Check / Iron Chek
Iron Sta IIC / Iron Sta II
Isopropyl Alcohol
J313 / Water Friction-Reducing Agen J313
J534 / Urea Ammonium Nitrate Solution J534
J580 / Water Gelling Agent J580
K-34
K-35
KCI
L058 / Iron Stabilizer L58
L064 / Temporary Clay Stabilizer L64
LGC-35 CBM
LGC-36 UC
LGC-VI UC
Losurf 300M
M003 / Soda Ash M3
MA-844W
Methanol

MO-67
Morflo III
MSA-II
Muriatic Acid 36%
Musol A
N002 / Nitrogen N2
NCL-100
Nitrogen
Para Clear D290 / ParaClean II
Paragon 100 E+
PLURADYNE TDA 6
PSA-2L
PSI-720
PSI-7208
SAS-2
Scalechek LP-55
Scalechek LP-65
Scalehib 100 / Super Scale Inhibitor / Scale Clear SI-112
SGA II
Shale Surf 1000
Shale Surf 1000 Winterized
Sodium Citrate
SP Breaker
STIM-50 / LT-32
Super OW 3
Super Pen 2000
SuperGel 15
U042 / Chelating Agent U42
U066 / Mutual Solvent U66
Unicide 100 / EC6116A
Unifoam
Unigel 5F
UniHibA / SP-43X
UnihibG / S-11
Unislik ST 50 / Stim Lube
Vicon NF
WG-11
WG-17
WG-18
WG-35

WG-36
WLC-6
XL-1
XL-8
XLW-32
Xylene

Table 5-4 Fracturing Additive Products – Partial Composition Disclosure to the Department

Product Name
20 Degree Baume Muriatic Acid
AcTivator / 78-ACTW
AMB-100
B885 / ClearFRAC LT B885 / ClearFRAC LT J551A
B892 / EZEFLO B892 / EZEFLO F110 Surfactant
CL-22UC
Clay Master 5C
Corrosion Inhibitor A261
FAW- 5
FDP-S798-05
FDP-S819-05
FE ACID
FR-48
FRW-16
FRW-18
FRW-25M
GA 8713
GBW-15C
GBW-15L
GW-3LDF
HVG-1, Fast Hydrating Guar Slurry
ICA 400
Inflo-102
J134L / Enzyme Breaker J134L
KCLS-2, KCL Substitute
L065 / Scale Inhibitor L065
LP-65
Magnacide 575 Microbiocide
MSA ACID

Multifunctional Surfactant F105
Nitrogen, Refrigerated Liquid
OptiKleen-WF
Parasperse Cleaner
Product 239
S-150
SandWedge WF
Scalechek SCP-2
SilkWater FR-A
Super Sol 10/20/30
Unislick 30 / Cyanaflo 105L
WC-5584
WCS 5177 Corrosion Scale Inhibitor
WCW219 Combination Inhibitor
WF-12B Foamer
WF-12B Salt Inhibitor Stix
WF-12B SI Foamer/Salt Inhibitor
WF12BH Foamer
WFR-C

Information in sections 5.4.1-3 below was compiled primarily by URS Corporation, under contract to NYSERDA.

5.4.1 Properties of Fracturing Fluids

Additives are used in hydraulic fracturing operations to elicit certain properties and characteristics that would aide and enhance the operation. The desired properties and characteristics include:

- Non-reactive
- Non-flammable
- Minimal residuals
- Minimal potential for scale or corrosion.
- Low entrained solids
- Neutral pH (pH 6.5 – 7.5) for maximum polymer hydration

- Limited formation damage
- Appropriately modify properties of water to carry proppant deep into the shale
- Economical to modify fluid properties
- Minimal environmental effects

5.4.2 Classes of Additives

Table 5.5 lists the types, purposes and examples of additives that have been proposed to date for use in hydraulic fracturing of gas wells in New York State.

Table 5-5 - Types and Purposes of Additives Proposed for Use in New York State

Additive Type	Description of Purpose	Examples of Chemicals[26]
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%)
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2-Bromo-2-nitro-1,2-propanediol
Clay Stabilizer / Control	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride) [Potassium chloride (KCl)]
Corrosion Inhibitor	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol
Crosslinker	The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows	Potassium hydroxide

[26] Chemicals in brackets [ ] have not been proposed for use in the State of New York to date, but are known to be used in other states or shale formations.

Additive Type	Description of Purpose	Examples of Chemicals[26]
	the fluid to carry more proppant into the fractures.	
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM)
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid; thioglycolic acid
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol; polyacrylate
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol

5.4.3 Composition of Fracturing Fluids

The composition of the fracturing fluid used may vary from one geologic basin or formation to another in order to meet the specific needs of each operation; but the range of additive types available for potential use remains the same. There are a number of different chemical compositions for each additive type; however, only one product of each type is typically utilized in any given gas well. The selection may be driven by the formation and potential interactions between additives. Additionally not all additive types will be utilized in every fracturing job.

A sample composition by weight of fracture fluid is provided in Figure 5.3; this composition is based on data from the Fayetteville Shale.[27] Based on this data, approximately 90 percent of the fracture fluid is water; another approximately 9 percent is proppant (see Photo 5.17); the remainder, typically less than 0.5 percent consists of chemical additives listed above.

[27] Similar to the Marcellus Shale, the Fayetteville Shale is a marine shale rich in unoxidized carbon (i.e. a black shale). The two shales are at similar depths, and vertical and horizontal wells have been drilled/fractured at both shales.

Photo 5.17 - Sand used in hydraulic fracturing operation in Bradford County, PA.

Barnett Shale is considered to be the first instance of extensive high-volume hydraulic fracture technology use; the technology has since been applied in other areas such as the Fayetteville Shale and the Haynesville Shale. URS notes that data collected from applications to drill Marcellus Shale wells in New York indicate that the typical fracture fluid composition for operations in the Marcellus Shale is similar to the provided composition in the Fayetteville Shale.

Even though no horizontal wells have been drilled in the Marcellus Shale in New York, applications filed to date indicate that it is realistic to expect that the composition of fracture fluids used in the Marcellus Shale would be similar from one operation to the next. One potential exception is that additional data provided separately to the Department indicates that biocides have comprised up to 0.03% of fracturing fluid instead of 0.001% as noted in Figure 5.3.

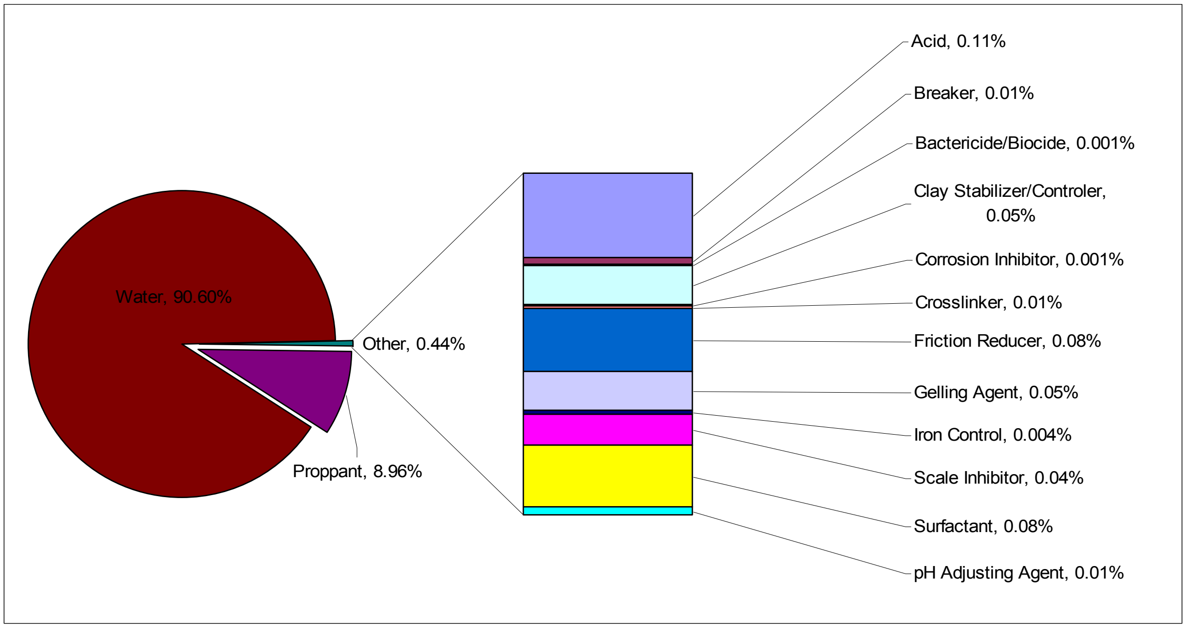


Figure 5-3 - Sample Fracture Fluid Composition by Weight

Each product within the twelve classes of additives may be made up of one or more chemical constituents. Table 5.6 is a list of chemical constituents and their CAS numbers, that have been extracted from complete product chemical compositional information and Material Safety Data Sheets submitted to the NYSDEC for nearly 200 products used or proposed for use in hydraulic fracturing operations in the Marcellus Shale area of New York. It is important to note that several manufacturers and suppliers provide similar chemicals (i.e. chemicals that would serve the same purpose) for any class of additive, and that not all types of additives are used in a single well. Table 5.6 represents constituents of all hydraulic-fracturing-related chemicals submitted to NYSDEC to date for potential use at shale wells in the State, only a handful of which would be utilized in a single well.

Data provided to NYSDEC to date indicates similar fracturing fluid compositions for vertically and horizontally drilled wells.

Table 5-6 - Chemical Constituents in Additives/Chemicals[28,29]

CAS Number[30]	Chemical Constituent
2634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one
95-63-6	1,2,4 trimethylbenzene
123-91-1	1,4 Dioxane
3452-07-1	1-eicosene
629-73-2	1-hexadecene
112-88-9	1-octadecene
1120-36-1	1-tetradecene
10222-01-2	2,2 Dibromo-3-nitrilopropionamide
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride
73003-80-2	2,2-Dobromomalonamide
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride
52-51-7	2-Bromo-2-nitro-1,3-propanediol
111-76-2	2-Butoxy ethanol
1113-55-9	2-Dibromo-3-Nitriloprionamide (2-Monobromo-3-nitriilopropionamide)
104-76-7	2-Ethyl Hexanol
67-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer
9003-03-6	2-propenoic acid, homopolymer, ammonium salt
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite
107-19-7	2-Propyn-1-ol / Progargyl Alcohol
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,
115-19-5	3-methyl-1-butyn-3-ol
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol
64-19-7	Acetic acid
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine
108-24-7	Acetic Anhydride
67-64-1	Acetone
79-06-1	Acrylamide

[28] Table 5.6 is a list of chemical constituents and their CAS numbers that have been extracted from complete chemical compositions and Material Safety Data Sheets submitted to the NYSDEC.

[29] These are the chemical constituents of all chemical additives proposed to be used in New York for hydraulic fracturing operations at shale wells. Only a few chemicals will be used in a single well; the list of chemical constituents used in an individual well will be correspondingly smaller.

[30] Chemical Abstracts Service (CAS) is a division of the American Chemical Society. CAS assigns unique numerical identifiers to every chemical described in the literature. The intention is to make database searches more convenient, as chemicals often have many names. Almost all molecule databases today allow searching by CAS number.

CAS Number[30]	Chemical Constituent
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride
15085-02-3	Acrylamide-sodium acrylate copolymer
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent
64743-02-8	Alkenes
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt
9016-45-9	Alkylphenol ethoxylate surfactants
1327-41-9	Aluminum chloride
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated
71011-04-6	Amines, Ditallow alkyl, ethoxylated
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates
1336-21-6	Ammonia
631-61-8	Ammonium acetate
68037-05-8	Ammonium Alcohol Ether Sulfate
7783-20-2	Ammonium bisulfate
10192-30-0	Ammonium Bisulphite
12125-02-9	Ammonium Chloride
7632-50-0	Ammonium citrate
37475-88-0	Ammonium Cumene Sulfonate
1341-49-7	Ammonium hydrogen-difluoride
6484-52-2	Ammonium nitrate
7727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate
1762-95-4	Ammonium Thiocyanate
7664-41-7	Aqueous ammonia
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay
71-43-2	Benzene
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide
10043-35-3	Boric acid
1303-86-2	Boric oxide / Boric Anhydride
71-36-3	Butan-1-ol
68002-97-1	C10 - C16 Ethoxylated Alcohol
68131-39-5	C12-15 Alcohol, Ethoxylated
10043-52-4	Calcium chloride
124-38-9	Carbon Dioxide
68130-15-4	Carboxymethylhydroxypropyl guar
9012-54-8	Cellulase / Hemicellulase Enzyme
9004-34-6	Cellulose
10049-04-4	Chlorine Dioxide
77-92-9	Citric Acid

CAS Number[30]	Chemical Constituent
94266-47-4	Citrus Terpenes
61789-40-0	Cocamidopropyl Betaine
68155-09-9	Cocamidopropylamine Oxide
68424-94-2	Coco-betaine
7758-98-7	Copper (II) Sulfate
31726-34-8	Crissanol A-55
14808-60-7	Crystalline Silica (Quartz)
7447-39-4	Cupric chloride dihydrate
1120-24-7	Decyldimethyl Amine
2605-79-0	Decyl-dimethyl Amine Oxide
3252-43-5	Dibromoacetonitrile
25340-17-4	Diethylbenzene
111-46-6	Diethylene Glycol
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt
28757-00-8	Diisopropyl naphthalenesulfonic acid
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt
7398-69-8	Dimethyldiallylammonium chloride
25265-71-8	Dipropylene glycol
139-33-3	Disodium Ethylene Diamine Tetra Acetate
5989-27-5	D-Limonene
123-01-3	Dodecylbenzene
27176-87-0	Dodecylbenzene sulfonic acid
42504-46-1	Dodecylbenzenesulfonate isopropanolamine
50-70-4	D-Sorbitol / Sorbitol
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase
149879-98-1	Erucic Amidopropyl Dimethyl Betaine
89-65-6	Erythorbic acid, anhydrous
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer
107-21-1	Ethane-1,2-diol / Ethylene Glycol
9002-93-1	Ethoxylated 4-tert-octylphenol
68439-50-9	Ethoxylated alcohol
126950-60-5	Ethoxylated alcohol
67254-71-1	Ethoxylated alcohol (C10-12)
68951-67-7	Ethoxylated alcohol (C14-15)
68439-46-3	Ethoxylated alcohol (C9-11)
66455-15-0	Ethoxylated Alcohols
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)
68439-51-0	Ethoxylated Alcohols (C12-14)
78330-21-9	Ethoxylated branch alcohol
34398-01-1	Ethoxylated C11 alcohol
61791-12-6	Ethoxylated Castor Oil
61791-29-5	Ethoxylated fatty acid, coco
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine
68439-45-2	Ethoxylated hexanol

CAS Number[30]	Chemical Constituent
9036-19-5	Ethoxylated octylphenol
9005-67-8	Ethoxylated Sorbitan Monostearate
9004-70-3	Ethoxylated Sorbitan Trioleate
64-17-5	Ethyl alcohol / ethanol
100-41-4	Ethyl Benzene
97-64-3	Ethyl Lactate
9003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)
75-21-8	Ethylene oxide
5877-42-9	Ethyloctynol
68526-86-3	Exxal 13
61790-12-3	Fatty Acids
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea
9043-30-5	Fatty alcohol polyglycol ether surfactant
7705-08-0	Ferric chloride
7782-63-0	Ferrous sulfate, heptahydrate
50-00-0	Formaldehyde
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide
75-12-7	Formamide
64-18-6	Formic acid
110-17-8	Fumaric acid
65997-17-3	Glassy calcium magnesium phosphate
111-30-8	Glutaraldehyde
56-81-5	Glycerol / glycerine
9000-30-0	Guar Gum
9000-30-01	Guar Gum
64742-94-5	Heavy aromatic petroleum naphtha
9025-56-3	Hemicellulase
7647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid
7722-84-1	Hydrogen Peroxide
79-14-1	Hydroxy acetic acid
35249-89-9	Hydroxyacetic acid ammonium salt
9004-62-0	Hydroxyethyl cellulose
5470-11-1	Hydroxylamine hydrochloride
39421-75-5	Hydroxypropyl guar
35674-56-7	Isomeric Aromatic Ammonium Salt
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic
64-63-0	Isopropanol
98-82-8	Isopropylbenzene (cumene)
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline
8008-20-6	Kerosene
64742-81-0	Kerosine, hydrodesulfurized

CAS Number[30]	Chemical Constituent
63-42-3	Lactose
64742-95-6	Light aromatic solvent naphtha
1120-21-4	Light Paraffin Oil
14807-96-6	Magnesium Silicate Hydrate (Talc)
1184-78-7	methanamine, N,N-dimethyl-, N-oxide
67-56-1	Methanol
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched
8052-41-3	Mineral spirits / Stoddard Solvent
141-43-5	Monoethanolamine
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride
64742-48-9	Naphtha (petroleum), hydrotreated heavy
91-20-3	Naphthalene
38640-62-9	Naphthalene bis(1-methylethyl)
93-18-5	Naphthalene, 2-ethoxy-
68909-18-2	N-benzyl-alkyl-pyridinium chloride
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine
7727-37-9	Nitrogen, Liquid form
68412-54-4	Nonylphenol Polyethoxylate
121888-66-2	Organophilic Clays
64742-65-0	Petroleum Base Oil
64741-68-0	Petroleum naphtha
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt
8000-41-7	Pine Oil
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized
56449-46-8	Polyethlene glycol oleate ester
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate
9005-65-6	Polyoxyethylene Sorbitan Monooleate
61791-26-2	Polyoxylated fatty amine salt
127-08-2	Potassium acetate
12712-38-8	Potassium borate
1332-77-0	Potassium borate
20786-60-1	Potassium Borate
584-08-7	Potassium carbonate
7447-40-7	Potassium chloride
590-29-4	Potassium formate
1310-58-3	Potassium Hydroxide
13709-94-9	Potassium metaborate
24634-61-5	Potassium Sorbate
112926-00-8	Precipitated silica / silica gel
57-55-6	Propane-1,2-diol, or Propylene glycol

CAS Number[30]	Chemical Constituent
107-98-2	Propylene glycol monomethyl ether
68953-58-2	Quaternary Ammonium Compounds
62763-89-7	Quinoline,2-methyl-, hydrochloride
15619-48-4	Quinolinium, 1-(phenylmethl),chloride
7631-86-9	Silica, Dissolved
5324-84-5	Sodium 1-octanesulfonate
127-09-3	Sodium acetate
95371-16-7	Sodium Alpha-olefin Sulfonate
532-32-1	Sodium Benzoate
144-55-8	Sodium bicarbonate
7631-90-5	Sodium bisulfate
7647-15-6	Sodium Bromide
497-19-8	Sodium carbonate
7647-14-5	Sodium Chloride
7758-19-2	Sodium chlorite
3926-62-3	Sodium Chloroacetate
68-04-2	Sodium citrate
6381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt
2836-32-0	Sodium Glycolate
1310-73-2	Sodium Hydroxide
7681-52-9	Sodium hypochlorite
7775-19-1	Sodium Metaborate .8H_2O
10486-00-7	Sodium perborate tetrahydrate
7775-27-1	Sodium persulphate
9003-04-7	Sodium polyacrylate
7757-82-6	Sodium sulfate
1303-96-4	Sodium tetraborate decahydrate
7772-98-7	Sodium Thiosulfate
1338-43-8	Sorbitan Monooleate
57-50-1	Sucrose
5329-14-6	Sulfamic acid
112945-52-5	Syntthetic Amorphous / Pyrogenic Silica / Amorphous Silica
68155-20-4	Tall Oil Fatty Acid Diethanolamine
8052-48-0	Tallow fatty acids sodium salt
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized
68647-72-3	Terpene and terpenoids
68956-56-9	Terpene hydrocarbon byproducts
533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)
75-57-0	Tetramethyl ammonium chloride
64-02-8	Tetrasodium Ethylenediaminetetraacetate
68-11-1	Thioglycolic acid
62-56-6	Thiourea
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone
108-88-3	Toluene

CAS Number[30]	Chemical Constituent
81741-28-8	Tributyl tetradecyl phosphonium chloride
68299-02-5	Triethanolamine hydroxyacetate
112-27-6	Triethylene Glycol
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated
150-38-9	Trisodium Ethylenediaminetetraacetate
5064-31-3	Trisodium Nitrilotriacetate
7601-54-9	Trisodium ortho phosphate
57-13-6	Urea
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer
7732-18-5	Water
1330-20-7	Xylene

Chemical Constituent
Aliphatic acids
Aliphatic alcohol glycol ether
Alkyl Aryl Polyethoxy Ethanol
Alkylaryl Sulfonate
Aromatic hydrocarbons
Aromatic ketones
Oxyalkylated alkylphenol
Petroleum distillate blend
Polyethoxylated alkanol
Polymeric Hydrocarbons
Salt of amine-carbonyl condensate
Salt of fatty acid/polyamine reaction product
Sugar
Surfactant blend

Chemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined and provided by Public Officers Law §87.2(d) and the Department's implementing regulation, 6 NYCRR 616.7.

5.4.3.1 Chemical Categories and Health Information

DEC requested assistance from NYSDOH in identifying potential exposure pathways and constituents of concern associated with high-volume hydraulic fracturing for low-permeability gas reservoir development. DEC provided DOH with fracturing additive product constituents based on Material Safety Data Sheets (MSDSs) and product-composition disclosures for hydraulic fracturing additive products that were provided by well-service companies and the chemical supply companies that manufacture the products.

Compound-specific toxicity data are very limited for many chemical additives to fracturing fluids, so chemicals potentially present in fracturing fluids were grouped together into categories according to their chemical structure (or function in the case of microbiocides) in Table 5.7, compiled by NYSDOH. As explained above, any given individual fracturing job will only involve a handful of chemicals and may not include every category of chemicals.

Table 5-7 - Categories based on chemical structure of potential fracturing fluid constituents. Chemicals are grouped in order of ascending CAS Number by category.

Chemical	CAS Number
Amides	
Formamide	75-12-7
acrylamide	79-06-1
Amines	
urea	57-13-6
thiourea	62-56-6
tetramethyl ammonium chloride	75-57-0
monoethanolamine	141-43-5
Decyldimethyl Amine	1120-24-7
methanamine, N,N-dimethyl-, N-oxide	1184-78-7
Decyl-dimethyl Amine Oxide	2605-79-0
dimethyldiallylammonium chloride	7398-69-8
polydimethyl dially ammonium chloride	26062-79-3
dodecylbenzenesulfonate isopropanolamine	42504-46-1
N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	44992-01-0
2-acryloyloxyethyl(benzyl)dimethylammonium chloride	46830-22-2
ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	54076-97-0
Cocamidopropyl Betaine	61789-40-0
polyoxylated fatty amine salt	61791-26-2
quinoline, 2-methyl, hydrochloride	62763-89-7
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68139-30-0
tall oil fatty acid diethanolamine	68155-20-4
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68424-94-2
amines, tallow alkyl, ethoxylated, acetates	68551-33-7

Chemical	CAS Number
quaternary ammonium compounds, bis(hydrogenated tallow alkyl) dimethyl, salts with bentonite	68953-58-2
amines, ditallow alkyl, ethoxylated	71011-04-6
amines, C-12-14-tert-alkyl, ethoxylated	73138-27-9
benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	74153-51-8
Erucic Amidopropyl Dimethyl Betaine	149879-98-1
Petroleum Distillates	
light paraffin oil	1120-21-4
kerosene	8008-20-6
stoddard solvent	8052-41-3
petroleum naphtha	64741-68-0
Multiple names listed under same CAS#: LVP aliphatic hydrocarbon, hydrotreated light distillate, low odor paraffin solvent, paraffin solvent, paraffinic napthenic solvent, isoparaffinic solvent, distillates (petroleum) hydrotreated light, petroleum light distillate, aliphatic hydrocarbon, petroleum distillates	64742-47-8
naphtha, hydrotreated heavy	64742-48-9
petroleum base oil	64742-65-0
kerosine (petroleum, hydrodesulfurized)	64742-81-0
kerosine (petroleum, hydrodesulfurized)	64742-88-7
Multiple names listed under same CAS#: heavy aromatic petroleum naphtha, light aromatic solvent naphtha	64742-94-5
light aromatic solvent naphtha	64742-95-6
alkenes, C> 10 α-	64743-02-8
Aromatic Hydrocarbons	
benzene	71-43-2
naphthalene	91-20-3
naphthalene, 2-ethoxy	93-18-5
1,2,4-trimethylbenzene	95-63-6
cumene	98-82-8
ethyl benzene	100-41-4
toluene	108-88-3
dodecylbenzene	123-01-3
xylene	1330-20-7

Chemical	CAS Number
diethylbenzene	25340-17-4
naphthalene bis(1-methylethyl)	38640-62-9
Alcohols	
sorbitol (or) D-sorbitol	50-70-4
Glycerol	56-81-5
propylene glycol	57-55-6
ethanol	64-17-5
isopropyl alcohol	67-63-0
methanol	67-56-1
isopropyl alcohol	67-63-0
butanol	71-36-3
2-ethyl-1-hexanol	104-76-7
propargyl alcohol	107-19-7
ethylene glycol	107-21-1
Diethylene Glycol	111-46-6
3-methyl-1-butyn-3-ol	115-19-5
Ethyloctynol	5877-42-9
Glycol Ethers & Ethoxylated Alcohols	
propylene glycol monomethyl ether	107-98-2
ethylene glycol monobutyl ether	111-76-2
triethylene glycol	112-27-6
oxylated 4-tert-octylphenol	9002-93-1
ethoxylated sorbitan trioleate	9005-70-3
Polysorbate 80	9005-65-6
ethoxylated sorbitan monostearate	9005-67-8
Polyethylene glycol-(phenol) ethers	9016-45-9
Polyethylene glycol-(phenol) ethers	9036-19-5
fatty alcohol polyglycol ether surfactant	9043-30-5
Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-	24938-91-8
Dipropylene glycol	25265-71-8
Nonylphenol Ethoxylate	26027-38-3
crissanol A-55	31726-34-8
Polyethylene glycol-(alcohol) ethers	34398-01-1
Trimethylolpropane, Ethoxylated, Propoxylated	52624-57-4
Polyethylene glycol-(alcohol) ethers	60828-78-6
Ethoxylated castor oil [PEG-10 Castor oil]	61791-12-6

Chemical	CAS Number
ethoxylated alcohols	66455-15-0
ethoxylated alcohol	67254-71-1
Ethoxylated alcohols (9 – 16 carbon atoms)	68002-97-1
ammonium alcohol ether sulfate	68037-05-8
Polyethylene glycol-(alcohol) ethers	68131-39-5
Polyethylene glycol-(phenol) ethers	68412-54-4
ethoxylated hexanol	68439-45-2
Polyethylene glycol-(alcohol) ethers	68439-46-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68439-50-9
C12-C14 ethoxylated alcohols	68439-51-0
Exxal 13	68526-86-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68551-12-2
alcohols, C-14-15, ethoxylated	68951-67-7
Ethoxylated Branched C11-14, C-13-rich Alcohols	78330-21-9
Ethoxylated alcohols (9 – 16 carbon atoms)	84133-5-6
alcohol ethoxylated	126950-60-5
Polyethylene glycol-(phenol) ethers	127087-87-0
Microbiocides	
bronopol	52-51-7
glutaraldehyde	111-30-8
2-monobromo-3-nitrilopropionamide	1113-55-9
1,2-benzisothiazolin-3-one	2634-33-5
dibromoacetonitrile	3252-43-5
dazomet	533-74-4
Hydrogen Peroxide	7722-84-1
2,2-dibromo-3-nitrilopropionamide	10222-01-2
tetrakis	55566-30-8
2,2-dibromo-malonamide	73003-80-2
Organic Acids and Related Chemicals	
tetrasodium EDTA	64-02-8
formic acid	64-18-6
acetic acid	64-19-7
sodium citrate	68-04-2
thioglycolic acid	68-11-1
hydroxyacetic acid	79-14-1
erythorbic acid, anhydrous	89-65-6

Chemical	CAS Number
ethyl lactate	97-64-3
acetic anhydride	108-24-7
fumaric acid	110-17-8
potassium acetate	127-08-2
sodium acetate	127-09-3
Disodium Ethylene Diamine Tetra Acetate	139-33-3
Trisodium Ethylenediamine tetraacetate	150-38-9
sodium benzoate	532-32-1
potassium formate	590-29-4
ammonium acetate	631-61-8
Sodium Glycolate	2836-32-0
Sodium Chloroacetate	3926-62-3
trisodium nitrilotriacetate	5064-31-3
sodium 1-octanesulfonate	5324-84-5
Sodium Erythorbate	6381-77-7
ammonium citrate	7632-50-0
tallow fatty acids sodium salt	8052-48-0
quinolinium, 1-(phenylmethyl), chloride	15619-48-4
diethylenetriamine penta (methylenephonic acid) sodium salt	22042-96-2
potassium sorbate	24634-61-5
dodecylbenzene sulfonic acid	27176-87-0
diisopropyl naphthalenesulfonic acid	28757-00-8
hydroxyacetic acid ammonium salt	35249-89-9
isomeric aromatic ammonium salt	35674-56-7
ammonium cumene sulfonate	37475-88-0
Fatty Acids	61790-12-3
fatty acid, coco, ethoxylated	61791-29-5
2-propenoic acid, telomer with sodium hydrogen sulfite	66019-18-9
carboxymethylhydroxypropyl guar	68130-15-4
fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	68188-40-9
triethanolamine hydroxyacetate	68299-02-5
alkyl (C14-C16) olefin sulfonate, sodium salt	68439-57-6
triethanolamine hydroxyacetate	68442-62-6
N-benzyl-alkyl-pyridinium chloride	68909-18-2
phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis (methylene)]]tetrakis-ammonium salt	70714-66-8
tributyl tetradecyl phosphonium chloride	81741-28-8
sodium alpha-olefin sulfonate	95371-16-7

Chemical	CAS Number
benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	119345-04-9
Polymers	
guar gum	9000-30-0
guar gum	9000-30-01
2-propenoic acid, homopolymer, ammonium salt	9003-03-6
low mol wt polyacrylate	9003-04-7
Low Mol. Wt. Polyacrylate	9003-04-7
Multiple names listed under same CAS#: oxirane, methyl-, polymer with oxirane, Ethylene Glycol-Propylene Glycol Copolymer	9003-11-6
cellulose	9004-34-6
hydroxyethyl cellulose	9004-62-0
cellulase/hemicellulase enzyme	9012-54-8
hemicellulase	9025-56-3
acrylamide-sodium acrylate copolymer	25085-02-3
Vinylidene Chloride/Methylacrylate Copolymer	25038-72-6
polyethylene glycol	25322-68-3
copolymer of acrylamide and sodium acrylate	25987-30-8
formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	29316-47-0
hemicellulase	37288-54-3
acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	38193-60-1
oxiranemthanaminium, N,N,N-trimethyl-, chloride, homopolymer (aka: polyepichlorohydrin, trimethylamine quaternized)	51838-31-4
polyethlene glycol oleate ester	56449-46-8
polymer with 2-propenoic acid and sodium 2-propenoate	62649-23-4
modified thiourea polymer	68527-49-1
methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	68891-11-2
acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	69418-26-4
2-propenoic acid, polymer with sodium phosphinate (1:1)	71050-62-9
formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	153795-76-7
Minerals, Metals and other Inorganics	
carbon dioxide	124-38-9
sodium bicarbonate	144-55-8
Sodium Carbonate	497-19-8
Potassium Carbonate	584-08-7
Boric Anhydride (a.k.a. Boric Oxide)	1303-86-2
sodium tetraborate decahydrate	1303-96-4
Potassium Hydroxide	1310-58-3

Chemical	CAS Number
sodium hydroxide	1310-73-2
aluminum chloride, basic	1327-41-9
sodium tetraborate decahydrate	1332-77-0
aqua ammonia 29.4%	1336-21-6
ammonium hydrogen-difluoride	1341-49-7
ammonium thiocyanate	1762-95-4
sulfamic acid	5329-14-6
hydroxylamine hydrochloride	5470-11-1
ammonium nitrate	6484-52-2
cupric chloride dihydrate	7447-39-4
potassium chloride	7447-40-7
Trisodium ortho phosphate	7601-54-9
Non-Crystaline Silica	7631-86-9
sodium bisulfate	7631-90-5
hydrochloric acid	7647-01-0
sodium chloride	7647-14-5
sodium bromide	7647-15-6
aqueous ammonia	7664-41-7
sodium hypochlorite	7681-52-9
ferric chloride	7705-08-0
nitrogen	7727-37-9
ammonium persulfate	7727-54-0
water	7732-18-5
sodium sulfate	7757-82-6
sodium chlorite	7758-19-2
sodium thousulfate	7772-98-7
Sodium Metaborate.8H2O	7775-19-01
Sodium Persulphate	7775-27-1
ferrous sulfate, heptahydrate	7782-63-0
ammonium bisulfate	7783-20-2
boric acid	10043-35-3
Calcium Chloride	10043-52-4
Chlorine Dioxide	10049-04-4
ammonium bisulphite	10192-30-0
sodium perborate tetrahydrate	10486-00-7
ammonium chloride	12125-02-9
potassium borate	12714-38-8
potassium metaborate	13709-94-9

Chemical	CAS Number
Magnesium Silicate Hydrate (Talc)	14807-96-6
crystalline silica (quartz)	14808-60-7
glassy calcium magnesium phosphate	65997-17-3
silica gel	112926-00-8
synthetic amorphous, pyrogenic silica	112945-52-5
synthetic amorphous, pyrogenic silica	121888-66-2
Miscellaneous	
formaldehyde	50-00-0
Sucrose	57-50-1
lactose	63-42-3
acetone	67-64-1
ethylene oxide	75-21-8
1-octadecene	112-88-9
1,4-dioxane	123-91-1
1-hexadecene	629-73-2
1-tetradecene	1120-36-1
sorbitan monooleate	1338-43-8
1-eicosene	3452-07-1
D-Limonene	5989-27-5
Pine Oil	8000-41-7
2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	27776-21-2
3,5,7-triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride	51229-78-8
alkenes	64743-02-8
Cocamidopropyl Oxide	68155-09-9
terpene and terpenoids	68647-72-3
terpene hydrocarbon byproducts	68956-56-9
tar bases, quinoline derivs., benzyl chloride-quaternized	72780-70-7
citrus terpenes	94266-47-4
organophilic clays	121888-68-4
Listed without CAS Number[31]	
belongs with amines	
proprietary quaternary ammonium compounds	NA
quaternary ammonium compound	NA

[31] Constituents listed without CAS #'s were tentatively placed in chemical categories based on the name listed on the MSDS or within confidential product composition disclosures. Many of the constituents reported without CAS #s, are mixtures which require further disclosure to DEC.

Chemical	CAS Number
triethanolamine (tea) 85%, drum	NA
Quaternary amine	NA
Fatty amidoalkyl betaine	NA
belongs with petroleum distillates	
petroleum distillate blend	NA
belongs with aromatic hydrocarbons	
aromatic hydrocarbon	NA
aromatic ketones	NA
belongs with glycol ethers and ethoxylated alcohols	
Acetylenic Alcohol	NA
Aliphatic Alcohols, ethoxylated	NA
Aliphatic Alcohol glycol ether	NA
Ethoxylated alcohol linear	NA
Ethoxylated alcohols	NA
aliphatic alcohol polyglycol ether	NA
alkyl aryl polyethoxy ethanol	NA
misture of ethoxylated alcohols	NA
nonylphenol ethoxylate	NA
oxyalkylated alkylphenol	NA
polyethoxylated alkanol	NA
Oxyalkylated alcohol	NA
belongs with organic acids	
Aliphatic acids derivative	NA
Aliphatic Acids	NA
hydroxy acetic acid	NA
citric acid 50%, base formula	NA
Alkylaryl Sulfonate	NA
belongs with polymers	
hydroxypropyl guar	NA
2-acrylamido-2-methylpropanesulphonic acid sodium salt polymer	NA
belongs with minerals, metals and other inorganics	
precipitated silica	NA
sodium hydroxide	NA
belongs with miscellaneous	
epa inert ingredient	NA
non-hazardous ingredients	NA
proprietary surfactant	NA
salt of fatty acid/polyamine reaction product	NA

Chemical	CAS Number
salt of amine-carbonyl condensate	NA
surfactant blend	NA
sugar	NA
polymeric hydrocarbon mixture	NA

Although exposure to fracturing additives would require a failure of operational controls such as an accident, a spill or other non-routine incident, the health concerns noted by NYSDOH for each chemical category are discussed below. The discussion is based on available qualitative hazard information for chemicals from each category. Qualitative descriptions of potential health concerns discussed below generally apply to all exposure routes (i.e., ingestion, inhalation or skin contact) unless a specific exposure route is mentioned. For most chemical categories, health information is available for only some of the chemicals in the category. More specific assessment of health risks associated with a contamination event would entail an analysis based on the specific additives being used and site-specific information about exposure pathways and environmental contaminant levels. Potential human health risks of a specific event would be assessed by comparison of case-specific exposure data with existing drinking standards or ambient air guidelines.[32] If needed, other chemical-specific health comparison values would be developed, based on a case-specific review of toxicity literature for the chemicals involved. A case-specific assessment would include information on how potential health effects might differ (both qualitatively and quantitatively) depending on the route of exposure.

Petroleum Distillate Products

Petroleum-based constituents are included in some fracturing fluid additive products. They are listed in MSDSs as various petroleum distillate fractions including kerosene, petroleum naphtha, aliphatic hydrocarbon, petroleum base oil, heavy aromatic petroleum naphtha, mineral spirits, hydrotreated light petroleum distillates, stoddard solvent or aromatic hydrocarbon. These can be found in a variety of additive products including corrosion inhibitors, friction reducers and solvents. Petroleum distillate products are mixtures that vary in their composition, but they have similar adverse health effects. Accidental ingestion that results in exposure to large amounts of

[32] 10 NYCRR Part 5: Drinking Water Supplies; Subpart 5-1: Public Water Systems, Maximum Contaminant Levels; NYS DEC Policy DAR-1: Guidelines for the Control of Toxic Ambient Air Contaminants

petroleum distillates is associated with adverse effects on the gastrointestinal system and central nervous system. Skin contact with kerosene for short periods can cause skin irritation, blistering or peeling. Breathing petroleum distillate vapors can adversely affect the central nervous system.

Aromatic Hydrocarbons

Some fracturing additive products contain specific aromatic hydrocarbon compounds that can also occur in petroleum distillates (benzene, toluene, ethylbenzene and xylene or BTEX; naphthalene and related derivatives, trimethylbenzene, diethylbenzene, dodecylbenzene, cumene). BTEX compounds are associated with adverse effects on the nervous system, liver, kidneys and blood-cell-forming tissues. Benzene has been associated with an increased risk of leukemia in industrial workers who breathed elevated levels of the chemical over long periods of time in workplace air. Exposure to high levels of xylene has damaged the unborn offspring of laboratory animals exposed during pregnancy. Naphthalene is associated with adverse effects on red blood cells when people consumed naphthalene mothballs or when infants wore cloth diapers stored in mothballs. Laboratory animals breathing naphthalene vapors for their lifetimes had damage to their respiratory tracts and increased risk of nasal and lung tumors.

Glycols

Glycols occur in several fracturing fluid additives including crosslinkers, breakers, clay and iron controllers, friction reducers and scale inhibitors. Propylene glycol has low inherent toxicity and is used as an additive in food, cosmetic and drug products. High exposure levels of ethylene glycol adversely affect the kidneys and reproduction in laboratory animals.

Glycol Ethers

Glycol ethers and related ethoxylated alcohols and phenols are present in fracturing fluid additives, including corrosion inhibitors, surfactants and friction reducers. Some glycol ethers (e.g., monomethoxyethanol, monoethoxyethanol, propylene glycol monomethyl ether, ethylene glycol monobutyl ether) can affect the male reproductive system and red blood cell formation in laboratory animals at high exposure levels.

Alcohols

Alcohols are present in some fracturing fluid additive products, including corrosion inhibitors, foaming agents, iron and scale inhibitors and surfactants. Exposure to high levels of some alcohols (e.g., ethanol, methanol) affect the central nervous system.

Amides

Acrylamide is used in some fracturing fluid additives to create polymers during the stimulation process. These polymers are part of some friction reducers and scale inhibitors. Although the reacted polymers that form during fracturing are of low inherent toxicity, unreacted acrylamide may be present in the fracturing fluid, or breakdown of the polymers could release acrylamide back into the flowback water. High levels of acrylamide damage the nervous system and reproductive system in laboratory animals and also cause cancer in laboratory animals.

Formamide may be used in some corrosion inhibitors products. Ingesting high levels of formamide adversely affects the female reproductive system in laboratory animals.

Amines

Amines are constituents of fracturing fluid products including corrosion inhibitors, cross-linkers, friction reducers, iron and clay controllers and surfactants. Chronic ingestion of mono-, di- or tri-ethanolamine adversely affects the liver and kidneys of laboratory animals.

Some quaternary ammonium compounds, such as dimethyldiallyl ammonium chloride, can react with chemicals used in some systems for drinking water disinfection to form nitrosamines. Nitrosamines cause genetic damage and cancer when ingested by laboratory animals.

Organic Acids, Salts and Related Chemicals

Organic acids and related chemicals are constituents of fracturing fluid products including acids, buffers, corrosion and scale inhibitors, friction reducers, iron and clay controllers, solvents and surfactants. Some short-chain organic acids such as formic, acetic and citric acids can be corrosive or irritating to skin and mucous membranes at high concentrations. However, acetic and citric acids are regularly consumed in foods (such as vinegar and citrus fruits) where they occur naturally at lower levels that are not harmful.

Some foaming agents and surfactant products contain organic chemicals included in this category that contain a sulfonic acid group (sulfonates). Exposure to elevated levels of sulfonates is irritating to the skin and mucous membranes.

Microbiocides

Microbiocides are antimicrobial pesticide products intended to inhibit the growth of various types of bacteria in the well. A variety of different chemicals are used in different microbiocide products that are proposed for Marcellus wells. Toxicity information is limited for several of the microbiocide chemicals. However, for some, high exposure has caused effects in the respiratory and gastrointestinal tracts, the kidneys, the liver and the nervous system in laboratory animals.

Other Constituents

The remaining chemicals listed in MSDSs and confidential product composition disclosures provided to DEC are included in Table 5.7 under the following categories: polymers, miscellaneous chemicals that did not fit another chemical category and product constituents that were not identified by a Chemical Abstract Service (CAS) number. Readily available health effects information is lacking for many of these constituents, but two that are relatively well studied are discussed here. In the event of environmental contamination involving chemicals lacking readily available health effects information, the toxicology literature would have to be researched for chemical-specific toxicity data.

Formaldehyde is listed as a constituent in some corrosion inhibitors, scale inhibitors and surfactants. In most cases, the concentration listed in the product is relatively low (< 1%) and is listed alongside a formaldehyde-based polymer constituent. Formaldehyde is irritating to tissues when it comes into direct contact with them. The most common symptoms include irritation of the skin, eyes, nose, and throat, along with increased tearing. Severe pain, vomiting, coma, and possible death can occur after drinking large amounts of formaldehyde. Several studies of laboratory rats exposed for life to high amounts of formaldehyde in air found that the rats developed nose cancer. Some studies of humans exposed to lower amounts of formaldehyde in workplace air found more cases of cancer of the nose and throat (nasopharyngeal cancer) than expected, but other studies have not found nasopharyngeal cancer in other groups of workers exposed to formaldehyde in air.

1,4-dioxane may be used in some surfactant products. 1,4-Dioxane is irritating to the eyes and nose when vapors are breathed. Exposure to very high levels may cause severe kidney and liver effects and possibly death. Studies in animals have shown that breathing vapors of 1,4-dioxane, swallowing liquid 1,4-dioxane or contaminated drinking water, or having skin contact with liquid 1,4-dioxane affects mainly the liver and kidneys. Laboratory rats and mice that drank water containing 1,4-dioxane during most of their lives developed liver cancer; the rats also developed cancer inside the nose.

Conclusions

The hydraulic fracturing product additives proposed for use in NYS and used for fracturing horizontal Marcellus shale wells in other states contain similar types of chemical constituents as the products that have been used for many years for hydraulic fracturing of traditional vertical wells in NYS. Some of the same products are used in both well types. The total amount of fracturing additives and water used in hydraulic fracturing of horizontal wells is considerably larger than for traditional vertical wells. This suggests the potential environmental consequences of an upset condition could be proportionally larger for horizontal well drilling and fracturing operations. As mentioned earlier, the 1992 GEIS addressed hydraulic fracturing in Chapter 9, and NYSDOH's review did not identify any potential exposure situations associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the GEIS.

5.5 Transport of Hydraulic Fracturing Additives

Fracturing additives are transported in "DOT-approved" trucks or containers. The trucks are typically flat-bed trucks that carry a number of strapped-on plastic totes which contain the liquid additive products. (Totes are further described in Section 5.6.) Liquid products used in smaller quantities are transported in one-gallon sealed jugs carried in the side boxes of the flat-bed. Some liquid constituents, such as hydrochloric acid, are transferred in tank trucks.

Dry additives are transported on flat-beds in 50- or 55-pound bags which are set on pallets containing 40 bags each and shrink-wrapped, or in five-gallon sealed plastic buckets. When smaller quantities of some dry products such as powdered biocides are used, they are contained in a double-bag system and may be transported in the side boxes of the truck that constitutes the blender unit.

Regulations that reference “DOT-approved” trucks or containers that are applicable to the transportation and storage of hazardous frac additives refer to federal (USDOT) regulations for registering and permitting commercial motor carriers and drivers, and established standards for hazardous containers. The United Nations (UN) also has established standards and criteria for containers. New York is one of many states where the state agency (NYSDOT) has adopted the federal regulations for transporting hazardous materials interstate. The NYSDOT has its own requirements for intrastate transportation. [33]

Transporting frac additives that are hazardous is comprehensively regulated under existing regulations. The regulated materials include the hazardous additives and mixtures containing thresholds of hazardous materials. These transported materials are maintained in the USDOT or UN-approved storage containers until the materials are consumed at the drill sites.[34]

5.5.1 USDOT Transportation Regulations[35]

The federal Hazardous Material Transportation Act (HMTA, 1975) and the Hazardous Materials Transportation Uniform Safety Act (HMTUSA, 1990) are the basis for federal hazardous materials transportation law (49 U.S.C.) and give regulatory authority to the Secretary of the USDOT to:

- “Designate material (including an explosive, radioactive, infectious substance, flammable or combustible liquid, solid or gas, toxic, oxidizing, or corrosive material, and compressed gas) or a group or class of material as hazardous when the Secretary determines that transporting the material in commerce in a particular amount and form may pose an unreasonable risk to health and safety or property; and

- “Issue regulations for the safe transportation, including security, of hazardous material in intrastate, interstate, and foreign commerce” (PHMSA, 2009).

[33] Alpha Environmental Consultants, Inc., 2009. *Technical Contributions to the Draft Supplemental Generic Environmental Impact Satement (dSGEIS) for the NYSDEC Oil, Gas and Solution Mining Regulatory Program.*

[34] Ibid.

[35] Ibid.

The Code of Federal Regulations (CFR), Title 49, includes the Hazardous Materials Transportation Regulations, Parts 100 through 199. Federal hazardous materials regulations include:

- Hazardous materials classification (Parts 171 and 173)
- Hazard communication (Part 172)
- Packaging requirements (Parts 173, 178, 179, 180)
- Operational rules (Parts 171, 172, 173, 174, 175, 176, 177)
- Training and security (part 172)
- Registration (Part 171)

The extensive regulations address the potential concerns involved in transporting hazardous fracturing additives, such as Loading and Unloading (Part 177), General Requirements for Shipments and Packaging (Part 173), Specifications for Packaging (Part 178), and Continuing Qualification and Maintenance of Packaging (Part 180).

Regulatory functions are carried out by the following USDOT agencies:

- Pipeline and Hazardous Materials Safety Administration (PHMSA)
- Federal Motor Carrier Safety Administration (FMCSA)
- Federal Aviation Administration (FAA)
- United States Coast Guard (USCG)

Each of these agencies shares in promulgating regulations and enforcing the federal hazmat regulations. State, local, or tribal requirements may only preempt federal hazmat regulations if one of the federal enforcing agencies issues a waiver of preemption based on accepting a regulation that offers an equal or greater level of protection to the public and does not unreasonably burden commerce.

The interstate transportation of hazardous materials for motor carriers is regulated by FMCSA and PHMSA. FMCSA establishes standards for commercial motor vehicles, drivers, and companies, and enforces 49 CFR Parts 350-399. FMCSA's responsibilities include monitoring and enforcing regulatory compliance, with focus on safety and financial responsibility. PHMSA's enforcement activities relate to "the shipment of hazardous materials, fabrication, marking, maintenance, reconditioning, repair or testing of multi-modal containers that are represented, marked, certified, or sold for use in the transportation of hazardous materials." PHMSA's regulatory functions include issuing Hazardous Materials Safety Permits; issuing rules and regulations for safe transportation; issuing, renewing, modifying, and terminating special permits and approvals for specific activities; and receiving, reviewing, and maintaining records, among other duties.

5.5.2 New York State DOT Transportation Regulations[36]

New York State requires all registrants of commercial motor vehicles to obtain a USDOT number. New York has adopted the FMCSA regulations CFR 49, Parts 390, 391, 392, 393, 395, and 396, and the Hazardous Materials Transportation Regulations, Parts 100 through 199, as those regulations apply to interstate highway transportation (NYSDOT, 6/2/09). There are minor exemptions to these federal regulations in NYCRR Title17 Part 820, "New York State Motor Carrier Safety Regulations"; however, the exemptions do not directly relate to the objectives of this review.

The NYS regulations include motor vehicle carriers that operate solely on an intrastate basis. Those carriers and drivers operating in intrastate commerce must comply with 17 NYCRR Part 820, in addition to the applicable requirements and regulations of the NYS Vehicle and Traffic Law and the NYS Department of Motor Vehicles (DMV), including the regulations requiring registration or operating authority for transporting hazardous materials from the USDOT or the NYSDOT Commissioner.

Part 820.8 (Transportation of hazardous materials) states "Every person … engaged in the transportation of hazardous materials within this State shall be subject to the rules and regulations contained in this Part." The regulations require that the material be "properly classed, described, packaged, clearly marked, clearly labeled, and in the condition for shipment…" [820.8(b)]; that the material "is handled and transported in accordance with this

[36] Ibid.

Part" [(820.8(c)]; "require a shipper of hazardous materials to have someone available at all times, 24 hours a day, to answer questions with respect to the material being carried and the hazards involved" [(820.8.(f)]; and provides for immediately reporting to "the fire or police department of the local municipality or to the Division of State Police any incident that occurs during the course of transportation (including loading, unloading and temporary storage) as a direct result of hazardous materials" [820.8 (h)].

Part 820 specifies that "In addition to the requirements of this Part, the Commissioner of Transportation adopts the following sections and parts of Title 49 of the Code of Federal Regulations with the same force and effect… for classification, description, packaging, marking, labeling, preparing, handling and transporting all hazardous materials, and procedures for obtaining relief from the requirements, all of the standards, requirements and procedures contained in sections 107.101, 107.105, 107.107, 107.109, 107.111, 107.113, 107.117, 107.121, 107.123, Part 171, except section 171.1, Parts 172 through 199, including appendices, inclusive and Part 397.

5.6 On-Site Storage and Handling of Hydraulic Fracturing Additives

Prior to use, additives remain at the wellsite in the containers and on the trucks in which they are transported and delivered. Storage time is generally less than a week for economic and logistical reasons, materials are not delivered until fracturing operations are set to commence, and only the amount needed for scheduled continuous fracturing operations is delivered at any one time.

As detailed in Section 5.4.3, there are 12 classes of additives, based on their purpose or use; not all classes would be used at every well; and only one product in each class would typically be used per job. Therefore, although the chemical lists in Tables 5.5 and 5.6 reflect nearly 200 products, no more than 12 products and far fewer chemicals than listed would be present at one time at any given site.

When the hydraulic fracturing procedure commences, hoses are used to transfer liquid additives from storage containers to a truck-mounted blending unit. The flat-bed trucks that deliver liquid totes to the site may be equipped with their own pumping systems for transferring the liquid additive to the blending unit when fracturing operations are in progress. Flat-beds that do not have their own pumps rely on pumps attached to the blending unit. Additives delivered in tank trucks are pumped to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is not stored, but is immediately mixed with proppant and pumped into the cased and cemented wellbore. This process is conducted and monitored by qualified personnel, and devices such as manual valves provide additional controls when liquids are transferred. Common observed practices during visits to drill sites in the northern tier of Pennsylvania included lined containments and protective barriers where chemicals were stored and blending took place.[37]

5.6.1 Summary of Additive Container Types

The most common containers are 220-gallon to 375-gallon high-density polyethylene (HDPE) totes, which are generally cube-shaped and encased in a metal cage. These totes have a bottom release port to transfer the chemicals, which is closed and capped during transport, and a top fill port with a screw-on cap and temporary lock mechanism. Photo 5.18 depicts a transport truck with totes.

[37] Alpha Environmental Consultants, Inc., 2009. *Technical Contributions to the Draft Supplemental Generic Environmental Impact Satement (dSGEIS) for the NYSDEC Oil, Gas and Solution Mining Regulatory Program.*

Photo 5.18 - Transport trucks with totes

To summarize, the storage containers at any given site during the short period of time between delivery and completion of continuous fracturing operations will consist of all or some of the following:

- Plastic totes encased in metal cages, ranging in volume from 220 gallons to 375 gallons, which are strapped on to flat bed trucks pursuant to USDOT and NYSDOT regulations
- Tank trucks (see Photo 5.19)
- Palletized 50-55 gallon bags, made of coated paper or plastic (40 bags per pallet, shrink-wrapped as a unit and then wrapped again in plastic)
- One-gallon jugs with perforated sealed twist lids stored in side boxes on the flat-bed
- Smaller double-bag systems stored in side boxes on the blending unit

5.6.2 *NYSDEC Programs for Bulk Storage*[38]

The Department regulates bulk storage of petroleum and hazardous chemicals under 6 NYCRR Parts 612-614 for Petroleum Bulk Storage (PBS) and Parts 595-597 for Chemical Bulk Storage (CBS). The PBS regulations do not apply to non-stationary tanks; however, all petroleum spills, leaks, and discharges must be reported to the Department (613.8).

Photo 5.19 - Transport trucks for water (above) and hydraulic fracturing acid (HCl) (below)

The CBS regulations that potentially may apply to fracturing fluids include non-stationary tanks, barrels, drums or other vessels that store 1000-Kg or greater for a period of 90 consecutive days. Liquid fracturing chemicals are stored in non-stationary containers but most likely will not be stored on-site for 90 consecutive days; therefore, those chemicals are exempt from Part 596,

[38] Alpha, 2009.

"Registration of Hazardous Substance Bulk Storage Tanks" unless the storage period criteria is exceeded. These liquids typically are trucked to the drill site in volumes required for consumptive use and only days before the fracturing process. Dry chemical additives, even if stored on site for 90 days, would be exempt from 6 NYCRR because the dry materials are stored in 55-lb bags secured on plastic-wrapped pallets.

The facility must maintain inventory records for all applicable non-stationary tanks including those that do not exceed the 90-day storage threshold. The CBS spill regulations and reporting requirements also apply regardless of the storage thresholds or exemptions. Any spill of a "reportable quantity" listed in Part 597.2(b), must be reported within 2 hours unless the spill is contained by secondary containment within 24 hours and the volume is completely recovered. Spills of any volume must be reported within two (2) hours if the release could cause a fire, explosion, contravention of air or water quality standards, illness, or injury. Forty-two of the chemicals listed in Table 5.6 are listed in Part 597.2(b).

5.7 Source Water for High-Volume Hydraulic Fracturing

As described below, it is estimated that 2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a 4,000-foot lateral wellbore. Operators may withdraw water from surface or ground water sources themselves or may purchase it from suppliers. The suppliers may be municipalities with excess capacity in their public supply systems, or industrial entities with wastewater effluent streams that meet usability criteria for hydraulic fracturing. Potential environmental impacts of water sourcing are discussed in Chapter 6, and mitigation measures including jurisdictional regulatory programs and potential alternate water sources are discussed in Chapter 7. Photos 5.20 a, b & c depict a water withdrawal facility along the Chemung River in the northern tier of Pennsylvania.

Factors affecting usability of a given source include:[39]

Availability – The "owner" of the source needs to be identified, contact made, and agreements negotiated.

---

[39] URS Corporation, 2009. *A Survey of a Few Water Resources Issues Associated with Gas Production in the Marcellus Shale.* Water Consulting Services in Support of the Supplemental Generic Environmental Impact Statement for Natural Gas Production, NYSERDA Contract PO Number 10666.

Distance/route from the source to the point of use – The costs of trucking large quantities of water increases and water supply efficiency decreases when longer distances and travel times are involved. Also, the selected routes need to consider roadway wear, bridge weight limits, local zoning limits, impacts on residents, and related traffic concerns.

Available quantity – Use of fewer, larger water sources avoids the need to utilize multiple smaller sources.

Reliability – A source that is less prone to supply fluctuations or periods of unavailability would be more highly valued than an intermittent and less steady source.

Accessibility –Water from deep mines and saline aquifers may be more difficult to access than a surface water source unless adequate infrastructure is in place. Access to a municipal or industrial plant or reservoir may be inconvenient due to security or other concerns. Access to a stream may be difficult due to terrain, competing land uses, or other issues.

Quality of water – The fracturing fluid serves a very specific purpose at different stages of the fracturing process. The composition of the water could affect the efficacy of the additives and equipment used. The water may require pre-treatment or additional additives may be needed to overcome problematic characteristics.

Potential concerns with water quality include scaling from precipitation of barium sulfate and calcium sulfate; high concentrations of chlorides, which could increase the need for friction reducers; very high or low pH (e.g. water from mines); high concentrations of iron (water from quarries or mines) which could potentially plug fractures; microbes that can accelerate corrosion, scaling or other gas production; and high concentrations of sulfur (e.g. water from flu gas desulfurization impoundments), which could contaminate natural gas. In addition, water sources of variable quality could present difficulties.

Permittability – Applicable permits and approvals would need to be identified and assessed as to feasibility and schedule for obtaining approvals, conditions and limitations on approval that could impact the activity or require mitigation, and initial and ongoing fees and charges.

Preliminary discussions with regulating authorities would be prudent to identify fatal flaws or obstacles.

Disposal – Proper disposal of flowback from hydraulic fracturing will be necessary, or appropriate treatment for re-use provided. Utilizing an alternate source with sub-standard quality water could add to treatment and disposal costs.

Cost – Sources that have a higher associated cost to acquire, treat, transport, permit, access or dispose, typically will be less desirable.

5.7.1 Delivery of Source Water to the Well Pad

Water may be delivered by truck or pipeline directly from the source to the well pad, or may be delivered by trucks or pipeline from centralized water storage or staging facilities consisting of tanks or engineered impoundments. Photo 5.21 shows a fresh water pipeline in Bradford County, Pennsylvania, to move fresh water from an impoundment to a well pad.

At the well pad, water is typically stored in 500-barrel steel tanks.

Potential environmental impacts related to water transportation, including the number and duration of truck trips for moving both fluid and temporary storage tanks, are addressed in Chapter 6. Mitigation measures are described in Chapter 7.

5.7.2 Use of Centralized Impoundments for Fresh Water Storage

Operators have indicated that centralized water storage impoundments will likely be utilized as part of a water management plan. Such facilities would allow the operators to withdraw water from surface water bodies during periods of high flow and store the water for use in future hydraulic fracturing activities, thus avoiding or reducing the need to withdraw water during lower flow periods when the potential for negative impacts to aquatic environments and municipal drinking water suppliers is greater.

The proposed engineered impoundments would likely be constructed from compacted earth excavated from the impoundment site and then compressed to form embankments around the excavated area. Typically, such impoundments would then be lined to minimize the loss of water due to infiltration.

It is likely that an impoundment would service well pads within a radius of up to four miles, and that impoundment volume could be several million gallons with surface acreage of up to five acres. The siting and sizing of such impoundments would be affected by factors such as terrain, environmental conditions, natural barriers, and population density, as well as by the operators' lease positions. It is not anticipated that a single centralized impoundment would service wells from more than one well operator.

Photo 5.23 depicts a centralized freshwater impoundment and its construction.

5.7.2.1 Impoundment Regulation

Water stored within an impoundment represents potential energy which, if released, could cause personal injury, property damage and natural resource damage. In order for an impoundment to safely fulfill its intended function, the impoundment must be properly designed, constructed, operated and maintained.

As defined by Section 3 Title 5 of Article 15 of the Environmental Conservation Law (ECL), a dam is any artificial barrier, including any earthen barrier or other structure, together with its appurtenant works, which impounds or will impound waters. As such, any engineered impoundment designed to store water for use in hydraulic fracturing operations is considered to be a dam and is therefore subject to regulation in accordance with the ECL, NYSDEC's Dam Safety Regulations and the associated Protection of Waters permitting program.

Photos 5.20 a & b Fortuna SRBC-approved Chemung River water withdrawal facility, Towanda PA. Source:

Photo 5.20 c Fresh water supply pond. Black pipe in pond is a float to keep suction away from pond bottom liner. Ponds are completely enclosed by wire fence. Source: NYS DEC 2009.

Photo 5.21 Water pipeline from Fortuna central freshwater impoundments, Troy PA. Source: NYS DEC 2009.

Photo 5.23 Construction of freshwater impoundment in Upshur Co. WV. Source: Chesapeake Energy

Statutory Authority

Chapter 364, Laws of 1999 amended ECL Sections 15-0503, 15-0507 and 15-0511 to revise the applicability criteria for the dam permit requirement and provide the Department the authority to regulate dam operation and maintenance for safety purposes. Additionally the amendments established the dam owners' responsibility to operate and maintain dams in a safe condition.

Although the revised permit criteria, which are discussed below, became effective in 1999, implementing the regulation of dam operation and maintenance for all dams (regardless of the applicability of the permit requirement) necessitated the promulgation of regulations. As such, the Department issued proposed dam safety regulations in February 2008, followed by revised draft regulations in May 2009 and adopted the amended regulations in August 2009.These adopted regulations contain amendments to Part 673 and to portions of Parts 608 and 621 of Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York.[40]

Permit Applicability

In accordance with ECL §15-0503 (1)(a), a Protection of Waters Permit is required for the construction, reconstruction, repair, breach or removal of an impoundment provided the impoundment has:

(1) a height equal to or greater than fifteen feet[41], or

(2) a maximum impoundment capacity equal to or greater than three million gallons[42].

If, however, either of the following exemption criteria apply, no permit is required:

(1) a height equal to or less than six feet regardless of the structure's impoundment capacity, or

(2) an impoundment capacity not exceeding one million gallons regardless of the structure's height

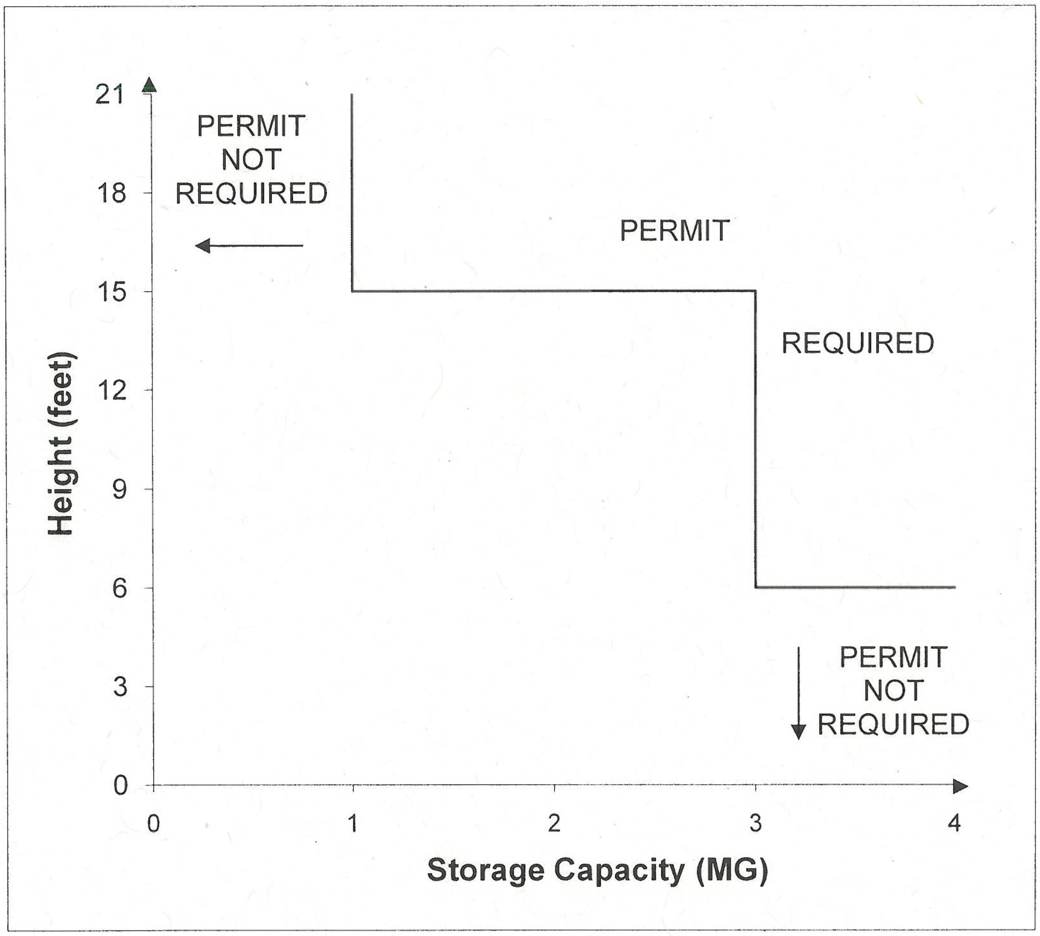
[40] NYSDEC Notice of Adoption of Amendments to Dam Safety Regulations

[41] Maximum height is measured as the height from the downstream [outside] toe of the dam at its lowest point to the highest point at the top of the dam.

[42] Maximum impounding capacity is measured as the volume of water impounded when the water level is at the top of the dam.

Figure 5.4 depicts the aforementioned permitting criteria and demonstrates that a permit is required for any impoundment whose height and storage capacity plot above or to the right of the solid line, while those impoundments whose height and storage capacity plot below or to the left of the solid line, do not require a permit.

Figure 5-4- Protection of Waters – Dam Safety Permitting Criteria



Protection of Waters - Dam Safety Permitting Process

If a proposed impoundment meets or exceeds the permitting thresholds discussed above, the well operator proposing use of the impoundment is required to apply for a Protection of Waters Permit though the Department's Division of Environmental Permits.

A pre-application conference is recommended and encouraged for permit applicants, especially those who are first-time applicants. Such a conference allows the applicant to explain the proposed project and to get preliminary answers to any questions concerning project plans, application procedures, standards for permit issuance and information on any other applicable permits pertaining to the proposed impoundment. It is also recommended that this conference occur early in the planning phase, prior to detailed design and engineering work, so that Department staff can review the proposal and comment on its conformance with permit issuance standards, which may help to avoid delays later in the process.

Application forms, along with detailed application instructions are available on the Department's website[43] and from the Regional Permit Administrator[44] for the county where the impoundment project is proposed. A complete application package[45] must include the following items:

- A completed Joint Application for Permit
- A completed Application Supplement D-1, which is specific to the construction, reconstruction or repair of a dam or other impoundment structure
- A location map showing the precise location of the project
- A plan of the proposed project
- Hydrological, hydraulic, and soils information, as required on the application form prescribed by the Department
- An Engineering Design Report sufficiently detailed for Department evaluation of the safety aspects of the proposed impoundment that shall include:
    - A narrative description of the proposed project;
    - The proposed Hazard Classification of the impoundment as a result of the proposed activities or project;
    - A hydrologic investigation of the watershed and an assessment of the hydraulic adequacy of the impoundment;

[43] Downloadable permit application forms are available at Hhttp://www.dec.ny.gov/permits/6338.htmlH.

[44] Contact information for the Department's Regional Permit Administrators is available on the Department's website at Hhttp://www.dec.ny.gov/about/558.htmlH.

[45] Further details regarding the permit application requirement are available on the instructions which accompany the Supplement D-1 application form which is available at Hhttp://www.dec.ny.gov/docs/permits_ej_operations_pdf/spplmntd1.pdfH.

  - An evaluation of the foundation and surrounding conditions, and materials involved in the structure of the dam, in sufficient detail to accurately define the design of the dam and assess its safety, including its structural stability;

  - Structural and hydraulic design studies, calculation and procedures, which shall, at a minimum, be consistent with generally accepted sound engineering practice in the field of dam design and safety; and

  - A description of any proposed permanent instrument installations in the impoundment

- Construction plans and specifications that are sufficiently detailed for Department evaluation of the safety aspects of the dam

Additionally the following information may also be required as part of the permit application:

- Recent clear photographs of the project site mounted on a separate sheet labeled with the view shown and the date of the photographs.

- Information necessary to satisfy the requirements of the State Environmental Quality Review Act (SEQR), including: a completed Environmental Assessment Form (EAF) and, in certain cases, a Draft Environmental Impact Statement (DEIS)

- Information necessary to satisfy the requirements of the State Historic Preservation Act (SHPA) including a completed structural and archaeological assessment form and, in certain cases, an archaeological study as described by SHPA

- Written permission from the landowner for the filing of the project application and undertaking of the proposed activity.

- Other information which Department staff may determine is necessary to adequately review and evaluate the application.

In order to ensure that an impoundment is properly designed and constructed, the design, preparation of plans, estimates and specifications, and the supervision of the erection, reconstruction, or repair of an impoundment must be conducted by a licensed professional engineer. This individual should utilize the Department's technical guidance document "Guidelines for Design of Dams"[46], which conveys sound engineering practices and outlines

[46] "Guidelines for Design of Dams" is available on the Department's website at http://www.dec.ny.gov/docs/water_pdf/damguideli.pdf or upon request from the DEC Regional Permit Administrator.

hydrologic and other criteria that should be utilized in designing and constructing an engineered impoundment.

All application materials should be submitted to the appropriate Regional Permit Administrator for the county in which the project is proposed. Once the application is declared complete, the Department will review the applications, plans and other supporting information submitted and, in accordance with 6 NYCRR §608.7, may (1) grant the permit; (2) grant the permit with conditions as necessary to protect the health, safety, or welfare of the people of the state, and its natural resources; or (3) deny the permit.

The Department's review will determine whether the proposed impoundment is consistent with the standards contained within 6 NYCRR §608.8, considering such issues as:

(1) the environmental impacts of the proposal, including effects on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality[47]; hydrology[48]; water course and waterbody integrity;

(2) the adequacy of design and construction techniques for the structure;

(3) operation and maintenance characteristics;

(4) the safe commercial and recreational use of water resources;

(5) the water dependent nature of a use;

(6) the safeguarding of life and property; and

(7) natural resource management objectives and values.

Additionally, the Department's review of the proposed impoundment will include the assignment of a Hazard Classification in accordance with 6 NYCRR§673.5. Hazard Classifications are assigned to dams and impoundments according to the potential impacts of a dam failure, the particular physical characteristics of the impoundment and its location, and may be irrespective of the size of the impoundment, as appropriate. The 4 potential Hazard Classifications, as defined by subdivision (b) of Section 673.5, are as follows:

[47] Water Quality may include criteria such as temperature, dissolved oxygen, and suspended solids.

[48] Hydrology may include such criteria as water velocity, depth, discharge volume, and flooding potential

- Class “A” or “Low Hazard”: A failure is unlikely to result in damage to anything more than isolated or unoccupied buildings, undeveloped lands, minor roads such as town or country roads; is unlikely to result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise unlikely to pose the threat of personal injury, substantial economic loss or substantial environmental damage.

- Class “B” or “Intermediate Hazard”: A failure may result in damage to isolate homes, main highways, and minor railroads; may result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise likely to pose the threat of personal injury and/or substantial economic loss or substantial environmental damage. Loss of human life is not expected.

- Class “C” or “High Hazard”: A failure may result in widespread or serious damage to home(s); damage to main highways, industrial or commercial buildings, railroads, and/or important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; or substantial environmental damage; such that the loss of human life or widespread substantial economic loss is likely.

- Class “D” or “Negligible or No Hazard”: A dam or impoundment that has been breached or removed, or has failed or otherwise no longer materially impounds waters, or a dam that was planned but never constructed. Class “D” dams are considered to be defunct dams posing negligible or no hazard. The Department may retain pertinent records regarding such dams.

The basis for the issuance of a permit will be a determination that the proposal is in the public interest in that the proposal is reasonable and necessary, will not endanger the health, safety or welfare of the people of the State of New York, and will not cause unreasonable, uncontrolled or unnecessary damage to the natural resources of the state.

Timing of Permit Issuance

Application submission, time frames and processing procedures for the Protection of Waters Permit are all governed by the provisions of Article 70 of the ECL – the Uniform Procedures Act (UPA) – and its implementing regulations, 6 NYCRR § 621. In accordance with subdivision (a)(2)(iii) of Section 621 as recently amended, only repairs of existing dams inventoried by the Department are considered minor projects under the UPA and therefore the construction, reconstruction or removal of an impoundment is considered to be a major project and is thus subject to the associated UPA timeframes.

Failure to obtain the required permit before commencing work subjects the well operator and any contractors engaged in the work to DEC enforcement action which may include civil or criminal court action, fines, an order to remove structures or materials or perform other remedial action, or both a fine and an order.

Operation and Maintenance of Any Impoundment

The Department's document ""An Owners Guidance Manual for the Inspection and Maintenance of Dams in New York State" should be utilized by all impoundment owners, as it provides important, direct and indirect steps they can take to reduce the consequences of an impoundment failure.

The Dam Safety Regulations, as set forth in 6 NYCRR § 673 and amended August 2009, apply to any owner of any impoundment, regardless of whether the impoundment meets the permit applicability criteria previously discussed (unless otherwise specified). In accordance with the general provisions of Section 673.3, any owner of an impoundment must operate and maintain the impoundment and all appurtenant works in a safe condition. The owner of any impoundment found to be in violation of this requirement is subject to the provisions of ECL 15-0507 and 15-0511.

In order to ensure the safe operation and maintenance of an impoundment, a written Inspection and Maintenance Plan is required under 6 NYCRR §673.6 for any impoundment that (1) requires a Protection of Waters Permit due to its height and storage capacity as previously discussed, (2) has been assigned a Hazard Classification of Class "B" or "C", or (3) impounds waters which pose a threat of personal injury, substantial property damage or substantial natural resources damage in the event of a failure, as determined by the Department. Such a plan shall be retained by the impoundment owner and updated as necessary, must be made available to the Department upon request, and must include:

- detailed descriptions of all procedures governing: the operation, monitoring, and inspection of the dam, including those governing the reading of instruments and the recording of instrument readings; the maintenance of the dam; and the preparation and circulation of notifications of deficiencies and potential deficiencies;

- a schedule for monitoring, inspections, and maintenance; and

- any other elements as determined by the Department based on its consideration of public safety and the specific characteristics of the dam and its location

Additionally, the owner of any impoundment assigned a Hazard Classification of Class “B” or “C” must, in accordance with 6 NYCRRR §673, prepare an Emergency Action Plan and annual updates thereof , provide a signed Annual Certification to the Department’s Dam Safety Section, conduct and report on Safety Inspections on a regular basis, and provide regular Engineering Assessments. Furthermore, all impoundment structures are subject to the Recordkeeping and Response to Request for Records provision of 6 NYCRR.

All impoundment structures, regardless of assigned Hazard Classification or permitting requirements, are subject to field inspections by the Department at its discretion and without prior notice. During such an inspection, the Department may document existing conditions through the use of photographs or videos without limitation. Based on the Field Inspection, the Department may create a Field Inspection Report and, if such a report is created for an impoundment with a Class “B” or “C” Hazard Classification, the Department will provide a copy of the report to the chief executive officer of the municipality or municipalities in which the impoundment is located.

To further ensure the safe operation and maintenance of all impoundments, 6 NYCRR §673.17 allows the Department to direct an impoundment owner to conduct studies, investigations and analyses necessary to evaluate the safety of the impoundment, or to remove, reconstruct or repair the impoundment within a reasonable time and in a manner specified by the Department.

5.8 Hydraulic Fracturing Design

Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected. In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures.[49] After the procedure is actually performed, the data gathered can be used to

[49] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer.* p. 57.

optimize future treatments.[50] Data to define the extent and orientation of fracturing may be gathered during fracture treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging.[51,52] ICF International, under contract to NYSERDA to provide research assistance for this document, notes that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models.[53] Comparison of production pressure and flow-rate analysis to pre-fracture modeling is a more common method for evaluating the results of a hydraulic fracturing procedure.[54]

The objective in any hydraulic fracturing procedure is to limit fractures to the target formation. Excessive fracturing is undesirable from a cost standpoint because of the expense associated with unnecessary use of time and materials.[55] Economics would dictate limiting the use of water, additives and proppants, as well as the need for fluid storage and handling equipment, to what is needed to treat the target formation.[56] In addition, if adjacent rock formations contain water, then fracturing into them would bring water into the reservoir formation and the well. This could result in added costs to handle produced water, or could result in loss of economic hydrocarbon production from the well.[57]

5.8.1 Fracture Development

ICF reviewed how hydraulic fracturing is affected by the rock's natural compressive stresses.[58] The dimensions of a solid material are controlled by major, intermediate and minor principal stresses within the material. In rock layers in their natural setting, these stresses are vertical and

---

[50] Ibid.

[51] Ibid.

[52] ICF, 2009., pp. 5-6.

[53] Ibid., p. 6.

[54] Ibid., pp. 6-8.

[55] GWPC, 2009a., p. 58.

[56] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic IES: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679., p. 14.

[57] GWPC, 2009a.. p. 58.

[58] ICF, 2009., pp. 14-15.

horizontal. Vertical stress increases with the thickness of overlying rock and exerts pressure on a rock formation to compress it vertically and expand it laterally. However, because rock layers are near infinite in horizontal extent relative to their thickness, lateral expansion is constrained by the pressure of the horizontally adjacent rock mass.[59]

Rock stresses may decrease over geologic time as a result of erosion acting to decrease vertical rock thickness. Horizontal stress decreases more slowly than vertical stress, so rock layers that are closer to the surface have a higher ratio of horizontal stress to vertical stress.[60]

Fractures form perpendicular to the direction of least stress. If the minor principal stress is horizontal, fractures will be vertical. The vertical fractures would then propagate horizontally in the direction of the major and intermediate principal stresses.[61]

ICF notes that the initial stress field created during deposition and uniform erosion may become more complex as a result of geologic processes such as non-uniform erosion, folding and uplift. These processes result in topographic features that create differential stresses, which tend to die out at depths approximating the scale of the topographic features.[62] ICF – citing PTTC, 2006 – concludes that: "In the Appalachian Basin, the stress state would be expected to lead to predominantly vertical fractures below about 2500 feet, with a tendency towards horizontal fractures at shallower depths."[63]

5.8.2 Methods for Limiting Fracture Growth

ICF reports that, despite ongoing laboratory and field experimentation, the mechanisms that limit vertical fracture growth are not completely understood.[64] Pre-treatment modeling, as discussed

[59] Ibid.

[60] Ibid.

[61] Ibid.

[62] Ibid.

[63] Ibid.

[64] Ibid., p. 16

above, is one tool for designing fracture treatments based on projected fracture behavior. Other control techniques identified by ICF include:[65]

- Use of a friction reducer, which helps to limit fracture height by reducing pumping loss within fractures, thereby maintaining higher fluid pressure at the fracture tip;
- Measuring fracture growth in real time by microseismic analysis, allowing the fracturing process to be stopped upon achieving the desired fracturing extent; and
- Reducing the length of wellbore fractured in each stage of the procedure, thereby focusing the applied pressure and proppant placement, and allowing for modifications to the procedure in subsequent stages based on monitoring the results of each stage.

5.8.3 Hydraulic Fracturing Design – Summary

ICF provided the following summary of the current state of hydraulic fracturing design to contain induced fractures in the target formation:

> Hydraulic fracturing analysis, design, and field practices have advanced dramatically in the last quarter century. Materials and techniques are constantly evolving to increase the efficiency of the fracturing process and increase reservoir production. Analytical techniques to predict fracture development, although still imperfect, provide better estimates of the fracturing results. Perhaps most significantly, fracture monitoring techniques are now available that provide confirmation of the extent of fracturing, allowing refinement of the procedures for subsequent stimulation activities to confine the fractures to the desired production zone. [66]

Photo 5.23 shows personnel monitoring a hydraulic fracturing procedure.

[65] Ibid., p.17

[66] Ibid., p. 19

Photo 5.23 Personnel monitoring a hydraulic fracturing procedure. Source: Fortuna Energy.

5.9 Hydraulic Fracturing Procedure

The fracturing procedure involves the controlled use of water and chemical additives, pumped under pressure into the cased and cemented wellbore. Composition, purpose, transportation, storage and handling of additives are addressed in previous sections of this document. Water and fluid management, including source, transportation, storage and disposition, are also discussed elsewhere in this document. Potential impacts, mitigation measures and the permit process are addressed in Chapters 6, 7 and 8. The discussion in this section describes only the specific physical procedure of high-volume hydraulic fracturing. Except where other references are specifically noted, operational details are derived from permit applications on file with the Department's Division of Mineral Resources and responses to the Department's information requests provided by several operators and service companies about their planned operations in New York.

Hydraulic fracturing occurs after the well is cased and cemented to protect fresh water zones and isolate the target hydrocarbon-bearing zone, and after the drilling rig and its associated equipment are removed. There will be at least two strings of cemented casing in the well during fracturing operations. The outer string (i.e., surface casing) extends below fresh ground water and would have been cemented to the surface before the well was drilled deeper. The inner string (i.e., production casing) typically extends from the ground surface to the toe of the horizontal well. Depending on the depth of the well and local geological conditions, there may be one or more intermediate casing strings between the surface and production strings. The inner production casing is the only casing string that will experience the high pressures associated with the fracturing treatment.[67] Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch to 10,000 pounds per square inch, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.

Before perforating the casing and pumping fracturing fluid into the well, the operator pumps fresh water or drilling mud to test the production casing. Test pumping is performed to at least the maximum anticipated treatment pressure, which is maintained for a period of time while the operator monitors pressure gauges. The purpose of this test is to verify, prior to pumping fracturing fluid, that the casing will successfully hold pressure and contain the treatment. Test pressure may exceed the maximum anticipated treatment pressure, but must remain below the casing's internal yield pressure.

The last step prior to fracturing is installation of a wellhead (referred to as a "frac tree") that is designed and pressure-rated specifically for the fracturing operation. Photo 5.24 depicts a frac tree that is pressure-rated for 10,000 pounds per square inch. Flowback equipment, including pipes, manifolds, a gas-water separator and tanks are connected to the frac tree and the system is pressure tested again.

[67] For more details on wellbore casing and cement: see Appendix 8 for current casing and cementing practices required for all wells in New York, Appendix 9 for additional permit conditions for wells drilled within the mapped areas of primary and principal aquifers, and Chapter 7 and Appendix 10 for proposed new permit conditions to address high-volume hydraulic fracturing.

Photo 5.24 - Three Fortuna Energy wells being prepared for hydraulic fracturing, with 10,000 psi well head and goat head attached to lines. Troy PA. Source: NYS DEC 2009

The hydraulic fracturing process itself is conducted in stages by successively isolating, perforating and fracturing portions of the horizontal wellbore starting with the far end, or toe. Reasons for conducting the operation in stages are to maintain sufficient pressure to fracture the entire length of the wellbore,[68] to achieve better control of fracture placement and to allow changes from stage to stage to accommodate varying geological conditions along the wellbore if necessary.[69] The length of wellbore treated in each stage will vary based on site-specific geology and the characteristics of the well itself, but may typically be 300 to 500 feet. In that case, the multi-stage fracturing operation for a 4,000 foot lateral would consist of eight to 13 fracturing stages. Each stage may require 300,000 to 600,000 gallons of water, so that the entire multi-stage fracturing operation for a single well would require 2.4 million to 7.8 million gallons

[68] GPWC, 2009a. *Modern Shale Gas Development in the United States: A Primer.*, p. 58

[69] Ibid.

of water.[70] More or less water may be used depending on local conditions, evolution in fracturing technology, or other factors which influence the operator's and service company's decisions.

The entire multi-stage fracturing operation for a single horizontal well typically takes two to five days, but may take longer for longer lateral wellbores, for many-stage jobs or if unexpected delays occur. Not all of this time is spent actually pumping fluid under pressure, as intervals are required between stages for preparing the hole and equipment for the next stage. Pumping rate may be as high as 1,260 to 3,000 gallons per minute.[71,72] At these rates, all the stages in the largest volume fracturing job described in the previous paragraph would require between approximately 40 and 100 hours of pumping.

The time spent pumping is the only time, except for when the well is shut-in, that wellbore pressure exceeds pressure in the surrounding rocks. Therefore, the hours spent pumping is the only time that fluid in fractures and in the rocks surrounding the fractures would move away from the wellbore instead of towards it. ICF International, under contract to NYSERDA, estimated the maximum rate of seepage in strata lying above the target Marcellus zone. Under most conditions evaluated by ICF, the seepage rate would be substantially less than 10 feet per day, or 5 inches per hour of pumping time. [73] More information about ICF's analysis is provided below in Section 5.11 and in Appendix 11.

Within each fracturing stage is a series of sub-stages, or steps.[74, 75] The first step is typically an acid treatment, which may also involve corrosion inhibitors and iron controls. Acid cleans the near-wellbore area accessed through the perforated casing and cement, while the other additives

---

[70] Applications on file with the Department propose volumes on the lower end of this range. The higher end of the range is based on GWPC (2009a), pp. 58-59, where an example of a single-stage Marcellus frac treatment using 578,000 gallons of fluid is presented. Stage lengths used in the above calculation (300 – 500 feet) were provided by Fortuna Energy and Chesapeake Energy in presentations to Department staff during field tours of operations in the northern tier of Pennsylvania.

[71] ICF International, 2009, p. 3

[72] GPWC, 2009a. *Modern Shale Gas Development in the United States: A Primer.*, p. 59

[73] ICF International, 2009, pp. 27-28

[74] URS Corporation, 2009. *A Survey of a Few Water Resources Issues Associated With Gas Production in the Marcellus Shale.*, p. 2-12

[75] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer,* pp. 58-60.

that may be used in this phase reduce rust formation and prevent precipitation of metal oxides that could plug the shale. The acid treatment is followed by the "slickwater pad," comprised primarily of water and a friction-reducing agent which helps optimize the pumping rate. Fractures form during this stage when the fluid pressure exceeds the minimum normal stress in the rock mass plus whatever minimal tensile stress exists.[76] The fractures are filled with fluid, and as the fracture width grows, more fluid must be pumped at the same or greater pressure to maintain and propagate the fractures.[77] As proppant is added, other additives such as a gelling agent and crosslinker may be used to increase viscosity and improve the fluid's capacity to carry proppant. Fine-grained proppant is added first, and carried deepest into the newly induced fractures, followed by coarser-grained proppant. Breakers may be used to reduce the fluid viscosity and help release the proppant into the fractures. Biocides may also be added to inhibit the growth of bacteria that could interfere with the process and produce hydrogen sulfide. Clay stabilizers may be used to prevent swelling and migration of formation clays. The final step is a freshwater flush to clean out the wellbore and equipment.

Photos 5.25 – 5.26 depict wellsites during hydraulic fracturing operations, labeled to identify the equipment that is present onsite.

[76] ICF, 2009. p. 16

[77] Ibid.


1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19

Photo 5.25 (Above) Hydraulic Fracturing Operation

These photos show a hydraulic fracturing operation at a Fortuna Energy multi-well site in Troy PA. At the time the photos were taken, preparations for fracturing were underway but fracturing had not yet occurred for any of the wells.

Hydraulic Fracturing Operation Equipment

1. Well head and frac tree with 'Goat Head' (See Figure 5.x for more detail)
2. Flow line (for flowback & testing)
3. Sand separator for flowback
4. Flowback tanks
5. Line heaters
6. Flare stack
7. Pump trucks
8. Sand hogs
9. Sand trucks
10. Acid trucks
11. Frac additive trucks
12. Blender
13. Frac control and monitoring center
14. Fresh water impoundment
15. Fresh water supply pipeline
16. Extra tanks

Production equipment

17. Line heaters
18. Separator-meter skid
19. Production manifold

Photo 5.26 Fortuna multi-well pad after hydraulic fracturing of three wells and removal of most hydraulic fracturing equipment. Production equipment for wells on right side of photo. Source: Fortuna Energy, July, 2009.

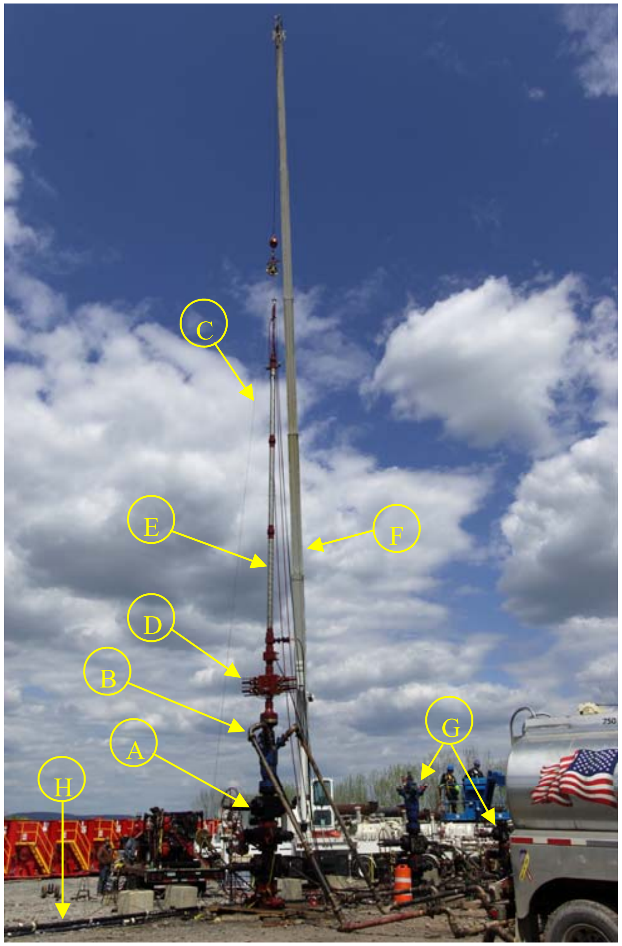


Photo 5.27 Wellhead and Frac Equipment

A. Well head and frac tree (valves)
B. Goat Head (for frac flow connections)
C. Wireline (used to convey equipment into wellbore)
D. Wireline Blow Out Preventer
E. Wireline lubricator
F. Crane to support wireline equipment
G. Additional wells
H. Flow line (for flowback & testing)

5.10 Re-fracturing

Developers may decide to re-fracture a well to extend its economic life whenever the production rate declines significantly below past production rates or below the estimated reservoir potential.[78] According to ICF International, fractured Barnett shale wells generally would benefit from re-fracturing within five years of completion, but the time between fracture stimulations can be less than one year or greater than ten years.[79] However, Marcellus operators with whom the Department has discussed this question have stated their expectation that re-fracturing will be a rare event.

It is too early in the development of shale reservoirs in New York to predict the frequency with which re-fracturing of horizontal wells, using the slickwater method, may occur. ICF provided some general information on the topic of re-fracturing.

Wells may be re-fractured multiple times, may be fractured along sections of the wellbore that were not previously fractured, and may be subject to variations from the original fracturing technique.[80] The Department notes that while one stated reason to re-fracture may be to treat sections of the wellbore that were not previously fractured, this scenario does not seem applicable to Marcellus Shale development. Current practice in the Marcellus Shale in the northern tier of Pennsylvania is to treat the entire lateral wellbore, in stages, during the initial procedure.

Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary.[81] Re-fracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.[82] Changes in formation stresses due to the

[78] ICF International, 2009, p. 18

[79] Ibid.

[80] Ibid., p. 17

[81] Ibid.

[82] Ibid.

reduction in pressure from production can sometimes cause new fractures to propagate at a different orientation than the original fractures, further extending the fracture zone. [83]

Factors that influence the decision to re-fracture include past well production rates, experience with other wells in the same formation, the costs of re-fracturing, and the current price for gas.[84] Factors in addition to the costs of re-fracturing and the market price for gas that determine cost-effectiveness include the characteristics of the geologic formation and the time value of money.[85]

Regardless of how often it occurs, if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure. The rate of subsurface fluid movement during pumping operations would be the same as discussed above. It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore. Therefore, total fluid movement away from the wellbore as a result of repeated fracture treatments would be less than the sum of the distance moved during each fracture treatment.

5.11 Fluid Return

After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses. The well is "cleaned up" by allowing water and excess proppant to flow up through the wellbore to the surface. Both the process and the returned water are commonly referred to as "flowback."

5.11.1 Flowback Water Recovery

Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on Section 5.9's pumped fluid estimate of 2.4 million to 7.8 million gallons. This volume is generally recovered within two to eight weeks, then the well's water production rate sharply declines and levels off at a few barrels per day for the remainder of its producing life. URS Corporation, under contract to

---

[83] Ibid., pp. 17-18

[84] Ibid., p. 18

[85] Ibid.

NYSERDA, reported that limited time-series data indicates that approximately 60 percent of the total flowback occurs in the first four days after fracturing.[86]

5.11.1.1 Subsurface Mobility of Fracturing Fluids

Reference is made in Section 5.9 to ICF International's calculations of the rate at which fracturing fluids could move away from the wellbore through fractures and the rock matrix during pumping operations. Appendix 11 provides ICF's full discussion of the principles governing potential fracture fluid flow. ICF's conclusion is that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers." [87] Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are vertically separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of fracturing fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow from the aquifer to the production zone as pressures decline in the reservoir during production.

5.11.2 Flowback Water Handling at the Wellsite

The GEIS describes (a) unchecked flow through a valve into a lined pit, (b) flow through a choke into the lined pit, and (c) flow to tanks. Operators have reported flowback rates of 60 – 130

[86] URS, p. 3-2

[87] ICF International, 2009., p. 34.

gallons per minute, without pumping, after high-volume hydraulic fracturing of the Marcellus in the northern tier of Pennsylvania.

An onsite lined reserve pit, if one is used, could be internally segmented to hold flowback water separately from drilling fluid and cuttings, or a separate pit could be constructed specifically for flowback water. In either case, existing regulations require fluid associated with each well to be removed within 45 days of the cessation of operations, unless the operator has submitted a plan to use the fluids in subsequent operations and the Department has inspected and approved the pit.[88] Operators have indicated plans to re-use as much flowback water as possible for future fracturing operations, diluting it with freshwater and applying other treatment methods if necessary to meet the usability characteristics described in Section 5.7. Operators could, therefore, propose to retain flowback water in an on-site lined pit longer for longer than 45 days, until the next well or well pad is ready for fracturing operations.

Dimensions of an on-site pit would vary based on topography and the configuration of the well pad. One operator reports a typical pit volume of 750,000 gallons. Pennsylvania limits wellsite impoundments to 250,000 gallons for a single or connected network of pits, and limits total volume of all well site pits on one tract or related tracts of land to 500,000 gallons.[89] The high rate and potentially high volume of flowback water generally requires additional temporary storage tanks to be staged onsite even if an onsite lined pit is used.

As discussed in Chapter 7, the Department proposes to require tanks for on-site (i.e., well pad) handling of flowback water unless additional compositional data is collected and provided on a site-specific basis to support an alternate proposal.

5.11.3 Flowback Water Characteristics

The following description of flowback water characteristics was provided by URS Corporation, under contract to NYSERDA. This discussion is based on a limited number of analyses from out-of-state operations, without corresponding complete compositional information on the fracturing additives that were used at the source wells. The Department did not direct or oversee

[88] 6 NYCRR 554.1(c)(3). For permitting and SEQRA purposes, well stimulation is part of the action of drilling the well.

[89] Alpha, 2009, p. 2-5.

sample collection or analysis efforts. Most fracturing fluid components are not included as analytes in standard chemical scans of flowback samples that were provided to DEC, so little information is available to document whether and at what concentrations most fracturing chemicals occur in flowback water.

The Department anticipates that, by the time the final SGEIS is published, additional data and analyses will be made public by the Marcellus Shale Committee and the Appalachian Shale Water Conservation and Management Committee. Because of the limited availability at this time of flowback water quality data, conservative and strict mitigation measures regarding flowback water handling are proposed in Chapter 7, and additional data will be required for alternative proposals.

Flowback fluids include the fracturing fluids pumped into the well, which consists of water and additives discussed in Section 5.4; any new compounds that may have formed due to reactions between additives; and substances mobilized from within the shale formation due to the fracturing operation. Some portion of the proppant may return to the surface with flowback, but operators strive to minimize proppant return: the ultimate goal of hydraulic fracturing is to convey and deposit the proppant within fractures in the shale to maximize gas flow.

Marcellus Shale is of marine origin and, therefore, contains high levels of salt. This is further evidenced by analytical results of flowback provided to NYSDEC by well operators and service companies from operations based in Pennsylvania. The results vary in level of detail. Some companies provided analytical results for one day for several wells, while other companies provided several analytical results for different days of the same well (i.e. time-series). Flowback parameters were organized by Chemicals Abstract Service (CAS) number, whenever available.

Typical classes of parameters present in flowback fluid are:

- Dissolved Solids (chlorides, sulfates, and calcium)
- Metals (calcium, magnesium, barium, strontium)
- Suspended solids
- Mineral scales (calcium carbonate and barium sulfate)

- Bacteria - acid producing bacteria and sulfate reducing bacteria
- Friction Reducers
- Iron solids (iron oxide and iron sulfide)
- Dispersed clay fines, colloids & silts
- Acid Gases (carbon dioxide, hydrogen sulfide)

A list of parameters detected in a limited set of analytical results is provided in Table 5.8. Typical concentrations of parameters other than radionuclides, based on limited data from PA and WV, are provided in Table 5.9. Radionuclides are separately discussed and tabulated in Section 5.11.3.3.

Table 5-8 - Parameters present in a limited set of flowback analytical results

CAS#	Parameters Detected in Flowback from PA and WV Operations
00056-57-5	4-Nitroquinoline-1 -oxide
00067-64-1	Acetone
07439-90-5	Aluminum
07440-36-0	Antimony
07664-41-7	Aqueous ammonia
07440-38-2	Arsenic
07440-39-3	Barium
00071-43-2	Benzene
00117-81-7	Bis(2-ethylhexyl)phthalate
07440-42-8	Boron
24959-67-9	Bromide
00075-25-2	Bromoform
07440-43-9	Cadmium
07440-70-2	Calcium
00124-48-1	Chlorodibromomethane
07440-47-3	Chromium
07440-48-4	Cobalt
07440-50-8	Copper
00057-12-5	Cyanide
00075-27-4	Dichlorobromomethane
00100-41-4	Ethyl Benzene
16984-48-8	Fluoride
07439-89-6	Iron
07439-92-1	Lead
07439-93-2	Lithium
07439-95-4	Magnesium
07439-96-5	Manganese

CAS#	Parameters Detected in Flowback from PA and WV Operations
00074-83-9	Methyl Bromide
00074-87-3	Methyl Chloride
07439-98-7	Molybdenum
00091-20-3	Naphthalene
07440-02-0	Nickel
00108-95-2	Phenol
57723-14-0	Phosphorus
07440-09-7	Potassium
07782-49-2	Selenium
07440-22-4	Silver
07440-23-5	Sodium
07440-24-6	Strontium
14808-79-8	Sulfate
14265-45-3	Sulfite
00127-18-4	Tetrachloroethylene
07440-28-0	Thallium
07440-32-6	Titanium
00108-88-3	Toluene
07440-66-6	Zinc

	Parameters Detected in Flowback from PA and WV Operations (cont'd)
	1,1,1-Trifluorotoluene
	1,4-Dichlorobutane
	2,4,6-Tribromophenol
	2,5-Dibromotoluene
	2-Fluorobiphenyl
	2-Fluorophenol
	4-Terphenyl-d14
	Alkalinity
	Alkalinity, Carbonate, as CaCO3
	Alpha radiation
	Aluminum, Dissolved
	Barium Strontium P.S.
	Barium, Dissolved
	Beta radiation
	Bicarbonates
	Biochemical Oxygen Demand
	Cadmium, Dissolved
	Calcium, Dissolved
	Chemical Oxygen Demand
	Chloride
	Chromium (VI)
	Chromium (VI), dissolved
	Chromium, (III)
	Chromium, Dissolved
	Cobalt, dissolved

Parameters Detected in Flowback from PA and WV Operations (cont'd)
Color
Conductivity
Hardness
Iron, Dissolved
Lithium, Dissolved
Magnesium, Dissolved
Manganese, Dissolved
Nickel, Dissolved
Nitrobenzene-d5
Nitrogen, Total as N
Oil and Grease
o-Terphenyl
Petroleum hydrocarbons
pH
Phenols
Potassium, Dissolved
Radium
Radium 226
Radium 228
Salt
Scale Inhibitor
Selenium, Dissolved
Silver, Dissolved
Sodium, Dissolved
Strontium, Dissolved
Sulfide
Surfactants
Total Alkalinity
Total Dissolved Solids
Total Kjeldahl Nitrogen
Total Organic Carbon
Total Suspended Solids
Xylenes
Zinc, Dissolved
Zirconium

Note that the parameters listed in Table 5.6 are based on the composition of additives used or proposed for use in New York. Parameters listed in Tables 5.8 and 5.9 are based on analytical results of flowback from operations in Pennsylvania or West Virginia. All information is for operations in the Marcellus shale.

Some parameters found in analytical results are due to additives used in fracturing, some are due to reactions between different additives, while others may have been mobilized from within the formation; still other parameters may have been contributed from more than one source. Further study would be required to identify the specific origin of each parameter.

Table 5-9 - Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[90]

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	1,4-Dichlorobutane	1	1	198	198	198	%REC
	2,4,6-Tribromophenol[91]	1	1	101	101	101	%REC
	2-Fluorobiphenyl[92]	1	1	71	71	71	%REC
	2-Fluorophenol[93]	1	1	72.3	72.3	72.3	%REC
00056-57-5	4-Nitroquinoline-1 -oxide	24	24	1422	13908	48336	mg/L
	4-Terphenyl-d14 [94]	1	1	44.8	44.8	44.8	%REC
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Alkalinity, Carbonate, as CaCO3	31	9	4.9	91	117	mg/L
07439-90-5	Aluminum	29	3	0.08	0.09	1.2	mg/L
07440-36-0	Antimony	29	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	28	25	12.4	58.1	382	mg/L
07440-38-2	Arsenic	29	2	0.09	0.1065	0.123	mg/L
07440-39-3	Barium	34	34	0.553	661.5	15700	mg/L
00071-43-2	Benzene	29	14	15.7	479.5	1950	µg/L
	Bicarbonates [95]	24	24	0	564.5	1708	mg/L
	Biochemical Oxygen Demand	29	28	3	274.5	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	23	2	10.3	15.9	21.5	µg/L
07440-42-8	Boron	26	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	6	6	11.3	616	3070	mg/L

90 Table 5.9 was provided by URS Corporation (based on data submitted to DEC) with the following note: Information presented is based on limited data from Pennsylvania and West Virginia. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. In addition, the raw data for these tables came from several sources, with likely varying degrees of reliability. Also, the analytical methods used were not all the same for given parameters. Sometimes laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days soon after the well is fractured. This data does not control for any of these variables.

91 Regulated under phenols.

92 Regulated under phenols.

93 Regulated under phenols.

94 Regulated under phenols.

95 Regulated under alkalinity.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
00075-25-2	Bromoform	29	2	34.8	36.65	38.5	μg/L
07440-43-9	Cadmium	29	5	0.009	0.032	1.2	mg/L
07440-70-2	Calcium	55	52	29.9	5198	34000	mg/L
	Chemical Oxygen Demand	29	29	1480	5500	31900	mg/L
	Chloride	58	58	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	29	2	3.28	3.67	4.06	μg/L
07440-47-3	Chromium	29	3	0.122	5	5.9	mg/L
07440-48-4	Cobalt	25	4	0.03	0.3975	0.58	mg/L
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	29	4	0.01	0.035	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	μg/L
00100-41-4	Ethyl Benzene	29	14	3.3	53.6	164	μg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	58	34	0	47.9	810	mg/L
07439-92-1	Lead	29	2	0.02	0.24	0.46	mg/L
	Lithium	25	4	34.4	55.75	161	mg/L
07439-95-4	Magnesium	58	46	9	563	3190	mg/L
07439-96-5	Manganese	29	15	0.292	2.18	14.5	mg/L
00074-83-9	Methyl Bromide	29	1	2.04	2.04	2.04	μg/L
00074-87-3	Methyl Chloride	29	1	15.6	15.6	15.6	μg/L
07439-98-7	Molybdenum	25	3	0.16	0.72	1.08	mg/L
00091-20-3	Naphthalene	26	1	11.3	11.3	11.3	μg/L
07440-02-0	Nickel	29	6	0.01	0.0465	0.137	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	25	9	5	17	1470	mg/L
	o-Terphenyl [96]	1	1	91.9	91.9	91.9	%Rec
	pH	56	56	1	6.2	8	S.U.
00108-95-2	Phenol	23	1	459	459	459	μg/L
	Phenols	25	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L
07440-09-7	Potassium	31	13	59	206	7810	mg/L
07782-49-2	Selenium	29	1	0.058	0.058	0.058	mg/L
07440-22-4	Silver	29	3	0.129	0.204	6.3	mg/L
07440-23-5	Sodium	31	28	83.1	19650	96700	mg/L
07440-24-6	Strontium	30	27	0.501	821	5841	mg/L
14808-79-8	Sulfate (as SO4)	58	45	0	3	1270	mg/L
	Sulfide (as S)	3	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO3)	3	3	2.56	64	64	mg/L
	Surfactants [97]	3	3	0.2	0.22	0.61	mg/L
00127-18-4	Tetrachloroethylene	29	1	5.01	5.01	5.01	μg/L
07440-28-0	Thallium	29	1	0.1	0.1	0.1	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	29	15	2.3	833	3190	μg/L
	Total Dissolved Solids	58	58	1530	93200	337000	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [98]	23	23	69.2	449	1080	mg/L

[96] Regulated under phenols.

[97] Regulated under foaming agents.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	Total Suspended Solids	29	29	30.6	146	1910	mg/L
	Xylenes	22	14	16	487	2670	µg/L
07440-66-6	Zinc	29	6	0.028	0.048	0.09	mg/L

5.11.3.1 Temporal Trends in Flowback Water Composition

The composition of flowback water changes with time, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water taken at different times indicate that:

- The concentrations of total dissolved solids (TDS), chloride, and barium increase;
- The levels of radioactivity increase[99],
- Calcium and magnesium hardness increases;
- Iron concentrations increase, unless iron-controlling additives are used;
- Sulfate levels decrease;
- Alkalinity levels decrease, likely due to use of acid; and
- Concentrations of metals increase[100].

Available literature cited by URS corroborates the above summary regarding the changes in composition with time for TDS, chlorides, and barium. Fracturing fluids pumped into the well, and mobilization of materials within the shale may be contributing to the changes seen in hardness, sulfate, and metals. The specific changes would likely depend on the shale formation, fracturing fluids used and fracture operations control.

[98] Regulated via BOD, COD and the different classes/compounds of organic carbon.

[99] Limited data from vertical well operations in NY have reported the following ranges of radioactivity: alpha 22.41 – 18950 pCi/L; beta 9.68 – 7445 pCi/L; Radium^{226} 2.58 - 33 pCi/L.

[100] Metals such as aluminum, antimony, arsenic, barium, boron, cadmium, calcium, cobalt, copper, iron, lead, lithium, magnesium, manganese, molybdenum, nickel, potassium, radium, selenium, silver, sodium, strontium, thallium, titanium, and zinc have been reported in flowback analyses. It is important to note that each well did not report the presence of all these metals.

5.11.3.2 NYSDOH Chemical Categories

The GEIS identified high total dissolved solids (TDS), chlorides, surfactants, gelling agents and metals as the components of greatest concern in spent gel and foam fracturing fluids (i.e., flowback). Slickwater fracturing fluids proposed for Marcellus well stimulation may contain other additives such as corrosion inhibitors, friction reducers and microbiocides, in addition to the contaminants of concern identified in the GEIS. Most fracturing fluid additives used in a well can be expected in the flowback water, although some are expected to be consumed in the well (e.g., strong acids) or react during the fracturing process to form different products (e.g., polymer precursors).

At the DEC's request, NYSDOH provided the following additional discussion of flowback water relative to the chemical classes described in Section 5.4.3.1. DOH reviewed the same information that was discussed by URS, and noted the same data limitations.

Aromatic Hydrocarbons

Flowback analyses include some results for BTEX. In one set of the 16 flowback samples from wells in PA and NYS analyzed for these 4 compounds (including xylenes as total xylene), one sample contained benzene, toluene and xylene (total) ranging from 15 to 33 micrograms per liter (μg/L). In another set of 20 samples from wells in WV and PA, 13 had detectable amounts of benzene and 14 detectable amounts of other BTEX compounds. BTEX concentrations were higher in these samples compared to the first set (overall range of detected levels from 2.3 to 3190 μg/L). All of the higher BTEX concentrations came from wells in WV where a friction reducer product containing 10- 30% petroleum distillates was one of the highest volume fracturing additives.

Glycols

One flowback sample was analyzed for 5 different glycols. No glycols were detected in this sample, but the detection limits were relatively high (20,000 μg/L).

Glycol Ethers

Flowback samples were not analyzed for glycol ethers.

Alcohols

Flowback samples were not analyzed for alcohols.

Amides

One flowback sample included analysis for acrylamide, which was not detected (< 1.5 µg/L). Sixteen flowback samples were analyzed for sodium polyacrylate as an indicator of a scale inhibitor that included a polymer composed of both acrylic acid and acrylamide. All samples contained sodium polyacrylate at levels ranging from 450 to 1350 mg/L (1 mg/L = 1000 µg/L). Since this analysis targeted a polymerized reaction product and not the individual monomers, it is unclear from these data how much of the monomers, if any, occurred in the flowback.

Amines

Flowback samples were not analyzed for amines.

Nineteen flowback samples from wells in PA and WV were analyzed for 3 nitrosamines, and none were detected in any samples (most detection limits were < 10 µg/L; one set was < 96.2 µg/L and one set was < 1020 µg/L).

Trihalomethanes

Bromoform, chloroform, bromodichloromethane and chlorodibromomethane are collectively referred to as trihalomethanes (THMs). These are not listed as components of any hydraulic fracturing products reviewed by DOH. However, THMs were reported in flowback fluid samples from Marcellus wells in West Virginia. THMs commonly occur as byproducts of drinking water disinfection when disinfectants react with naturally occurring organic matter and salts in the water. Chloroform, bromodichloromethane and dibromochloromethane cause cancer in laboratory animals exposed to high levels over their lifetimes. Chloroform, bromodichloromethane and dibromochloromethane are also known to cause non-cancer effects in laboratory animals after high levels of exposure, primarily on the liver, kidney, nervous system and on their ability to bear healthy offspring.

THMs were only detected in flowback samples collected immediately following fracturing from two sets of WV flowback data. THMs could have been present in the source water used for fracturing these wells or could have been produced during fracturing if chlorine- or bromine-containing fracturing additives were used. Detected levels were 2.24 µg/L in one sample for bromodichloromethane, 3.67 µg/L in one sample for chlorodibromomethane and 34.8 to 38.5 µg/L in two samples for bromoform. Chloroform was not detected in these samples (all either <1 or <10 µg/L).

Organic Acids, Salts and Related Chemicals

Flowback samples were not analyzed for organic acids or related chemicals.

Minerals, Metals, Other Characteristics (e.g., TDS)

Inorganic chemicals are constituents of fracturing fluid products and also occur in flowback water and production brines when they are dissolved from rock formations during well development and production. Based on Marcellus flowback samples (primarily from wells in WV and PA), minerals and metals likely to be present in flowback fluid are similar to those found in production water from many NYS geological formations (e.g., GEIS, Table 15.4). The main constituents of concern are the same as those discussed in Chapter 9, Section H of the GEIS: chlorides, heavy metals and high total dissolved solids (TDS).

The discussion in the 1992 GEIS regarding these constituents of concern appears to be applicable to flowback water from hydraulically fractured Marcellus wells. Limited flowback sampling suggests mineral and metal content increases in samples collected later in the flowback process. Chloride and TDS levels in Marcellus late flowback samples are similar to levels from other formations discussed in the GEIS.

Microbiocides

Flowback samples were not analyzed for microbiocide chemicals.

Other Constituents

Formaldehyde was not detected (<1000 µg/L) in chemical analysis of three flowback samples from PA wells. Flowback samples were not analyzed for 1,4-Dioxane.

5.11.3.3 Naturally Occurring Radioactive Materials in Flowback Water

Several radiological parameters were detected in flowback samples, as shown in the following tabulations.

Table 5-10- Concentrations of NORM constituents based on limited samples from PA and WV.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
--	Gross Alpha	8	8	22.41	--	18,950	pCi/L
--	Gross Beta	8	8	62	--	7,445	pCi/L
7440-14-4	Total Alpha Radium	6	6	3.8	--	1,810	pCi/L
7440-14-4	Radium-226	3	3	2.58	--	33	pCi/L
7440-14-4	Radium-228	3	3	1.15	--	18.41	pCi/L

5.12 Flowback Water Treatment, Recycling and Reuse

Operators have expressed the objective of maximizing their reuse of flowback water for subsequent fracturing operations at the same well pad or other well pads. This involves dilution of the flowback water with fresh water or more sophisticated treatment options. Regardless of the treatment objective, whether for reuse or direct discharge, the three basic issues that need consideration when developing water treatment technologies are:[101]

1. Influent (i.e., flowback water) parameters and their concentrations
2. Parameters and their concentrations allowable in the effluent (i.e., in the reuse water)
3. Disposal of residuals

Untreated flowback water composition is discussed in Section 5.11.3. Table 5.10 summarizes allowable concentrations after treatment (and prior to potential additional dilution with fresh water).[102]

Table 5-11 - Maximum allowable water quality requirements for fracturing fluids, based on input from one expert panel on Barnett Shale

Constituent	Concentration
Chlorides	3,000 - 90,000 mg/l
Calcium	350 - 1,000 mg/l

[101] URS Corporation, 1990. p. 5-2

[102] URS Corporation, 1990, p. 5-3

Constituent	Concentration
Suspended Solids	< 50 mg/l
Entrained oil and soluble organics	< 25 mg/l
Bacteria	cells/100 ml < 100
Barium	Low levels

The following factors influence the decision to utilize on-site treatment and the selection of specific treatment options:[103]

Operational

- Flowback fluid characteristics, including scaling and fouling tendencies
- On-site space availability
- Processing capacity needed
- Solids concentration in flowback fluid, and solids reduction required
- Concentrations of hydrocarbons in flowback fluid, and targeted reduction in hydrocarbon[104]
- Species and levels of radioactivity in flowback
- Access to freshwater sources
- Targeted recovery rate
- Impact of treated water on efficacy of additives
- Availability of residuals disposal options

Cost

- Capital costs associated with treatment system

[103] Ibid.

[104] Liquid hydrocarbons have not been detected in all Marcellus Shale gas analyses.

- Transportation costs associated with freshwater
- Increase or decrease in fluid additives from using treated flowback fluid

Environmental

- On-site topography
- Density of neighboring population
- Proximity to freshwater sources
- Other demands on freshwater in the vicinity
- Regulatory environment

5.12.1 Physical and Chemical Separation[105]

Some form of physical and/or chemical separation will be required as a part of on-site treatment. Physical and chemical separation technologies typically focus on the removal of oil and grease[106] and suspended matter from flowback.

The physical separation technologies include hydrocyclones, filters, and centrifuges; the size of constituents in flowback fluid drives separation efficiency. Chemical separation utilizes coagulants and flocculants to break emulsions (dissolved oil) and to remove suspended particles.

Modular physical and chemical separation units have been used in the Barnett Shale and Powder River Basin.

5.12.2 Dilution

The dilution option involves blending minimally treated flowback with freshwater to make it usable for future fracturing operations. However, this methodology may be limited by the extent to which high concentrations of different parameters in flowback adversely affect the desired

---

[105] URS Corporation, 2009, p. 5-6.

[106] Oil and grease are not expected in the Marcellus.

fracturing fluid properties.[107] Concentrations of chlorides, calcium, magnesium, barium, carbonates, sulfates, solids and microbes in flowback water may be too high to use as-is. The demand for friction reducers increases when the chloride concentration increases; the demand for scale inhibitors increases when concentrations of calcium, magnesium, barium, carbonates, or sulfates increase; biocide requirements increase when the concentration of microbes increases. The current recycling practice of blending flowback with freshwater involves balancing the additional freshwater water needs with the additional additive needs. [108] As stated above, some form of physical and/or chemical separation is typically needed prior to recycling flowback.[109] Service companies and chemical suppliers may develop additive products that are more compatible with the aforementioned flowback water parameters.

URS suggests that compatibility mixing studies be performed prior to the actual blending of flowback water and freshwater in the field.[110] URS further reported that experts in the field suggest that flowback water and freshwater be evaluated multiple times during the year to assess potential seasonal variations and their impact on bacterial activity and water quality. Use of friction reducers, scale inhibitors, biocides, etc. would need to be modulated based on the composition and characteristics of the blend.[111]

5.12.2.1 Centralized Storage of Flowback Water for Dilution and Reuse

Operators may propose to store flowback water prior to or after dilution in the onsite lined pits or tanks discussed in Section 5.11.2, or in centralized facilities consisting of tanks or one or more engineered impoundments. Water would be moved to and from the centralized facilities by truck or pipeline. Operators have informed the Department that centralized impoundments constructed for this purpose would range in surface area from less than one acre to five acres, and would range in capacity from one to 16 million gallons. Depending on topography, such impoundments would serve well pads within up to a four-mile radius. Storage impoundments would be fenced, with locked gates, to restrict access of non-company personnel and wildlife. Cover systems may

[107] URS Corporation, 2009. p. 5-1

[108] URS Corporation, 2009. p. 5-2.

[109] Ibid.

[110] URS, p. 5-2

[111] URS, p. 5-2

be employed to further restrict access by birds and other wildlife. Operators describe plans to use dual liner systems with leak detection, along with piezometer wells on the perimeter of the impoundment. One operator who has used centralized flowback impoundments in another state reports the following typical design characteristics:

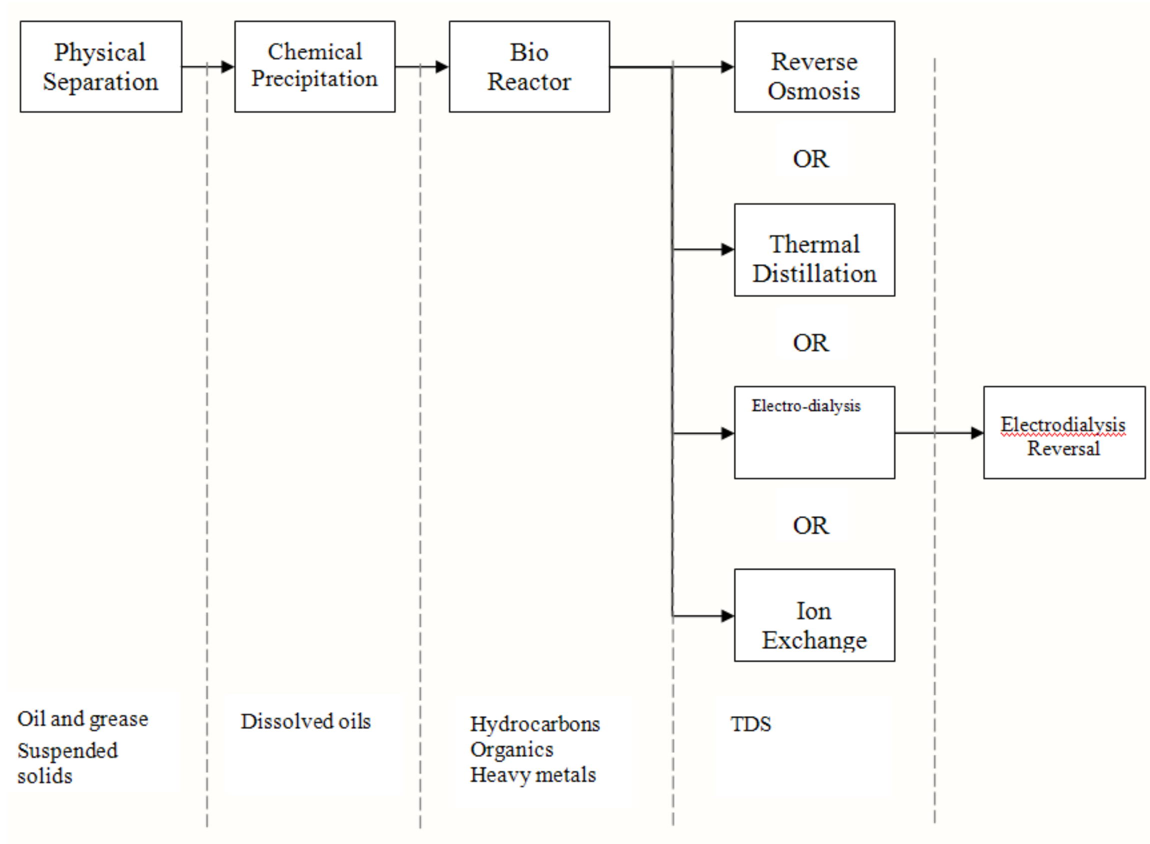
- A liner system with an upper (primary) 60-mil liner of high density polyethylene (HDPE) geomembrane and a lower (secondary) 40-mil liner of HDPE geomembrane with a geocomposite layer underneath.
- A geocomposite layer between the two geomembrane liners.
- A leak detection system installed in the interstitial space between the two liners within a trench placed below the impoundment at its lowest point of elevation.

5.12.2 Other On-Site Treatment Technologies[112]

One of the several on-site treatment technology configurations is illustrated in Figure 5.5.

[112] URS Corporation, 2009.

Figure 5-5 - One configuration of potential on-site treatment technologies.



5.12.2.1 Membranes / Reverse Osmosis

Membranes are an advanced form of filtration, and may be used to treat TDS in flowback. The technology allows water to pass through the membrane - the permeate - but the membrane blocks passage of suspended or dissolved particles larger than the membrane pore size. This method may be able to treat TDS concentrations up to approximately 30,000 mg/L, and produce water with TDS concentrations between 200 and 500 mg/L. This technology generates a residual - the concentrate - that would need proper disposal. The flowback water recovery rate for most membrane technologies is typically between 50-75 percent. Membrane performance may be impacted by scaling and/or microbiological fouling. Flowback water would likely require extensive pretreatment before it is sent through a membrane.

Reverse osmosis (RO) is a membrane technology that uses osmotic pressure on the membrane to provide passage of high-quality water.

Modular membrane technology units have been used in the Barnett Shale.

5.12.2.2 Thermal Distillation

Thermal distillation utilizes evaporation and crystallization techniques that integrate a multi-effect distillation column, and this technology may be used to treat flowback water with a large range of parameter concentrations. For example, thermal distillation may be able to treat TDS concentrations from 5,000 to over 150,000 mg/L, and produce water with TDS concentrations between 50 and 150 mg/L. The resulting residual salt would need appropriate disposal. This technology is resilient to fouling and scaling, but is energy intensive and has a large footprint.

Modular thermal distillation units have been used in the Barnett Shale.

5.12.2.3 Ion Exchange

Ion exchange units utilize different resins to preferentially remove certain ions. When treating flowback, the resin would be selected to preferentially remove sodium ions. The required resin volume and size of the ion exchange vessel would depend on the salt concentration and flowback volume treated.

The Higgins Loop is one version of ion exchange that has been successfully used in Midwest coal bed methane applications. The Higgins Loop uses a continuous countercurrent flow of flowback fluid and ion exchange resin. High sodium flowback fluid can be fed into the absorption chamber to exchange for hydrogen ions. The strong acid cation resin is advanced to the absorption chamber through a unique resin pulsing system.

Modular ion exchange units have been used in the Barnett Shale.

5.12.2.4 Electrodialysis

These treatment units are configured with alternating stacks of cation and anion membranes that allow passage of flowback fluid. The electric current applied to the stacks forces anions and cations to migrate in different directions.

Electrodialysis Reversal (EDR) is similar to electrodialysis, but its electric current polarity may be reversed as needed. This current reversal acts as a backwash cycle for the stacks which reduces scaling on membranes. EDR offers lower electricity usage than standard reverse osmosis systems and can potentially reduce salt concentrations in the treated water to less than 200 mg/L.

Table 5.12 compares EDR and RO by outlining key characteristics of both technologies.

Table 5-12 - Treatment capabilities of EDR and RO Systems

Criteria	EDR	RO
Acceptable influent TDS (mg/L)	400-3,000	100-15,000
Salt removal capacity	50-95%	90-99%
Water recovery rate	85-94%	50-75%
Allowable Influent Turbidity	Silt Density Index (SDI) < 12	SDI < 5
Operating Pressure	<50 psi	> 100 psi
Power Consumption	Lower for <2,500 mg/L TDS	Lower for >2,500 mg/L TDS
Typical Membrane Life	7-10 years	3-5 years

Modular electrodialysis units have been used in the Barnett Shale and Powder River Basin.

5.12.2.5 Ozone/Ultrasonic/Ultraviolet

These technologies are expected to oxidize and separate hydrocarbons, heavy metals, biological films and bacteria from flowback fluid. The microscopic air bubbles in supersaturated ozonated water and/or ultrasonic transducers cause oils and suspended solids to float.

5.12.3 Comparison of Potential On-Site Treatment Technologies

A comparison of performance characteristics associated with on-site treatment technologies is provided in Table 5.13.[113]

[113] URS Corporation, 2009, p. 5-8.

Table 5-13 - Summary of Characteristics of On-Site Flowback Water Treatment Technologies

Characteristics	Filtration	Ion Exchange	Reverse Osmosis	EDR	Thermal Distillation
Energy Cost	Low	Low	Moderate	High	High
Energy Usage vs. TDS	N/A	Low	Increase	High Increase	Independent
Applicable to	All Water types	All Water types	Moderate TDS	High TDS	High TDS
Plant / Unit size	Small / Modular	Small / Modular	Modular	Modular	Large
Microbiological Fouling	Possible	Possible	Possible	Low	N/A
Complexity of Technology	Easy	Easy	Moderate / High Maintenance	Regular Maintenance	Complex
Scaling Potential	Low	Low	High	Low	Low
Theoretical TDS Feed Limit (mg/L)	N/A	N/A	32,000	40,000	100,000+
Pretreatment Requirement	N/A	Filtration	Extensive	Filtration	Minimal
Final Water TDS	No impact	200-500 ppm	200-500 ppm	200-1000 ppm	< 10 mg/L
Recovery Rate (Feed TDS >20,000 mg/L)	N/A	N/A	30-50%	60-80%	75-85%

5.13 Waste Disposal

5.13.1 Cuttings from Mud Drilling

The GEIS discusses on-site burial of cuttings generated during air drilling. This option is also viable for cuttings generated during drilling with fresh water as the drilling fluid. However, cuttings that are generated during drilling with polymer- or oil-based muds must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill. Operators should consult with the landfill operator and with the Division of Solid and Hazardous Materials on a site-specific basis regarding landfill options relative to measured NORM levels in the cuttings.

5.13.2 Reserve Pit Liner from Mud Drilling

The GEIS discusses on-site burial, with the landowner's permission, of the plastic liner used for the reserve pit for air-drilled wells. This option is also viable for wells where fresh-water is the drilling fluid. However, pit liners for reserve pits where polymer- or oil-based drilling muds are used must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill.

5.13.3 Flowback Water

As discussed in Section 5.12, options exist or are being developed for treatment, recycling and reuse of flowback water. Nevertheless, proper disposal is required for flowback water that is not reused. Factors which could result in a need for disposal instead of reuse include lack of reuse opportunity (i.e., no other wells being fractured within reasonable time frames or a reasonable distance), prohibitively high contaminant concentrations which render the water untreatable to usable quality, or unavailability or infeasibility of treatment options for other reasons.

Flowback water requiring disposal is considered industrial wastewater, like many other water use byproducts. The Department has an EPA-approved program for the control of wastewater discharges. Under New York State law, the program is called the State Pollutant Discharge Elimination System and is commonly referred to as SPDES. The program controls point source discharges to ground waters and surface waters. SPDES permits are issued to wastewater dischargers, including POTW's, and include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

Potential flowback water disposal options discussed in the GEIS include:

- injection wells, which are regulated under both the Department's SPDES program and the federal Underground Injection Control ("UIC") program,
- municipal sewage treatment facilities, and
- out-of-state industrial treatment plants.

Road spreading for dust control and deicing (by a Part 364 Transporter with local government approval) is also discussed in the GEIS as a general disposition method used in New York for well-related fluids (not an option for flowback water). Use of existing or new private in-state waste water treatment plants, and injection for enhanced resource recovery in oil fields have also been suggested. More information about each of these options is presented below.

5.13.3.1 Injection Wells

Discussed in Chapter 15 of the GEIS, injection wells for disposal of brine associated with oil and gas operations are classified as Class IID in EPA's UIC program and require federal permits. Under the Department's SPDES program, these wells have been categorized and regulated as industrial discharges. The primary objective of both programs is protection of underground sources of drinking water, and neither the EPA nor the DEC issues a permit without a demonstration that injected fluids will remain confined in the disposal zone and isolated from fresh water aquifers. As noted in the 1992 Findings Statement, the permitting process for brine disposal wells "require[s] an extensive surface and subsurface evaluation which is in effect a supplemental EIS addressing technical issues. An additional site-specific environmental assessment and SEQR determination are required."

UIC permit requirements will be included by reference in the SPDES permit, and the Department may propose additional monitoring requirements and/or discharge limits for inclusion in the SPDES permit. A well permit issued by the Division of Mineral Resources is also required to drill or convert a well deeper than 500 feet for brine disposal. This permit is not issued until the required UIC and SPDES permits have been approved. More information about the required analysis and mitigation measures considered during this review is provided in Chapter 7. Because of the 1992 Finding that brine disposal wells require site-specific SEQRA review, mitigation measures are discussed in Chapter 7 for informational purposes only and are not being proposed on a generic basis.

5.13.3.3 Municipal Sewage Treatment Facilities

Municipal sewage treatment facilities, known as Publicly Owned Treatment Works ("POTWs") are regulated by the Department's Division of Water ("DOW"). POTWs typically discharge treated wastewater to surface water bodies, and operate under SPDES permits which include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

In general, POTWs must have a DEC-approved pretreatment program for accepting any industrial waste. POTWs must also notify DEC of any new industrial waste they plan to receive at their facility. POTWs are required to perform certain analyses to ensure they can handle the waste without upsetting their system or causing a problem in the receiving water. Ultimately, DEC needs to approve such analysis and modify SPDES permits as needed to insure water quality standards in receiving waters are maintained at all times. More detailed discussion of the potential environmental impacts and how they are mitigated is presented in Chapters 6 and 7.

5.13.3.4 Out-of-State Treatment Plants

The only regulatory role DEC has over disposal of flowback water at out-of-state municipal or industrial treatment plants is that transport of these fluids, which are considered industrial waste, must be by a licensed Part 364 Transporter.

For informational purposes, Table 5.14 lists out-of-state plants that have been proposed for disposition of flowback water recovered in New York.

Table 5-14 - Out-of-state treatment plants proposed for disposition of NY flowback water

Treatment Facility	**Location**	**County**
Advanced Waste Services	New Castle, PA	Lawrence
Eureka Resources	Williamsport, PA	Lycoming
Lehigh County Authority Pretreatment Plant	Fogelsville, PA	Lehigh
Liquid Assets Disposal	Wheeling, WV	Ohio
Municipal Authority of the City of McKeesport	McKeesport, PA	Allegheny
PA Brine Treatment, Inc.	Franklin, PA	Venango
Sunbury Generation	Shamokin Dam, PA	Snyder
Tri-County Waste Water Management	Waynesburg, PA	Greene
Tunnelton Liquids Co.	Saltsburg, PA	Indiana
Valley Joint Sewer Authority	Athens, PA	Bradford
Waste Treatment Corporation	Washington, PA	Washington

5.13.3.5 Road Spreading

Consistent with past practice regarding flowback water disposal, in January 2009, the DEC's Division of Solid and Hazardous Materials ("DSHM"), which is responsible for oversight of the Part 364 program, released a notification to haulers applying for, modifying, or renewing their Part 364 permit that flowback water may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to the Division of Mineral Resources. This notification is included as Appendix 12.

5.13.3.6 Private In-State Industrial Treatment Plants

Industrial facilities could be constructed or converted in New York to treat flowback water. Such facilities would require a SPDES permit for any discharge. Again, the SPDES permit for a dedicated treatment facility would include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

5.13.3.7 Enhanced Oil Recovery

Waterflooding is an enhanced oil recovery technique whereby water is injected into partially depleted oil reservoirs to displace additional oil and increase recovery. Waterflood operations in New York are regulated under Part 557 of the Department's regulations and under the EPA's Underground Injection Control Program.

EPA reviews proposed waterflood injectate to determine the threat of endangerment to underground sources of drinking water. Operations that are authorized by rule are required to submit an analysis of the injectate anytime it changes, and operations under permit are required to modify their permits to inject water from a new source. At this time, no waterflood operations in New York have EPA approval to inject flowback water.

5.13.4 Solid Residuals from Flowback Water Treatment

URS Corporation reports that residuals disposal from the limited on-site treatment currently occurring generally consists of injection into disposal wells.[114] Other options would be dependent upon the nature and composition of the residuals and would require site-specific consultation with the Department's Division of Solid and Hazardous Materials. Transportation would require a Part 364 Waste Transporters' Permit.

5.14 Well Cleanup and Testing

Wells are typically tested after drilling and stimulation to determine their productivity, economic viability, and design criteria for a pipeline gathering system if one needs to be constructed. If no gathering line exists, well testing necessitates that produced gas be flared. However, operators have reported that for Marcellus Shale development in the northern tier of Pennsylvania, flaring is minimized by construction of the gathering system ahead of well completion. Flaring is necessary during the initial 12 to 24 hours of flowback operations while the well is producing a high ratio of flowback water to gas, but no flow testing that requires an extended period of flaring is conducted. Operators report that without a gathering line in place, initial cleanup or testing that could require flaring could last for 3 to 30 days.

5.15 Summary of Operations Prior to Production

Table 5.15 summarizes the primary operations that may take place at a multi-well pad prior to the production phase, and their typical durations. This tabulation assumes that a smaller rig is used to drill the vertical wellbore and a larger rig is used for the horizontal wellbore. Rig availability and other parameters outside the operators' control may affect the listed time frames. As explained in Section 5.2, no more than two rigs would operate on the well pad concurrently.

Note that the early production phase at a pad may overlap with the activities summarized in Table 5.15, as some wells may be placed into production prior to drilling and completion of all the wells on a pad. All pre-production operations for an entire pad must be concluded within three years or less, in accordance with ECL §23-0501. Estimated duration of each operation may be shorter or longer depending on site specific circumstances.

---

[114] URS, p. 5-3.

Table 5-15 - Primary Pre-Production Well Pad Operations

Operation	Materials and Equipment	Activities	Duration
Access Road and Well Pad Construction	Backhoes, bulldozers and other types of earth-moving equipment.	Clearing, grading, pit construction, placement of road materials such as geotextile and gravel.	Up to 4 weeks per well pad
Vertical Drilling with Smaller Rig	Drilling rig, fuel tank, pipe racks, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing surface casing, truck trips for delivery of equipment and cement. Delivery of equipment for horizontal drilling may commence during late stages of vertical drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Horizontal Drilling with Larger Rig		Transport, assembly and setup, or repositioning on site of large rig and ancillary equipment.	5 – 30 days per well[115]
Horizontal Drilling	Drilling rig, mud system (pumps, tanks, solids control, gas separator), fuel tank, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing production casing, truck trips for delivery of equipment and cement. Deliveries associated with hydraulic fracturing may commence during late stages of horizontal drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Hydraulic Fracturing		Rig down and removal or repositioning of drilling equipment. Truck trips for delivery of temporary tanks, water, sand, additives and other fracturing equipment. Deliveries may commence during late stages of horizontal drilling.	30 – 60 days per well, or per well pad if all wells treated during one mobilization
Hydraulic Fracturing Procedure	Temporary water tanks, generators, pumps, sand trucks, additive delivery trucks and containers (see Section 5.6.1), blending unit, personnel vehicles, associated outbuildings, including computerized monitoring equipment.	Fluid pumping, and use of wireline equipment between pumping stages to raise and lower tools used for downhole well preparation and measurements. Computerized monitoring. Continued water and additive delivery.	2 – 5 days per well, including approximately 40 to 100 hours of actual pumping
Fluid Return ("Flowback") and Treatment	Gas/water separator, flare stack, temporary water tanks, mobile water treatment units, trucks for fluid removal if necessary, personnel vehicles.	Rig down and removal or repositioning of fracturing equipment; controlled fluid flow into treating equipment, tanks, lined pits, impoundments or pipelines; truck trips to remove fluid if not stored on site or removed by pipeline.	2 – 8 weeks per well, may occur concurrently for several wells
Waste Disposal	Earth-moving equipment, pump trucks, waste transport trucks.	Pumping and excavation to empty/reclaim reserve pit(s). Truck trips to transfer waste to disposal facility.	Up to 6 weeks per well pad

[115] The shorter end of the time frame for drilling preparations applies if the rig is already at the well pad and only needs to be repositioned. The longer end applies if the rig must be brought from off-site and is proportional to the distance which the rig must be moved. This time frame will occur prior to vertical drilling if the same rig is used for the vertical and horizontal portions of the wellbore.

Operation	Materials and Equipment	Activities	Duration
		Truck trips to remove temporary water storage tanks.	
Well Cleanup and Testing	Well head, flare stack, brine tanks. Earth-moving equipment.	Well flaring and monitoring. Truck trips to empty brine tanks. Gathering line construction may commence if not done in advance.	½ - 30 days per well

5.16 Natural Gas Production

5.16.1 Partial Site Reclamation

Subsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production.

Well pad size during the production phase will be influenced on a site-specific basis by topography and generally by the space needed to support production activities and well servicing. According to operators, multi-well pads will range between one and three acres in size during the production phase, after partial reclamation.

5.16.2 Gas Composition

5.16.2.1 Hydrocarbons

As discussed in Chapter 4 and shown on the maps accompanying the discussion in that section, most of the Utica Shale and most of the Marcellus Shale "fairway" are in the dry gas window as defined by thermal maturity and vitrinite reflectance. In other words, the shales would not be expected to produce liquid hydrocarbons such as oil or condensate. This is corroborated by gas composition analyses provided by one operator for wells in the northern tier of Pennsylvania and shown in Table 5.16.

Table 5-16 - Marcellus Gas Composition from Bradford County, PA

Mole percent samples from Bradford Co., PA												
Sample Number	Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	i-Butane	n-Butane	i-Pentane	n-Pentane	Hexanes +	Oxygen	sum
1	0.297	0.063	96.977	2.546	0.107		0.01					100
2	0.6	0.001	96.884	2.399	0.097	0.004	0.008	0.003	0.004			100
3	0.405	0.085	96.943	2.449	0.106	0.003	0.009					100

Mole percent samples from Bradford Co., PA												
Sample Number	Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	i-Butane	n-Butane	i-Pentane	n-Pentane	Hexanes +	Oxygen	sum
4	0.368	0.046	96.942	2.522	0.111	0.002	0.009					100
5	0.356	0.067	96.959	2.496	0.108	0.004	0.01					100
6	1.5366	0.1536	97.6134	0.612	0.0469					0.0375		100
7	2.5178	0.218	96.8193	0.4097	0.0352							100
8	1.2533	0.1498	97.7513	0.7956	0.0195		0.0011			0.0294		100
9	0.2632	0.0299	98.0834	1.5883	0.0269	0.0000	0.0000	0.0000	0.0000	0.0000	0.0083	100
10	0.4996	0.0551	96.9444	2.3334	0.0780	0.0157	0.0167	0.0000	0.0000	0.0000	0.0571	100
11	0.1910	0.0597	97.4895	2.1574	0.0690	0.0208	0.0126	0.0000	0.0000	0.0000	0.0000	100
12	0.2278	0.0233	97.3201	2.3448	0.0731	0.0000	0.0032	0.0000	0.0000	0.0000	0.0077	100

ICF International, reviewing the above data under contract to NYSERDA, notes that samples 1, 3, 4 had no detectable hydrocarbons greater than n-butane. Sample 2 had no detectable hydrocarbons greater than n-pentane. Based on the low VOC content of these compositions, pollutants such as BTEX are not expected. [116] BTEX would normally be trapped in liquid phase with other components like natural gas liquids, oil or water. Fortuna Energy reports that it has sampled for benzene, toluene, and xylene and has not detected it in its gas samples or water analyses.

5.16.2.2 Hydrogen Sulfide

As further reported by ICF, sample number 1 in Table 5.16 included a sulfur analysis and found less than 0.032 grams sulfur per 100 cubic feet. The other samples did not include sulfur analysis. Chesapeake Energy reports that, to date, no hydrogen sulfide has been detected at any of its active interconnects in Pennsylvania. Fortuna Energy reports testing for hydrogen sulfide regularly with readings of 2 to 4 parts per million during a brief period on one occasion in its vertical Marcellus wells, and its presence has not reoccurred since.

5.16.3 Production Rate

Production rates are difficult to predict accurately for a play that has not yet been developed or is in the very early stages of development. One operator has indicated that its Marcellus production facility design will have a maximum capacity of either 6 MMcf per day or 10 MMcf per day,

[116] ICF Task 2, pp. 29-30.

whichever is appropriate. Another operator postulated long-term production for a single Marcellus well in New York as follows:

- Year 1 – Initial rate of 2.8 MMcf/d declining to 900 Mcf/d.
- Years 2 to 4 – 900 Mcf/d declining to 550 Mcf/d.
- Years 5 to 10 – 550 Mcf/d declining to 225 Mcf/d
- Year 11 and after – 225 Mcf/d declining at 3% per annum

5.16.4 Well Pad Production Equipment

In addition to the assembly of pressure-control devices and valves at the top of the well known as the "wellhead," "production tree" or "Christmas tree," equipment at the well pad during the production phase will likely include:

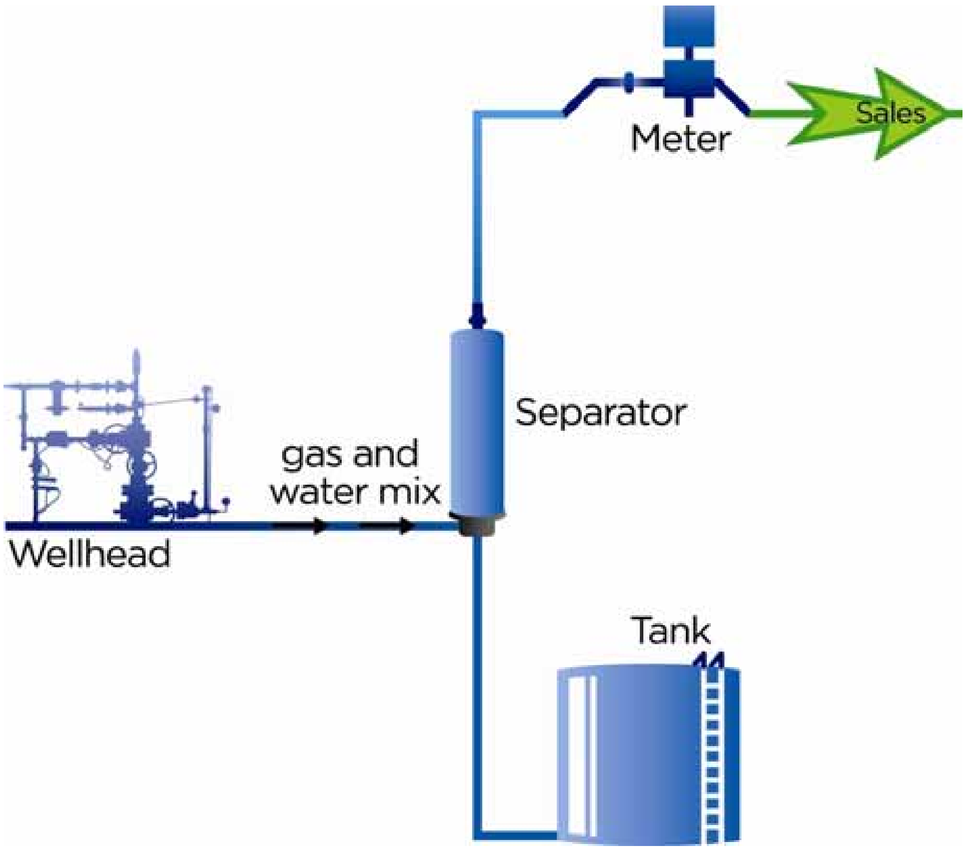
- A small inline heater that is in use for the first 6 to 8 months of production and during winter months to ensure freezing does not occur in the flow line due to Joule-Thompson effect (each well or shared),
- A two-phase gas/water separator,
- Gas metering devices (each well or shared),
- Water metering devices (each well or shared) and
- Brine storage tanks (shared by all wells).

In addition:

- A well head compressor may be added during later years after gas production has declined and
- A triethylene glycol (TEG) dehydrator may be located at some well sites, although typically the gas is sent to a gathering system for compression and dehydration at a compressor station.

Produced gas flows from the wellhead to the separator through a two- to three-inch diameter pipe ("flow line"). The operating pressure in the separator will typically be in the 100 to 200 psi range depending on the stage of the wells' life. At the separator, water will be removed from the gas stream via a dump valve and sent by pipe ("water line") to the brine storage tanks. The gas continues through a meter and to the departing gathering line, which carries the gas to a centralized compression facility. See Figure 5.6.

Figure 5-6 - Simplified Illustration of Gas Production Process



5.16.5 Brine Storage

Based on experience to date in the northern tier of Pennsylvania, one operator reports that brine production has typically been less than 10 barrels per day after the initial flowback operation and once the well is producing gas. Another operator reports that the rate of brine production during the production phase is about to 5 - 20 barrels per million cubic feet of gas produced.

One or more brine tanks will be installed on-site, along with truck loading facilities. At least one operator has indicated the possibility of constructing pipelines to move brine from the site, in which case truck loading facilities would not be necessary. Operators monitor brine levels in the tanks at least daily, with some sites monitored remotely by telemetric devices capable of sending alarms or shutting wells in if the storage limit is approached.

The storage of production brine in on-site pits has been prohibited in New York since 1984.

5.16.6 Brine Disposal

Production brine disposal options include injection wells, treatment plants and road spreading for dust control and deicing, which are all discussed in the GEIS. If produced water is trucked off-site, it must be hauled by approved Part 364 Waste Transporters.

With respect to road spreading, in January 2009 DEC's Division of Solid and Hazardous Materials ("DSHM"), responsible for oversight of the Part 364 Waste Transporter program, released a notification to haulers applying for, modifying, or renewing their Part 364 permits that any entity applying for a Part 364 permit or permit modification to use production fluid for road spreading must submit a petition for a beneficial use determination ("BUD") to the Department. The BUD and Part 364 permit must be issued by the Department prior to any production brine being removed from a well site for road spreading. See Appendix 12 for the notification.

5.16.7 Naturally Occurring Radioactive Materials in Marcellus Production Brine

Results of the Department's initial NORM analysis of Marcellus brine produced in New York are shown in Appendix 13. These samples were collected in late 2008 and 2009 from vertical gas wells in the Marcellus formation. The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options, including possible radioactive materials licensing. Potential impacts and proposed mitigation measures related to NORM are discussed in Chapters 6 and 7.

5.16.8 Gas Gathering and Compression

Operators report a 0.55 psi/foot to 0.60 psi/foot pressure gradient for the Marcellus Shale in the northern tier of Pennsylvania. Bottom-hole pressure equals the depth of the well times the pressure gradient. Therefore, the bottom-hole pressure on a 6,000-foot deep well will be between 3,300 and 3,600 psi. Wellhead pressures would be lower, depending on the makeup of the gas. One operator reported flowing tubing pressures in Bradford County, Pennsylvania, of 1,100 to 2,000 psi. Gas flowing at these pressures would not initially require compression to flow into a transmission line. Pressure decreases over time, however, and one operator stated an advantage of flowing the wells at as low a pressure as economically practical from the outset, to take advantage of the shale's gas desorption properties. In either case, the necessary compression to allow gas to flow into a large transmission line for sale would typically occur at a centralized site. Dehydration units, to remove water vapor from the gas before it flows into the sales line, would also be located at the centralized compression facilities.

Based on experience in the northern tier of Pennsylvania, operators estimate that a centralized facility will service well pads within a four to six mile radius. The gathering system from the well to a centralized compression facility consists of buried PVC or steel pipe, and the buried lines leaving the compression facility consists of coated steel.

Siting of gas gathering and pipeline systems, including the centralized compressor stations described above, is not subject to SEQRA review. See 6 NYCRR 617.5(c)(35). Therefore, the above description of these facilities, and the following description of the Public Service Commission's environmental review process, are presented for informational purposes only. This SGEIS will not result in SEQRA findings or new SEQRA procedures regarding the siting and approval of gas gathering and pipeline systems or centralized compression facilities.

Photo 5.28 shows an aerial view of a compression facility.

Photo 5.28 - Pipeline Compressor in New York. Source: Fortuna Energy

5.16.8.1 Regulation of Gas Gathering and Pipeline Systems

Article VII, “Siting of Major Utility Transmission Facilities,” is the section of the New York Public Service Law (PSL) that requires a full environmental impact review of the siting, design, construction, and operation of major intrastate electric and natural gas transmission facilities in New York State. The Public Service Commission (Commission or PSC) has approval authority over actions involving intrastate electric power transmission lines and high pressure natural fuel gas pipelines, and actions related to such projects. An example of an action related to a high pressure natural fuel gas pipeline is the siting and construction of an associated compressor station. While DEC and other agencies can have input into the review of an Article VII application or Notice of Intent (NOI) for an action, and can process ancillary permits for federally delegated programs, the ultimate decision on a given project application is made by the

Commission. The review and permitting process for natural fuel gas pipelines is separate and distinct from that used by the DEC to review and permit well drilling applications under ECL Article 23, and is traditionally conducted after a well is drilled, tested and found productive. For development and environmental reasons, along with anticipated success rates, it has been suggested that wells targeting the Marcellus shale and other low-permeability gas reservoirs using horizontal drilling and high-volume hydraulic fracturing may deserve consideration of pipeline certification by the PSC in advance of drilling to allow pipelines to be in place and operational at the time of the completion of the wells.

The PSC's statutory authority has its own "SEQR-like" review, record, and decision standards that apply to major gas and electric transmission lines. As mentioned above, PSC makes the final decision on Article VII applications. Article VII supersedes other State and local permits except for federally authorized permits; however, Article VII establishes the forum in which community residents can participate with members of State and local agencies in the review process to ensure that the application comports with the substance of State and local laws. Throughout the Article VII review process, applicants are strongly encouraged to follow a public information process designed to involve the public in a project's review. Article VII includes major utility transmission facilities involving both electricity and fuel gas (natural gas), but the following discussion, which is largely derived from PSC's guide entitled "The Certification Review Process for Major Electric and Fuel Gas Transmission Facilities," [117] is focused on the latter. While the focus of PSC's guide with respect to natural gas is the regulation and permitting of transmission lines at least ten miles long and operated at a pressure of 125 psig or greater, the certification process explained in the guide and outlined below provides the basis for the permitting of transmission lines less than ten miles long that will typically serve Marcellus Shale and other low-permeability gas reservoir wells.

Public Service Commission

PSC is the five member decision-making body established by PSL § 4 that regulates investor-owned electric, natural gas, steam, telecommunications, and water utilities in New York State.

---

[117] http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf

The Commission, made up of a Chairman and four Commissioners, decides any application filed under Article VII. The Chairman of the Commission, designated by the Governor, is also the chief executive officer of the Department of Public Service (DPS). Employees of the DPS serve as staff to the PSC.

DPS is the State agency that serves to carry out the PSC's legal mandates. One of DPS's responsibilities is to participate in all Article VII proceedings to represent the public interest. DPS employs a wide range of experts, including planners, landscape architects, foresters, aquatic and terrestrial ecologists, engineers, and economists, who analyze environmental, engineering, and safety issues, as well as the public need for a facility proposed under Article VII. These professionals take a broad, objective view of any proposal, and consider the project's effects on local residents, as well as the needs of the general public of New York State. Public participation specialists monitor public involvement in Article VII cases and are available for consultation with both applicants and stakeholders.

Article VII

The New York State Legislature enacted Article VII of the PSL in 1970 to establish a single forum for reviewing the public need for, and environmental impact of, certain major electric and gas transmission facilities. The PSL requires that an applicant must apply for a Certificate of Environmental Compatibility and Public Need (Certificate) and meet the Article VII requirements before constructing any such intrastate facility. Article VII sets forth a review process for the consideration of any application to construct and operate a major utility transmission facility. Natural fuel gas transmission lines originating at wells are commonly referred to as "gathering lines" because the lines may collect or gather gas from a single or number of wells which feed a centralized compression facility or other transmission line. The drilling of multiple Marcellus Shale or other low-permeability gas reservoir wells from a single well pad and subsequent production of the wells into one large diameter gathering line eliminates the need for construction and associated cumulative impacts from individual gathering lines if traditionally drilled as one well per location. The PSL defines major natural gas transmission facilities, which statutorily includes many gathering lines, as pipelines extending a distance of at least 1,000 feet and operated at a pressure of 125 psig or more, except where such natural gas pipelines:

- are located wholly underground in a city, or
- are located wholly within the right-of-way of a State, county or town highway or village street, or
- replace an existing transmission facility, and are less than one mile long.

Under 6 NYCRR § 617.5(c)(35), actions requiring a Certificate of Environmental Compatibility and Public Need under article VII of the PSL and the consideration of, granting or denial of any such Certificate are classified as "Type II" actions for the purpose of SEQR. Type II actions are those actions, or classes of actions, which have been found categorically to not have significant adverse impacts on the environment, or actions that have been statutorily exempted from SEQR review. Type II actions do not require preparation of an EAF, a negative or positive declaration, or an environmental impact statement (EIS) under SEQR. Despite the legal exemption from processing under SEQR, as previously noted, Article VII contains its own process to evaluate environmental and public safety issues and potential impacts, and impose mitigation measures as appropriate.

As explained in the GEIS, and shown in Table 5.17, PSC has siting jurisdiction over all lines operating at a pressure of 125 psig or more and at least 1,000 feet in length, and siting jurisdiction of lines below these thresholds if such lines are part of a larger project under PSC's purview. In addition, PSC's safety jurisdiction covers all natural gas gathering lines and pipelines regardless of operating pressure and line length. PSC's authority, at the well site, physically begins at the well's separator outlet. DEC's permitting authority over gathering lines operating at pressures less than 125 psig primarily focuses on the permitting of disturbances in environmentally sensitive areas, such as streams and wetlands, and the DEC is responsible for administering federally delegated permitting programs involving air and water resources. For all other pipelines regulated by the PSC, the DEC's jurisdiction is limited to the permitting of certain federally delegated programs involving air and water resources. Nevertheless, in all instances, the DEC either directly imposes mitigation measures through its permits or provides comments to the PSC which, in turn, routinely requires mitigation measures to protect environmentally sensitive areas.

Pre-Application Process

Early in the planning phase of a project, the prospective Article VII applicant is encouraged to consult informally with stakeholders. Before an application is filed, stakeholders may obtain information about a specific project by contacting the applicant directly and asking the applicant to put their names and addresses on the applicant's mailing list to receive notices of public information meetings, along with project updates. After an application is filed, stakeholders may request their names and addresses be included on a project "service list" which is maintained by the PSC. Sending a written request to the Secretary to the PSC to be placed on the service list for a case will allow stakeholders to receive copies of orders, notices and rulings in the case. Such requests should reference the Article VII case number assigned to the application.

Table 5-17 - Intrastate Pipeline Regulation[118]

PIPELINE TYPE	DEC	PSC
Gathering <125 psig	Siting jurisdiction only in environmentally sensitive areas where DEC permits, other than the well permit, are required. Permitting authority for federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**.
Gathering ≥125 psig, <1,000 ft.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**. Siting jurisdiction also applies if part of larger system subject to siting review. Public Service Law § 66, 16 NYCRR Subpart 85-1.4.
Fuel Gas Transmission* ≥125 psig, ≤1,000 ft., <5 mi., ≤6 in. diameter	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.

118 Adapted from the 1992 GEIS.

PIPELINE TYPE	DEC	PSC
Fuel Gas Transmission* ≥125 psig, ≥5 mi., <10 mi. Note: The pipelines associated with wells being considered in this document typically fall into this category, or possibly the one above.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.
Fuel Gas Transmission* ≥125 psig, ≥10 mi.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Article VII § 120, 16 NYCRR § 255.9, 16 NYCRR Subpart 85-2. Environmental assessment must be filed. Service of application to other agencies required.
* Federal Minimum Pipeline Safety Standards 49 CFR Part 192 supersedes PSC if line is closer than 150 ft. to a residence or in an urban area. ** Appendix 7-G(a) is required in all active farm lands. *** EM&CS&P means Environmental Management and Construction Standards and Practices.		

Application

An Article VII application must contain the following information:

- location of the line and right-of-way,
- description of the transmission facility being proposed,
- summary of any studies made of the environmental impact of the facility, and a description of such studies,
- statement explaining the need for the facility,
- description of any reasonable alternate route(s), including a description of the merits and detriments of each route submitted, and the reasons why the primary proposed route is best suited for the facility; and,
- such information as the applicant may consider relevant or the Commission may require.

In an application, the applicant is also encouraged to detail its public involvement activities and its plans to encourage public participation. DPS staff takes about 30 days after an application is filed to determine if the application is in compliance with Article VII filing requirements. If an application lacks required information, the applicant is informed of the deficiencies. The applicant can then file supplemental information. If the applicant chooses to file the supplemental information, the application is again reviewed by the DPS for a compliance determination. Once an application for a Certificate is filed with the PSC, no local municipality or other State agency may require any hearings or permits concerning the proposed facility.

Timing of Application & Pipeline Construction

The extraction of projected economically recoverable reserves from the Marcellus Shale, and other low-permeability gas reservoirs, presents a unique challenge and opportunity with respect to the timing of an application and ultimate construction of the pipeline facilities necessary to tie this gas source into the transportation system and bring the produced gas to market. In the course of developing other gas formations, the typical sequence of events begins with the operator first drilling a well to determine its productivity and, if successful, then submitting an Article VII application for PSC approval to construct the associated pipeline. This reflects the risk associated with conventional oil and gas exploration where finding natural gas in paying quantities is not guaranteed.

The typical procedure of drilling wells, testing wells by flaring and then constructing gathering lines may not be ideally suited for the development of the Marcellus Shale and other low permeability reservoirs. To date, the success rate of horizontally drilled and hydraulically fractured Marcellus Shale wells in neighboring Pennsylvania and West Virginia, as reported by three companies, is one hundred percent for 44 wells drilled.[119] This rate of success is apparently due primarily to the fact that the Marcellus Shale reservoir appears to contain natural gas in sufficient quantities which can be produced using horizontal drilling and high-volume hydraulic fracturing technology. All gathering lines constructed prior to Marcellus Shale well drilling in the above referenced states have been put into operation and are serving their intended purpose. It is highly unlikely that an operator in New York would make a substantial investment in a pipeline ahead of completing a well unless there is an extremely high probability of finding gas in suitable quantities and at viable flowrates.

In addition, the Marcellus Shale formation has a high concentration of clay that is sensitive to fresh water contact which makes the formation susceptible to re-closing if the flowback fluid and natural gas do not flow immediately after hydraulic fracturing operations. The horizontal drilling and hydraulic fracturing technique used to tap into the Marcellus requires that the well be flowed back and gas produced immediately after the well has been fractured and completed, otherwise the formation may be damaged and the well may cease to be economically productive. In

[119] Chesapeake Energy Corp., Fortuna Energy Inc., Seneca Resources Corp.

addition to enhancing the completion by preventing formation damage, having a pipeline in place when a well is initially flowed would reduce the amount of gas flared to the atmosphere during initial recovery operations. This type of completion with limited or no flaring is sometimes referred to as a "green" or reduced emissions completion (REC). To combat formation damage during hydraulic fracturing with conventional fluids, a new and alternative hydraulic fracturing technology recently entered the Canadian market and was also used in Pennsylvania in September 2009. It uses liquefied petroleum gas (LPG), consisting mostly of propane in place of water-based hydraulic fracturing fluids. Using propane not only minimizes formation damage, but also eliminates the need to source water for hydraulic fracturing, recover flowback fluids to the surface and dispose of the flowback fluids.[120] While it's unknown if and when LPG hydraulic fracturing will be proposed in New York, having gathering infrastructure in place, would allow the propane to be recovered during flowback directly to a pipeline along with the produced natural gas.

Also, if installed prior to well drilling, an in-place gas production pipeline could serve a second purpose and be used initially to transport fresh water or recycled hydraulic fracturing fluids to the well site for use in hydraulic fracturing the first well on the pad, or for transport of fluids to a centralized impoundment. This in itself would reduce or eliminate other fluid transportation options, such as trucking and construction of a separate fluid pipeline, and associated impacts. Because of the many potential benefits noted above, which have been demonstrated in other states, it has been suggested that New York should have the option to certify and build pipelines in advance of well drilling targeting the Marcellus Shale and other low-permeability gas reservoirs.

Filing and Notice Requirements

Article VII requires that a copy of an application for a transmission line ten miles or longer in length be provided by the applicant to the DEC, the Department of Economic Development, the Secretary of State, the Department of Agriculture and Markets and the Office of Parks, Recreation and Historic Preservation, and each municipality in which any portion of the facility

[120] Smith, 2008. *FRACforward, Startup Cracks Propane Fracture Puzzle, Provides 'Green' Solution*, Nickle's New Technology Magazine, www.ntm.nickles.com

is proposed to be located. This is done for both the primary route proposed and any alternative locations listed. A copy of the application must also be provided to the State legislators whose districts the proposed primary facility or any alternative locations listed would pass through. Service requirements for transmission lines less than 10 miles in length are slightly different but nevertheless comprehensive.

An Article VII application for a transmission line ten miles or longer in length must be accompanied by proof that notice was published in a newspaper(s) of general circulation in all areas through which the facility is proposed to pass, for both its primary and alternate routes. The notice must contain a brief description of the proposed facility and its proposed location, along with a discussion of reasonable alternative locations. An applicant is not required to provide copies of the application or notice of the filing of the application to individual property owners of land on which a portion of either the primary or alternative route is proposed. However, to help foster public involvement, an applicant is encouraged to do so.

Party Status in the Certification Proceeding

Article VII specifies that the applicant and certain State and municipal agencies are parties in any case. The DEC and the Department of Agriculture & Markets are among the statutorily named parties and usually actively participate. Any municipality through which a portion of the proposed facility will pass, or any resident of such municipality, may also become a formal party to the proceeding. Obtaining party status enables a person or group to submit testimony, cross-examine witnesses of other parties and file briefs in the case. Being a party also entails the responsibility to send copies of all materials filed in the case to all other parties. DPS staff participates in all Article VII cases as a party, in the same way as any other person who takes an active part in the proceedings.

The Certification Process

Once all of the information needed to complete an application is submitted and the application is determined to be in compliance, review of the application begins. In a case where a hearing is held, the Commission’s Office of Hearings and Alternative Dispute Resolution provides an Administrative Law Judge (ALJ) to preside in the case. The ALJ is independent of DPS staff and other parties and conducts public statement and evidentiary hearings and rules on procedural matters. Hearings help the Commission decide whether the construction and operation of new transmission facilities will fulfill the public need, be compatible with environmental values and the public health and safety, and comply with legal requirements. After considering all the evidence presented in a case, the ALJ usually makes a recommendation for the Commission's consideration.

Commission Decision

The Commission reviews the ALJ's recommendation, if there is one, and considers the views of the applicant, DPS staff, other governmental agencies, organizations, and the general public, received in writing, orally at hearings or at any time in the case. To grant a Certificate, either as proposed or modified, the Commission must determine all of the following:

1. the need for the facility,
2. the nature of the probable environmental impact,
3. the extent to which the facility minimizes adverse environmental impact, given environmental and other pertinent considerations,
4. that the facility location will not pose undue hazard to persons or property along the line,
5. that the location conforms with applicable State and local laws; and,
6. the construction and operation of the facility is in the public interest.

Following Article VII certification, the Commission typically requires the certificate holder to submit various additional documents to verify its compliance with the certification order. One of the more notable compliance documents, an Environmental Management and Construction Plan (EM&CP), must be approved by the Commission before construction can begin. The EM&CP details the precise field location of the facilities and the special precautions that will be taken during construction to ensure environmental compatibility. The EM&CP must also indicate the practices to be followed to ensure that the facility is constructed in compliance with applicable safety codes and the measures to be employed in maintaining and operating the facility once it is constructed. Once the Commission is satisfied that the detailed plans are consistent with its decision and are appropriate to the circumstances, it will authorize commencement of construction. DPS staff is then responsible for checking the applicant's practices in the field.

Amended Certification Process

In 1981, the Legislature amended Article VII to streamline procedures and application requirements for the certification of fuel gas transmission facilities operating at 125 psig or more, and that extend at least 1,000 feet, but less than ten miles. The pipelines or gathering lines associated with wells being considered in this document typically fall into this category, and, consequently, a relatively expedited certification process occurs that is intended to be no less protective. The updated requirements mimic those described above with notable differences being: 1) a NOI may be filed instead of an application, 2) there is no mandatory hearing with testimony or required notice in newspaper, and 3) the PSC is required to act within thirty or sixty days depending upon the size and length of the pipeline.

The updated requirements applicable to such fuel gas transmission facilities are set forth in PSL Section 121-a and 16 NYCRR Sub-part 85-1. All proposed pipeline locations are verified and walked in the field by DPS staff as part of the review process, and staff from the DEC and Department of Agriculture & Markets may participate in field visits as necessary. As mentioned above, these departments normally become active parties in the NOI or application review process and usually provide comments to DPS staff for consideration. Typical comments from DEC and Agriculture and Markets relate to the protection of agricultural lands, streams, wetlands, rare or state-listed animals and plants, and significant natural communities and habitats.

Instead of an applicant preparing its own environmental management and construction standards and practices (EM&CS&P), it may choose to rely on a PSC approved set of standards and practices, the most comprehensive of which was prepared by DPS staff in February 2006.[121] The DPS authored EM&CS&P was written primarily to address construction of smaller-scale fuel gas transmission projects envisioned by PSL Section 121-a that will be used to transport gas from the wells being considered in this document. Comprehensive planning and construction management are key to minimizing adverse environmental impacts of pipelines and their construction. The EM&CS&P is a tool for minimizing such impacts of fuel gas transmission

[121] DPS, 2006. *Environmental Management and Construction Standards and Practices for Underground Transmission and Distribution Facilities in New York State*, Office of Electricity & Environment, Albany, NY.

pipelines reviewed under the PSL. The standards and practices contained in the 2006 EM&CS&P handbook are intended to cover the range of construction conditions typically encountered in constructing pipelines in New York.

The pre-approved nature of the 2006 EM&CS&P supports a more efficient submittal and review process, and aids with the processing of an application or NOI within mandated time frames. The measures from the EM&CS&P that will be used in a particular project must be identified on a checklist and included in the NOI or application. A sample checklist is included as Appendix 14, which details the extensive list of standards and practices considered in DPS's EM&CS&P and readily available to the applicant. Additionally, the applicant must indicate and include any measures or techniques it intends to modify or substitute for those included in the PSC approved EM&CS&P.

An important measure specified in the EM&CS&P checklist is a requirement for supervision and inspection during various phases of the project. Page four of the 2006 EM&CS&P states "At least one Environmental Inspector (EI) is required for each construction spread during construction and restoration. The number and experience of EIs should be appropriate for the length of the construction spread and number/significance or resources affected." The 2006 EM&CS&P also requires that the name(s) of qualified Environmental Inspector(s) and a statement(s) of the individual's relative project experience be provided to the DPS prior to the start of construction for DPS staff's review and acceptance. Another important aspect of the PSC approved EM&CS&P is that Environmental Inspectors have stop-work authority entitling the EI to stop activities that violate Certificate conditions or other federal, State, local or landowner requirements, and to order appropriate corrective action.

Conclusion

Whether an applicant submits an Article VII application or Notice of Intent as allowed by the Public Service Law, the end result is that all Public Service Commission issued Certificates of Environmental Compatibility and Public Need for fuel gas transmission lines contain ordering clauses, stipulations and other conditions that the Certificate holder must comply with as a condition of acceptance of the Certificate. Many of the Certificate's terms and conditions relate to environmental protection. The Certificate holder is fully expected to comply with all of the terms and conditions or it may face an enforcement action. Department of Public Service staff monitor construction activities to help ensure compliance with the Commission's orders. After installation and pressure testing of a pipeline, its operation, monitoring, maintenance and eventual abandonment must also be conducted in accordance with and adhere to the provisions of the Certificate and New York State law and regulations.

5.17 Well Plugging

As described in the GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continued protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well.

When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.

Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site.

Removal of all surface equipment and full site restoration are required after the well is plugged. Proper disposal of surface equipment includes testing for NORM to determine the appropriate disposal site.

The plugging requirements summarized above are described in detail in Chapter 11 of the GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review.

5.18 Other States' Regulations

The Department committed in Section 2.1.2 of the Final Scope for this SGEIS to evaluate the effectiveness of other states' regulations with respect to hydraulic fracturing and to consider the advisability of adopting additional protective measures based on those that have proven successful in other states for similar activities. Department staff consulted the following sources to conduct this evaluation:

1) *Ground Water Protection Council, 2009b.* The Ground Water Protection Council (GWPC) is an association of ground water and underground injection control regulators. In May 2009, GWPC reported on its review of the regulations of 27 oil and gas producing states. The stated purpose of the review was to evaluate how the regulations relate to direct protection of water resources.

2) *ICF International, 2009a.* NYSERDA contracted ICF International to conduct a regulatory analysis of New York and up to four other shale gas states regarding notification, application, review and approval of hydraulic fracturing and re-fracturing operations. ICF's review included Arkansas (Fayetteville Shale), Louisiana (Haynesville Shale), Pennsylvania (Marcellus Shale) and Texas (Barnett Shale).

3) *Alpha Environmental Consultants, Inc., 2009.* NYSERDA contracted Alpha Environmental Consultants, Inc., to survey policies, procedures, regulations and recent regulatory changes related to hydraulic fracturing in Pennsylvania, Colorado, New Mexico, Wyoming, Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas. Based on its review, Alpha summarized potential permit application requirements to evaluate well pad impacts and also provided recommendations for minimizing the likelihood and impact of liquid chemical spills that are reflected elsewhere in this SGEIS.

4) *Colorado Oil & Gas Conservation Commission, Final Amended Rules.* In the spring of 2009, the Colorado Oil & Gas Conservation Commission adopted new regulations regarding, among other things, the chemicals that are used at wellsites and public water supply protection. Colorado's program was included in Alpha's regulatory survey, but the amended rules' emphasis on topics pertinent to this SGEIS led staff to do a separate review of the regulations related to chemical use and public water supply buffer zones.

5) *June 2009 Statements on Hydraulic Fracturing from State Regulatory Officials.* On June 4, 2009, GWPC's president testified before Congress (i.e., the House Committee on Natural

Resources' Subcommittee on Energy and Mineral Resources) regarding hydraulic fracturing. Attached to his written testimony were letters from regulatory officials in Ohio, Pennsylvania, New Mexico, Alabama and Texas. These officials unanimously stated that no instances of ground water contamination attributable to hydraulic fracturing had been documented in their states. Also in June 2009, the Interstate Oil and Gas Compact Commission compiled and posted on its website statements from oil and gas regulators in 12 of its member states: Alabama, Alaska, Colorado, Indiana, Kentucky, Louisiana, Michigan, Oklahoma, Tennessee, Texas, South Dakota and Wyoming.[122] These officials also unanimously stated that no verified instances of harm to drinking water attributable to hydraulic fracturing had occurred in their states despite use of the process in thousands of wells over several decades. All 15 statements are included in Appendix 15.

Emphasis on proper well casing and cementing procedures is identified by GWPC and state regulators as the primary safeguard against ground water contamination during the hydraulic fracturing procedure. This approach has been effective, based on the regulatory statements summarized above and included in the Appendices. Improvements to casing and cementing requirements, along with enhanced requirements regarding other activities such as pit construction and maintenance, are appropriate responses to problems and concerns that arise as technologies advance. Chapters 7 and 8 of this SGEIS, on mitigation measures and the permit process, reflect consideration of any of those requirements regarding either hydraulic fracturing or ancillary activities in other states that (1) are more stringent than New York's and (2) address potential impacts associated with horizontal drilling and high-volume hydraulic fracturing that are not covered by the 1992 GEIS.

Additional information is provided below regarding the findings and conclusions expressed by GWPC, ICF and Alpha that are most relevant to the mitigation approach presented in this SGEIS. Pertinent sections of Colorado's final amended rules are also summarized.

5.18.1 Summary of GWPC's Review

GWPC's overall conclusion, based on its review of 27 states' regulations, including New York's, is that state oil and gas regulations are adequately designed to directly protect water resources. Hydraulic fracturing is one of eight topics reviewed. The other seven topics were permitting, well construction, temporary abandonment, well plugging, tanks, pits and waste handling/spills.

---

[122] http://www.iogcc.state.ok.us/hydraulic-fracturing

5.18.1.1 GWPC - Hydraulic Fracturing

With respect to the specific topic of hydraulic fracturing, GWPC found that states generally focus on well construction (i.e., casing and cement) and noted the importance of proper handling and disposal of materials. GWPC recommends identification of fracturing fluid additives and concentrations, as well as a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. GWPC did not provide thresholds for defining when hydraulic fracturing should be considered "shallow" or "in close proximity" to underground sources of drinking water. GWPC did not recommend additional controls on the actual conduct of the hydraulic fracturing procedure itself for deep non-coalbed methane wells that are not in close proximity to drinking water sources, nor did GWPC suggest any restrictions on fracture fluid composition for such wells.

GPWC urges caution against developing and implementing regulations based on anecdotal evidence alone, but does recommend continued investigation of complaints of ground water contamination to determine if a causal relationship to hydraulic fracturing can be established.

5.18.1.2 GWPC – Other Activities

Of the other seven topic areas reviewed by GWPC, permitting, well construction, tanks, pits and waste handling and spills are addressed by this SGEIS. GWPC's recommendations regarding each of these are summarized below.

Permitting

Unlike New York, in many states the oil and gas regulatory authority is a separate agency from other state-level environmental programs. GWPC recommends closer, more formalized cooperation in such instances. Another suggested action related to permitting is that states continue to expand use of electronic data management to track compliance, facilitate field inspections and otherwise acquire, store, share, extract and use environmental data.

Well Construction

GWPC recommends adequate surface casing and cement to protect ground water resources, adequate cement on production casing to prevent upward migration of fluids during all reservoir conditions, use of centralizers and the opportunity for state regulators to witness casing and cementing operations.

Tanks

Tanks, according to GWPC, should be constructed of materials suitable for their usage. Containment dikes should meet a permeability standard and the areas within containment dikes should be kept free of fluids except for a specified length of time after a tank release or a rainfall event.

Pits

GWPC's recommendations target "long-term storage pits." Permeability and construction standards for pit liners are recommended to prevent downward migration of fluids into ground water. Excavation should not be below the seasonal high water table. GPWC recommends against use of long-term storage pits where underlying bedrock contains seepage routes, solution features or springs. Construction requirements to prevent ingress and egress of fluids during a flood should be implemented within designated 100-year flood boundaries. Pit closure specifications should address disposition of fluids, solids and the pit liner. Finally, GWPC suggests prohibiting the use of long-term storage pits within the boundaries of public water supply and wellhead protection areas.

Waste Handling and Spills

In the area of waste handling, GWPC's suggests actions focused on surface discharge because "approximately 98% of all material generated . . . is produced water,"[123] and injection via disposal wells is highly regulated. Surface discharge should not occur without the issuance of an appropriate permit or authorization based on whether the discharge could enter water. As reflected in Colorado's recently amended rules, soil remediation in response to spills should be in accordance with a specific cleanup standard such as a Sodium Absorption Ratio (SAR) for salt-affected soil.

[123] GWPC, 2009b. p. 30

5.18.2 ICF Findings

ICF concluded that regulatory procedures in all of the states reviewed, including New York, are sufficient to prevent fracturing fluid from flowing upward along the wellbore and contacting water-bearing strata adjacent to the borehole. ICF also concluded that, under specific conditions, "currently proposed approaches to hydraulic fracturing will not have reasonably foreseeable adverse environmental impacts on potential freshwater aquifers due to subsurface migration of fracturing fluids."[124] The conditions under which ICF's analysis supports this conclusion are:

- Maximum depth to the bottom of a potential aquifer ≤ 1,000 feet
- Minimum depth of the target fracture zone ≥ 2,000 feet
- Average hydraulic conductivity of intervening strata ≤ $1E^{-5}$ cm/sec
- Average porosity of intervening strata ≥ 10%

ICF states that "even under the combination of these conditions most favorable to flow, the pressures and volumes proposed for hydraulic fracturing are insufficient to cause migration of fluids from the fracture zone to the overlying aquifer in the short time that fracturing pressures would be applied. Conditions outside of these limits may require site-specific review."[125]

5.18.3 Summary of Alpha's Regulatory Survey

Topics reviewed by Alpha include: pit rules and specifications, reclamation and waste disposal, water well testing, fracturing fluid reporting requirements, hydraulic fracturing operations, fluid use and recycling, materials handling and transport, minimization of potential noise and lighting impacts, setbacks, multi-well pad reclamation practices, naturally occurring radioactive materials and stormwater runoff. Alpha supplemented its regulatory survey with discussion of practices directly observed during field visits to active Marcellus sites in the northern tier of Pennsylvania (Bradford County).

---

[124] Ibid., p. 36

[125] ICF, 2009a

5.18.3.1 Alpha – Hydraulic Fracturing

Alpha's review with respect to the specific hydraulic fracturing procedure focused on regulatory processes, i.e., notification, approval and reporting. Among the states Alpha surveyed, Wyoming appears to require the most information.

Pre-Fracturing Notification and Approval

Of the nine states Alpha surveyed, West Virginia, Wyoming, Colorado and Louisiana require notification or approval prior to conducting hydraulic fracturing operations. Pre-approval for hydraulic fracturing is required in Wyoming, and the operator must provide information in advance regarding the depth to perforations or the open hole interval, the water source, the proppants and estimated pump pressure. Consistent with GWPC's recommendation, information required by Wyoming Oil and Gas Commission Rules also includes the trade name of fluids.

Post-Fracturing Reports

Wyoming requires that the operator notify the state regulatory agency of the specific details of a completed fracturing job. Wyoming requires a report of any fracturing and any associated activities such as shooting the casing, acidizing and gun perforating. The report is required to contain a detailed account of the work done; the manner undertaken; the daily volume of oil or gas and water produced, prior to, and after the action; the size and depth of perforation; the quantity of sand, chemicals and other material utilized in the activity and any other pertinent information.

5.18.3.2 Alpha – Other Activities

The Department's development of the overall mitigation approach proposed in this SGEIS also considered Alpha's discussion of other topics included in the regulatory survey. Key points are summarized below.

Pit Rules and Specifications

Alpha's review focused on reserve pits at the well pad. Several states have some general specifications in common. These include:

- Freeboard monitoring and maintenance of minimum freeboard,

- Minimum vertical separation between the seasonal high ground water table and the pit bottom, commonly 20 inches,

- Minimum liner thickness of 20 – 30 mil, and maximum liner permeability of 1 x 10^{-7} cm/sec,

- Compatibility of liner material with the chemistry of the contained fluid, placement of the liner with sufficient slack to accommodate stretching, installation and seaming in accordance with the manufacturer's specifications,

- Construction to prevent surface water from entering the pit,

- Sidewalls and bottoms free of objects capable of puncturing and ripping the liner, and

- Pit sidewall slopes from 2:1 to 3:1.

Alpha recommends that engineering judgment be applied on a case-by-case basis to determine the extent of vertical separation that should be required between the pit bottom and the seasonal high water table. Consideration should be given to the nature of the unconsolidated material and the water table; concern may be greater, for example, in a lowland area with high rates of inflow from medium- to high-permeability soils than in upland till-covered areas.

Reclamation and Waste Disposal

In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York."[126] The best management practices referenced by Alpha include:

- Use of steel tanks to contain flowback water at the well pad,

- On-site or offsite flowback water treatment for re-use, with residual solids disposed or further treated for beneficial use or disposal in accordance with Pennsylvania's regulations,

- Offsite treatment and disposal of produced brine,

- On-site encapsulation and burial of drill cuttings if they do not contain constituents at levels that exceed Pennsylvania's environmental standards,

[126] Alpha, 2009. p. 2-15.

- Containerization of sewage and putrescible waste and transport off-site to a regulated sewage treatment plant or landfill,

- Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination, and

- Partial reclamation of well pad areas not necessary to support gas production.

Alpha noted that perforating or ripping the pit liner prior to on-site burial could prevent the formation of an impermeable barrier or the formation of a localized area of poor soil drainage. Addition of fill may be advisable to mitigate subsidence as drill cuttings dewater and consolidate.[127]

Water Well Testing

Of the jurisdictions surveyed, Colorado and the City of Fort Worth have water well testing requirements specifically directed at unconventional gas development within targeted regions. Colorado's requirements are specific to two particular situations: drilling through the Laramie Fox Hills Aquifer and drilling coal-bed methane wells. Fort Worth's regulations pertain to Barnett shale development, where horizontal drilling and high-volume hydraulic fracturing are performed, and address all fresh water wells within 500 feet of the surface location of the gas well. Ohio requires sampling of wells within 300 feet prior to drilling within urbanized areas. West Virginia also has testing requirements for wells and springs within 1,000 feet of the proposed oil or gas well. Louisiana, while it does not require testing, mandates that the results of voluntary sampling be provided to the landowner and the regulatory agency.

Pennsylvania regulations presume the operator to be the cause of adverse water quality impacts unless demonstrated otherwise by pre-drilling baseline testing, assuming permission was given by the landowner. Alpha suggests that the following guidance provided by Pennsylvania and voluntarily implemented by operators in the northern tier of Pennsylvania and southern tier of New York should be effective:

[127] Alpha, 2009. p. 2-15

- With the landowner's permission, monitor the quality of any water supply within 1,000 feet of a proposed drilling operation (at least one operator expands the radius to 2,000 feet if there are no wells within 1,000 feet);
- Analyze the water samples using an independent, state certified, water testing laboratory; and
- Analyze the water for sodium, chlorides, iron, manganese, barium and arsenic. (Alpha recommends analysis for methane types, total dissolved solids, chlorides and pH.)

Fluid Use and Recycling

Regarding surface water withdrawals, Alpha found that the most stringent rules in the states surveyed are those implemented in Pennsylvania by the Delaware and Susquehanna River Basin Commissions.

None of the states surveyed have any requirements, rules or guidance relating to the use of treated municipal waste water.

Ohio allows the re-use of drilling and flowback water for dust and ice control with an approval resolution, and will consider other options depending on technology. West Virginia recommends that operators consider recycling flowback water.

Practices observed in the northern tier of Pennsylvania include treatment at the well pad to reduce TDS levels below 30,000 ppm. The treated fluids are diluted by mixing with fresh makeup water and used for the next fracturing project.

Materials Handling and Transport

Alpha provided the review of pertinent federal and state transportation and container requirements that is included in Section 5.5, and concluded that motor transport of all hazardous fracturing additives or mixtures to drill sites is adequately covered by existing federal and NYSDOT regulations.[128] Best management practices such as the following were identified by Alpha for implementation on the well pad:

- Monitoring and recording inventories,

[128] Alpha, 2009. p. 2-31

- Manual inspections,
- Berms or dikes,
- Secondary containment,
- Monitored transfers,
- Stormwater runoff controls,
- Mechanical shut-off devices,
- Setbacks,
- Physical barriers, and
- Materials for rapid spill cleanup and recovery.

Minimization of Potential Noise and Lighting Impacts

Colorado, Louisiana, and the City of Fort Worth address noise and lighting issues. Ohio specifies that operations be conducted in a manner that mitigates noise. With respect to noise mitigation, sample requirements include:

- Ambient noise level determination prior to operations;
- Daytime and nighttime noise level limits for specified zones (in Colorado, e.g., residential/agricultural/rural, commercial, light industrial and industrial) or for distances from the wellsite, and periodic monitoring thereof;
- Site inspection and possibly sound level measurements in response to complaints;
- Direction of all exhaust sources away from building units; and
- Quiet design mufflers or equivalent equipment within 400 feet of building units.

The City of Fort Worth has much more detailed noise level requirements and also sets general work hour and day of the week guidelines for minimizing noise impacts, in consideration of the population density and urban nature of the location where the activity occurs.

Alpha found that lighting regulations, where they exist, generally require that site lighting be directed downward and internally to the extent practicable. Glare minimization on public roads and adjacent buildings is a common objective, with a target distance of 300 feet from the well in Louisiana and Fort Worth and 700 feet from the well in Colorado. Lighting impact considerations must be balanced against the safety of well site workers.

Setbacks

Alpha's setback discussion focused on water resources and private dwellings. The setback ranges in Table 5.18 were reported regarding the surveyed jurisdictions:

Table 5-18 - Water Resources and Private Dwelling Setbacks from Alpha, 2009

	Water Resources	Private Dwellings	Measured From
Arkansas	200 feet from surface waterbody or wetland, or 300 feet for streams or rivers designated as Extraordinary Resource Water, Natural and Scenic Waterway, or Ecologically Sensitive Water Body	200 feet, or 100 feet with owner's waiver	Storage tanks
Colorado	300 feet ("internal buffer;" applies only to classified water supply segments – see discussion below)	Not reported	Surface operation, including drilling, completion, production and storage
Louisiana	Not reported	500 feet, or 200 feet with owner's consent	Wellbore
New Mexico	300 feet from continuously flowing water course; 200 feet from other significant water course, lake bed, sinkhole or playa lake; 500 feet from private, domestic, fresh water wells or springs used by less than 5 households; 1000 feet from other fresh water wells or springs; 500 feet from wetland; pits prohibited within defined municipal fresh water well field or 100-year floodplain	300 feet	Any pit, including fluid storage, drilling circulation and waste disposal pits
Ohio	200 feet from private water supply wells	100 feet	Wellhead
Pennsylvania	200 feet from water supply springs and wells; 100 feet from surface water bodies and wetlands	200 feet	Well pad limits and access roads
City of Fort Worth	200 feet from fresh water well	600 feet, or 300 feet with waiver	Wellbore surface location for single-well pads; closest point on well pad perimeter for multi-well sites
Wyoming	350 feet	350 feet	Pits, wellheads, pumping units, tanks and treatment systems

Multi-Well Pad Reclamation Practices

Except for Pennsylvania, Alpha found that the surveyed jurisdictions treat multi-well pad reclamation similarly to single well pads. Pennsylvania implements requirements for best management practices to address erosion and sediment control.

As with single well pads, partial reclamation after drilling and fracturing are done would include closure of pits and revegetation of areas that are no longer needed.

Naturally Occurring Radioactive Materials (NORM)

Alpha reports that Louisiana, New Mexico and Texas currently are the three states with the most comprehensive oil and gas NORM regulatory programs. These programs, implemented within the last decade, include permitting/licensing requirements, occupational and public exposure limits, exclusion levels, handling procedures, monitoring and reporting requirements and specific disposal regulations.

Stormwater Runoff

Most of the reviewed states have stormwater runoff regulations or best management practices for oil and gas well drilling and development. Alpha suggests that Pennsylvania's approach of reducing high runoff rates and associated sediment control by inducing infiltration may be a suitable model for New York. Perimeter berms and filter fabric beneath the well pad allow infiltration of precipitation. Placement of a temporary berm across the access road entrance during a storm prevents rapid discharge down erodible access roads that slope downhill from the site.

5.18.4 Colorado's Final Amended Rules

Significant changes were made to Colorado's oil and gas rules in 2008 that became effective in spring, 2009. While many topics were addressed, the new rules related to chemical inventorying and public water supply protection are most relevant to the topics addressed by this SGEIS.

5.18.4.1 Colorado - New MSDS Maintenance and Chemical Inventory Rule

The following information is from a training presentation posted on COGCC's website.[129]

[129] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009

The new rule's objective is to assist COGCC in investigation of spills, releases, complaints and exposure incidents. The rule requires the operators to maintain a chemical inventory of chemical products brought to a well site for downhole use, *if* more than 500 pounds is used or stored at the site for downhole use or *if* more than 500 pounds of fuel is stored at the well site during a quarterly reporting period. The chemical inventory, which is *not* submitted to the COGCC unless requested, includes:

- MSDS for each chemical product;
- How much of the chemical product was used, how it was used, and when it was used;
- Identity of trade secret chemical products, but not the specific chemical constituents; and
- Maximum amount of fuel stored.

The operator must maintain the chemical inventory and make it available for inspection in a readily retrievable format at the operator's local field office for the life of the wellsite and for five years after plugging and abandonment.

MSDSs for proprietary products may not contain complete chemical compositional information. Therefore, in the case of a spill or complaint to which COGCC must respond, the vendor or service provider must provide COGCC a list of chemical constituents in any trade secret chemical product involved in the spill or complaint. COGCC may, in turn, provide the information to the Colorado Department of Public Health and Environment (CDPHE). The vendor or service provider must also disclose this list to a health professional in response to a medical emergency or when needed to diagnose and treat a patient that may have been exposed to the product. Health professionals' access to the more detailed information which is not on MSDSs is subject to a confidentiality agreement. Such information regarding trade secret products provided to the COGCC or to health professionals does not become part of the chemical inventory and is not considered public information.

5.18.4.2 Colorado - Setbacks from Public Water Supplies

The following information was provided by Alpha and supplemented from a training presentation posted on COGCC's website.[130]

Colorado's new rules require buffer zones along surface waterbodies in surface water supply areas. Buffer zones extend five miles upstream from the water supply intake and are measured from the ordinary high water line of each bank to the near edge of the disturbed area at the well location. The buffer applies to surface operations only and does not apply to areas that do not drain to classified water supply systems. The buffers are designated as internal (0-300 feet), intermediate (301-500 feet) and external (501-2,640 feet).

Activity within the internal buffer zone requires a variance and consultation with the CDPHE. Within the intermediate zone, pitless (i.e., closed loop) drilling systems are required, flowback water must be contained in tanks on the well pad or in an area with down gradient perimeter berming, and berms or other containment devices are required around production-related tanks. Pitless drilling or specified pit liner standards are required in the external buffer zone. Water quality sampling and notification requirements apply within the intermediate and external buffer zones.

5.18.5 Other States' Regulations – Conclusion

Experience in other states is similar to that of New York as a regulator of gas drilling operations. Well construction and materials handling regulations, including those pertaining to pit construction, when properly implemented and complied with, prevent environmental contamination from drilling and hydraulic fracturing activities. The reviews and surveys summarized above are informative with respect to developing enhanced mitigation measures relative to multi-well pad drilling and high-volume hydraulic fracturing. Consideration of the information presented above is reflected in Chapters 7 and 8 of this SGEIS.

[130] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009

Contents

Chapter 6 POTENTIAL ENVIRONMENTAL IMPACTS

All of the narrative in this Chapter incorporates by reference the entire 1992 Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program - including the draft volumes released in 1988, the final volume released in 1992 - and the 1992 Findings Statement. Therefore, the text in this Supplement is not exhaustive with respect to potential environmental impacts, but instead focuses on new, different or additional potential impacts related to horizontal drilling and high-volume hydraulic fracturing.

6.1 Water Resources

Protection of water resources is a primary emphasis of the Department and the oil and gas regulatory program. Water resources requiring attention with respect to horizontal drilling and high volume hydraulic fracturing are identified and discussed in Chapter 2.

SEQRA regulations state that "EISs should address only those potential significant adverse environmental impacts that can be reasonably anticipated and/or have been identified in the scoping process."[1]

Reasonably anticipated water resources impacts relate to water withdrawals for hydraulic fracturing; stormwater runoff; surface spills, leaks and pit or surface impoundment failures; groundwater impacts associated with well drilling and construction; waste disposal and New York City's subsurface water supply infrastructure. Except for NYC's subsurface water supply infrastructure, the same potential impacts exist statewide. The Department committed in the Final Scope to specifically evaluate potential surface water impacts if activity occurs in proximity to the Upper Delaware Scenic and Recreational River. Potential surface water impacts discussed herein are relative to all rivers in the prospective area for development, including but not limited to the Upper Delaware.

Two additional water resources concerns were frequently raised during the public scoping process. These were:

1) Potential degradation of New York City's surface drinking water supply; and

[1] 6 NYCRR 617.9(b)(2)

2) Potential groundwater contamination from the hydraulic fracturing procedure itself.

Because of the high level of public concern about both potential impacts, NYSERDA commissioned studies of their likelihood. As presented and summarized in Section 6.1 of this chapter, and in Chapters 7 and 8 and in Appendix 11, neither potential impact is reasonably anticipated.

6.1.1 Water Withdrawals

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies away from the well site or through wells drilled into groundwater aquifers. Without proper controls on the rate, timing and location of withdrawals, stream flow modifications could result in negative impacts to a stream's best uses, including but not limited to the aquatic ecosystem, downstream riverine and riparian resources, wetlands, and aquifer supplies.

6.1.1.1 Reduced Stream Flow

Potential effects of reduced stream flow caused by withdrawals could include:

- insufficient supplies for downstream uses such as public water supply;
- adverse impacts to quantity and quality of aquatic, wetland, and terrestrial habitats and the biota that they support; and
- exacerbation of drought effects.

Seasonally, unmitigated withdrawals could adversely impact fish and wildlife health due to exposure to unsuitable water temperature and dissolved oxygen concentrations. It could also affect downstream dischargers whose effluent limits are controlled by the stream's flow rate. Water quality could be degraded and exert greater impacts on natural aquatic habitat if existing pollutants from point sources (e.g. discharge pipes) and non-point sources (e.g. runoff from farms and paved surfaces) are not sufficiently diluted or become concentrated.

6.1.1.2 Degradation of a Stream's Best Use

New York State water use classifications are provided in Section 2.4.1. All of the uses are dependent upon sufficient water in the stream to support the specified use.

6.1.1.3 Impacts to Aquatic Habitat

Habitat for stream organisms is provided by the shape of the stream channel and the water that flows through it. It is important to recognize that the physical habitat (e.g. pools, riffles instream cover, runs, glides, bank cover, etc.) essential for maintaining the aquatic ecosystem is formed by periodic disturbances that exist in the natural hydrograph; the seasonal variability in stream flow resulting from annual precipitation and associated runoff. Maintaining this habitat diversity within a stream channel is essential in providing suitable conditions for all the life stage of the aquatic organisms. Creating and maintaining high quality habitat is a function of seasonally high flows because scour of fines from pools and deposition of bedload in riffles is most predominant at high flow associated with spring snowmelt or high rain runoff. Periodic resetting of the aquatic system is an essential process for maintaining stream habitat that will continuously provide suitable habitat for all aquatic biota. Clearly, alteration of flow regimes, sediment loads and riparian vegetation will cause changes in the morphology of stream channels. Any streamflow management decision must not impair flows necessary to maintain the dynamic nature of a river channel that is in a constant state of change as substrates are scoured, moved downstream and re-deposited.

6.1.1.4 Impacts to Aquatic Ecosystems

Aquatic ecosystems could be adversely impacted by:

- changes to water quality or quantity;
- insufficient stream flow for aquatic biota or to maintain stream habitat; or
- the actual water withdrawal infrastructure.

Improperly installed water withdrawal structures can result in the entrainment of aquatic organisms, which can remove any/all life stages of fish and macroinvertebrates from their natural habitats as they are withdrawn with water. To avoid adverse impacts to aquatic biota from entrainment, intake pipes can be screened to prevent entry into the pipe. Additionally, the loss of biota that becomes trapped on intake screens, referred to as impingement, can be minimized by properly sizing the intake to reduce the flow velocity through the screens. Transporting water from the water withdrawal location for use off-site, as discussed in Section 6.6.1, can transfer invasive species from one waterbody to another via trucks, hoses, pipelines, and other equipment. Screening of the intakes can minimize this transfer; however additional site-specific mitigation considerations may be necessary.

6.1.1.5 Impacts to Downstream Wetlands

The existence and sustainability of wetland habitats directly depend on the presence of water at or near the surface of the soil. The functioning of a wetland is driven by the inflow and outflow of surface water and/or groundwater. As a result, withdrawal of surface water or groundwater for high volume hydraulic fracturing could impact wetland resources. These potential impacts depend on the amount of water within the wetland, the amount of water withdrawn from the catchment area of the wetland, and the dynamics of water flowing into and out of the wetland. Even small changes in the hydrology of the wetland can have significant impacts on the wetland plant community and on the animals that depend on the wetland. It is important to preserve the hydrologic conditions and to understand the surface water and groundwater interaction to protect wetland areas.

6.1.1.6 Aquifer Depletion

The primary concern regarding groundwater withdrawal is aquifer depletion that could affect other uses, including nearby public and private water supply wells. This includes cumulative impacts from numerous groundwater withdrawals and potential aquifer depletion from the incremental increase in withdrawals if groundwater supplies are used for hydraulic fracturing. Aquifer depletion may also result in aquifer compaction which can result in localized ground subsidence. Aquifer depletion can occur in both confined and unconfined aquifers.

The depletion of an aquifer and a corresponding decline in the groundwater level can occur when a well, or wells in an aquifer are pumped at a rate in excess of the recharge rate to the aquifer. Essentially, surface water and groundwater are one continuous resource, therefore, it also is possible that aquifer depletion can occur if an excessive volume of water is removed from a surface water body that recharges an aquifer. Such an action would result in a reduction of recharge which could potentially deplete an aquifer. This “influent” condition of surface water recharging groundwater occurs mainly in arid and semi-arid climates, and is not common in New

York, except under conditions such as induced infiltration of surface water by aquifer withdrawal (e.g., pumping of water wells).[2]

Aquifer depletion can lead to reduced discharge of groundwater to streams and lakes, reduced water availability in wetland areas, and corresponding impacts to aquatic organisms that depend on these habitats. Flowing rivers and streams are merely a surface manifestation of what is flowing through the shallow soils and rocks. Groundwater wells impact surface water flows by intercepting groundwater that otherwise would enter a stream. In fact, many New York headwater streams rely entirely on groundwater to provide flows in the hot summer months. It is therefore important to understand the hydrologic relationship between surface water, groundwater, and wetlands within a watershed to appropriately manage rates and quantities of water withdrawal.[3]

Depletion of both groundwater and surface water can occur when water withdrawals are transported out of the basin from which they originated. These transfers break the natural hydrologic cycle, since the transported water never makes it downstream nor returns to the original watershed to help recharge the aquifer. Without the natural flow regime, including seasonal high flows, stream channel and riparian habitats critical for maintaining the aquatic biota of the stream may be adversely impacted.

6.1.1.7 Cumulative Water Withdrawal Impacts[4]

There are several potential cumulative impacts from existing water use and new withdrawals associated with natural gas development, including, but not necessarily limited to:

- Stream flow and groundwater depletion,
- Loss of aquifer storage capacity,
- Water quality degradation,

---

[2] Alpha, p. 3-19

[3] Alpha, 2009.

[4] Ibid., p. 3-28

- Fish and aquatic organism impacts,
- Significant habitats, endangered, rare or threatened species impacts,
- Existing water users and reliability of their supplies,
- Underground infrastructure.

Evaluation of cumulative impacts of multiple water withdrawals must consider the existing water usage, the non-continuous nature of withdrawals and the natural replenishment of water resources. Natural replenishment is described in Section 2.4.8.

The DRBC and SRBC have developed regulations, policies, and procedures to characterize existing water use and track approved withdrawals. Changes to these systems also require Commission review. Review of the requirements of the DRBC and SRBC indicates that the operators and the reviewing authority will perform evaluations to assess the potential impacts of water withdrawal for well drilling, and consider the following issues and information.

- Comprehensive project description that includes a description of the proposed water withdrawal (location, volume, and rate) and its intended use;
- Existing water use in the withdrawal area;
- Potential impacts, both ecological and to existing users, from the new withdrawal;
- Availability of water resources (surface water and/or groundwater) to support the proposed withdrawals;
- Availability of other water sources (e.g., treated waste water) and conservation plans to meet some or all of the water demand;
- Contingencies for low flow conditions that include passby flow criteria;
- Public notification requirements;
- Monitoring and reporting;
- Inspections;
- Mitigation measures;
- Supplemental investigations, including but not limited to, aquatic surveys;

- Potential impact to significant habitat and endangered rare or threatened species;
- Protection of subsurface infrastructure.

Existing Water Usage and Withdrawals

The DRBC and SRBC currently each use a permit system and approval process to regulate existing water usage in their respective basins. The DRBC and SRBC require applications in which operators provide a comprehensive project description that includes the description of the proposed withdrawals. The project information required includes site location, water source(s), withdrawal location(s), proposed timing and rate of water withdrawal and the anticipated project duration. The operators identify the amount of consumptive use (water not returned to the basin) and any import or export of water to or from the basin. The method of conveyance from the point(s) of withdrawal to the point(s) of use also is defined.

There are monitoring and reporting requirements once the withdrawal and consumptive use for a project has been approved. These requirements include metering withdrawals and consumptive use, and submitting quarterly reports to the Commission. Monitoring requirements can include stream flow and stage measurements for surface water withdrawals and monitoring groundwater levels for groundwater withdrawals.

Surface water and groundwater are withdrawn daily for a wide range of uses. New York ranks as one of the top states with respect to the total amount of water withdrawals. Figure 6.1 presents a graph indicating the total water withdrawal for New York is approximately 9,000 to 10,000 million gallons per day (MGD) (9 to 10 billion gallons per day), based on data from 2000.

A graph showing the maximum approved daily consumptive use of water reported by the SRBC is shown in Figure 6.2. The largest consumptive identified use is for water supply at approximately 325 million gallons per day (MGD), followed by power generation at 150 MGD, and recreation at 50 MGD.

The DRBC reports on the withdrawal of water for various purposes. The daily water withdrawals, exports, and consumptive uses in the Delaware River Basin are shown in Figure 6.3. The total water withdrawal from the Delaware River Basin was 8,736 MGD, based on 2003 water use records. The highest water use was for thermoelectric power generation at 5,682 MGD (65%), followed by 875 MGD(10%) for public water supply, 650 MGD (7.4%) for New York City, 617 MGD (7 %) for hydroelectric, and 501 MGD (5.7%) for industrial purposes. The amount of water used for mining is 70 MGD (0.8%). The "mining" category typically includes withdrawals for oil and gas drilling; however, DRBC has not yet approved water withdrawal for Marcellus shale drilling operations. The information in Figure 6.3 shows that 4.3 percent (14 MGD) of the water withdrawn for consumptive use is for mining and 88 percent (650 MGD) of water exported from the Delaware River Basin is diverted to New York City.

Whereas certain withdrawals, like many public water supplies are returned to the basin's hydrologic cycle, out-of-basin transfers, like the NYC water-supply diversion, some evaporative losses, and withdrawals for hydraulic fracturing, are considered as 100 percent consumptive losses because this water is essentially lost to the basin's hydrologic cycle.

Withdrawals for High-Volume Hydraulic Fracturing

The total volume of water to be withdrawn for horizontal well drilling and associated high volume hydraulic fracturing will not be known until applications are received and reviewed, and approved or rejected by the appropriate regulatory agency or agencies. The DRBC has received an application (Docket No. D-2009-20-1) to withdraw up to 1.0 MGD of surface water from the West Branch Delaware River to support natural gas development and extraction activities in the Delaware River Basin. The SRBC approved gas drilling and hydraulic fracturing-related surface water withdrawals up to approximately 8.86 MGD from 18 separate locations and 9.24 MGD from 19 separate locations in Pennsylvania at the March 24 and June 18, 2009 Commission meetings (SRBC, 2009). The approved volumes of the individual applications in 2009 are typical of previous withdrawals approved by the commission and range from 0.041 MGD to 3.0 MGD.

Comparison of the water withdrawal statistics with typical withdrawal volumes for natural gas drilling indicates that the historical percentage of water withdrawal for natural gas drilling is very low. The percentage of water withdrawal specifically for horizontal well drilling and high volume hydraulic fracturing also is expected to be relatively low, compared with existing everyday consumptive water losses. Figure 6.2 shows that the "current estimate" of water use for gas drilling is approximately 30 MGD in the Susquehanna River Basin, or less than 6 percent of the total use for water supply, power, and recreation.

Figure 6.1 – Water Withdrawals in the United States

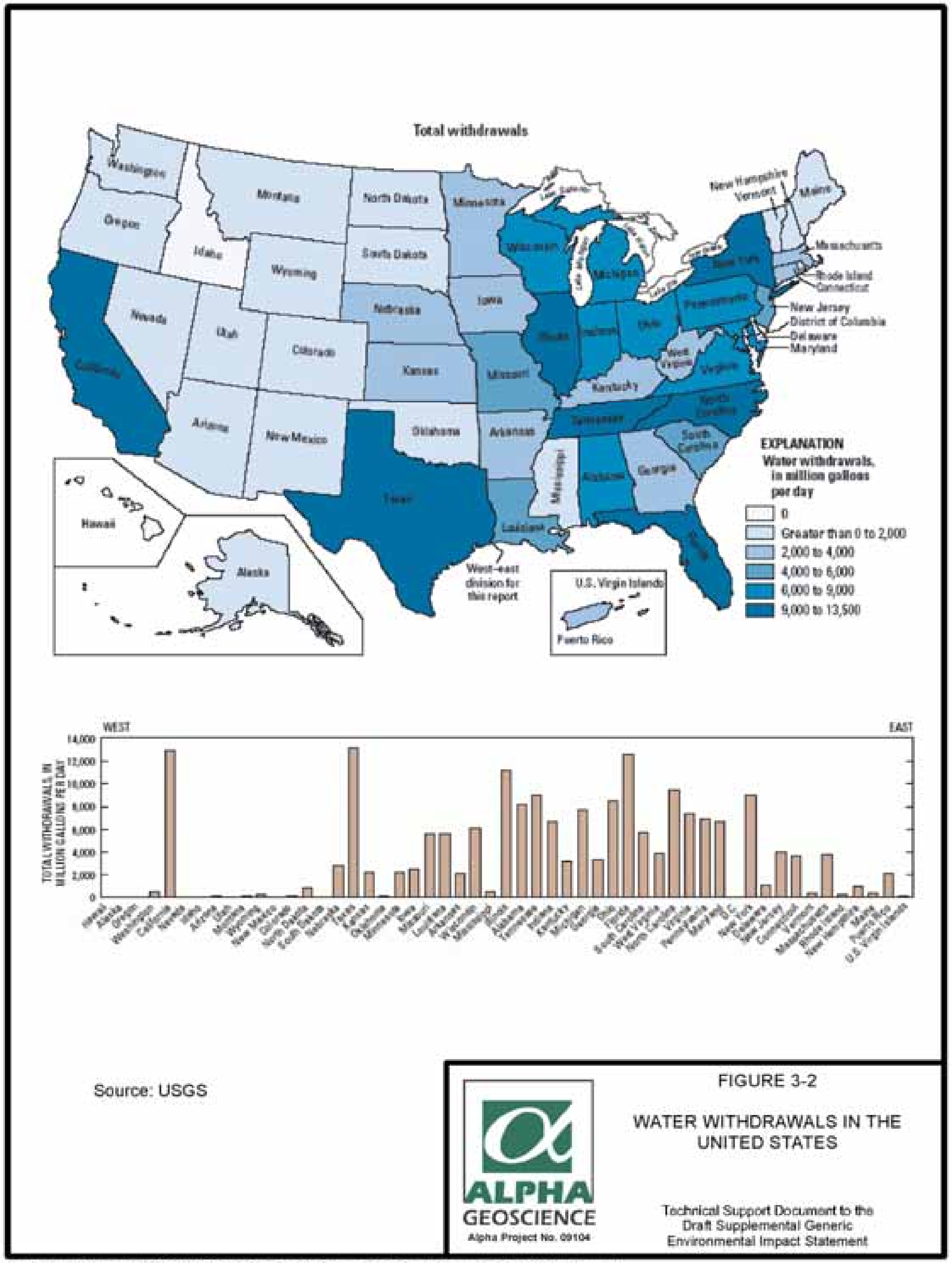


Figure 6.2 - Maximum Approved Daily Consumptive Use in the Susquehanna River Basin

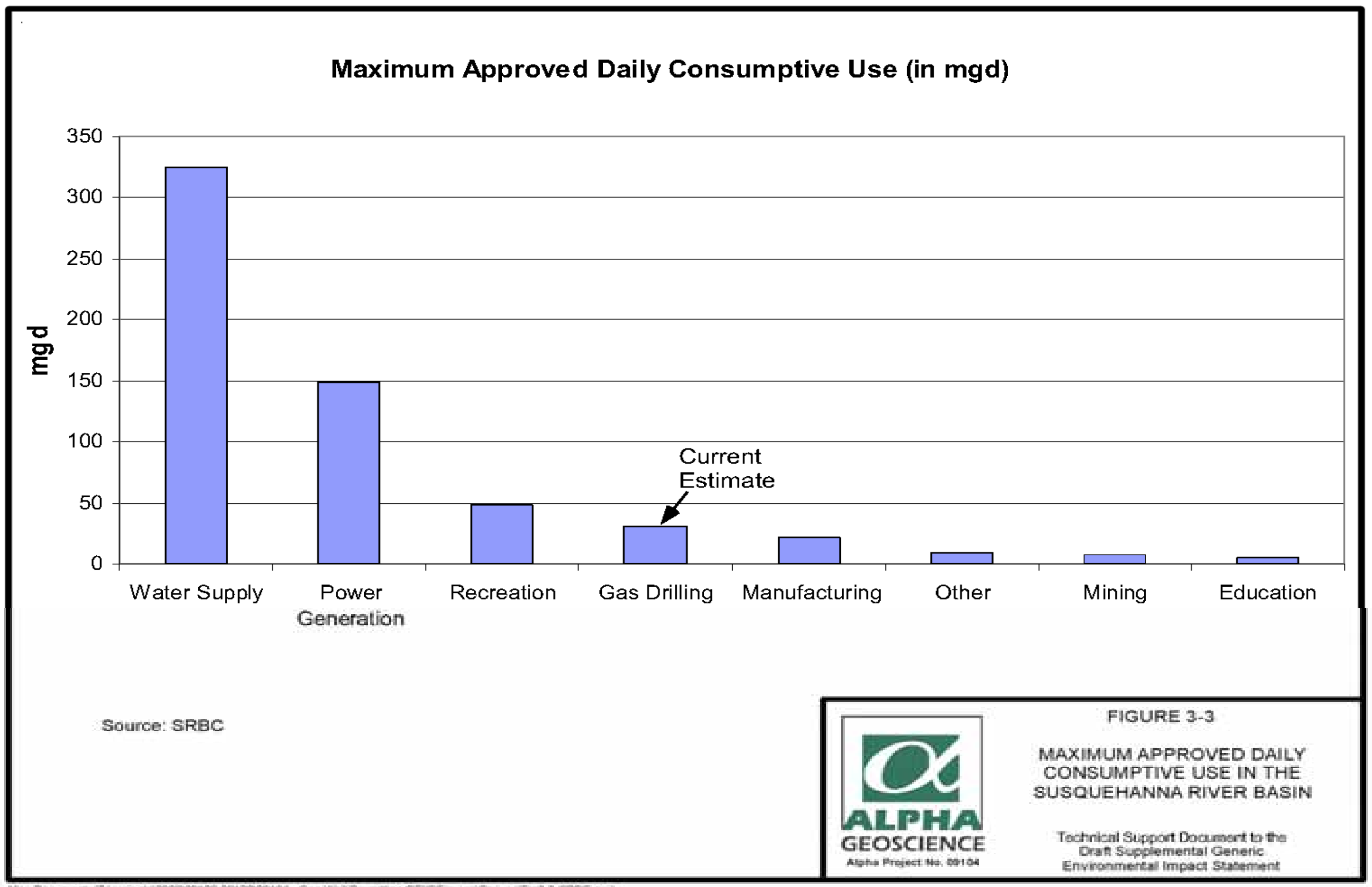
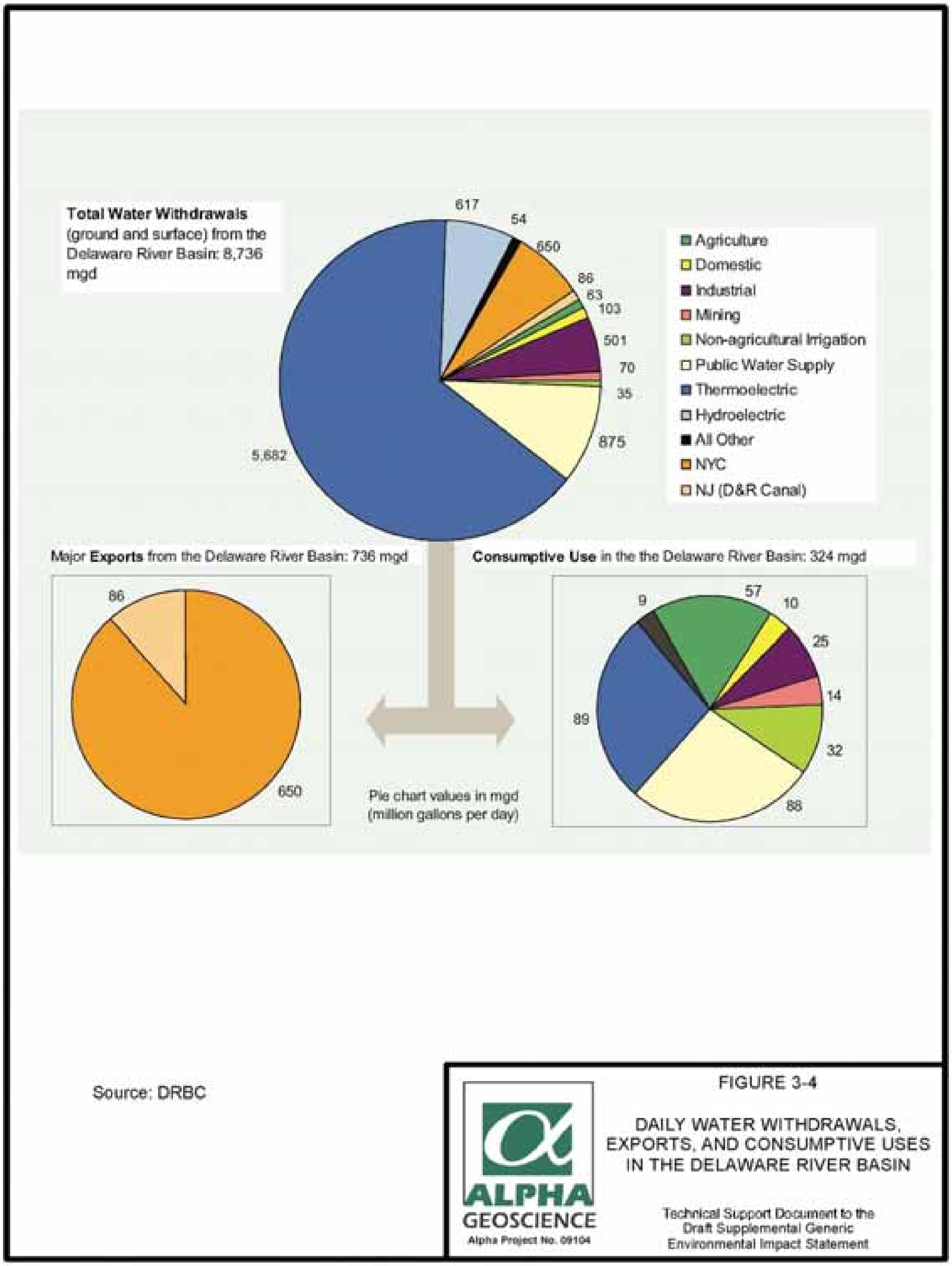


Figure 6.3 - Daily Water Withdrawals, Exports, and Consumptive Uses in the Delaware River Basin



6.1.2 Stormwater Runoff

Stormwater runoff, whether as a result of rain fall or snow melt, is a valuable resource. It is the source water for lakes and streams, as well as groundwater aquifers. However, stormwater runoff is also a pathway for contaminants to be conveyed from the land surface to streams and lakes and groundwater. This is especially true for asphalt, concrete, gravel/dirt roads and other impervious surfaces, where any material collected on the ground is then washed away to a nearby surface water body, or from intensive outdoor construction and industrial activity where materials and products are exposed to rainfall. In severe cases, stormwater runoff may also cause flooding problems.

On an undisturbed landscape, runoff is retarded by vegetation and top soil, allowing it to slowly filter into the ground. This benefits water resources by using natural filtering properties, replenishing groundwater aquifers and feeding lakes and streams during dry periods. On a disturbed or developed landscape, it is common for the ground surface to be compacted or otherwise made less pervious and for runoff to be shunted away more quickly. Such hydrological modifications result in less groundwater recharge and more rapid runoff to streams, which may cause increased stream erosion and result in water quality degradation, habitat loss and flood damage.

All phases of natural gas well development, from initial land clearing for access roads, equipment staging areas and well pads, to drilling and fracturing operations, production and final reclamation, have the potential to cause water resource impacts during rain and snow melt events if stormwater is not properly managed.

Initial land clearing exposes soil to erosion and more rapid runoff. Construction equipment is a potential source of contamination from such things as hydraulic, fuel and lubricating fluids. Equipment and any materials that are spilled, including additive chemicals and fuel, are exposed to rainfall, so that contaminants may be conveyed off-site during rain events if they are not properly contained. Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pit is proposed.

A production site, including access roads, is also a potential source of stormwater runoff impacts because its hydrological characteristics may be substantially different from the pre-developed condition. There is a greater potential for stormwater impacts from a larger well pad during the production phase, compared with a smaller well pad for a single vertical well.

6.1.3 Surface Spills and Releases at the Well Pad

Spills or releases can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers.

6.1.3.1 Drilling

Contamination of surface water bodies and groundwater resources during well drilling could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor casing construction, or accidental spills and releases. Surface spills would involve materials and fluids present at the site during the drilling phase. Pit leakage or failure could also involve well fluids. These issues are discussed in Chapters 8 and 9 of the GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. GEIS conclusions regarding pit construction standards and liner specifications were largely based upon the short duration of a pit's use. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the odds of an accidental spill, pit leak or pit failure if mitigation measures are not sufficiently durable. Concerns are heightened if on-site pits for handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad.

6.1.3.2 Hydraulic Fracturing Additives

As with the drilling phase, contamination of surface water bodies and groundwater resources during well stimulation could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor well construction and grouting, or accidental spills and releases. These issues are discussed in Chapters 8 and 9 of the GEIS, but are acknowledged again here because of the larger volumes of fluids and materials to be managed for high-volume hydraulic fracturing. The potential contaminants are listed in Table 5.6 and grouped into categories determined by NYSDOH in Table 5.7. URS compared the list of additive chemicals to the parameters regulated via primary or secondary drinking water standards, SPDES discharge limits (see Section 7.1.8), and Division of Water Technical and Operational Guidance Series 1.1.1 (TOGS111), *Ambient Water Quality Standards and Guidance Values and Groundwater Effluent Limitations.*[5,6] See Table 6.1.

6.1.3.3 Flowback Water

Gelling agents, surfactants and chlorides are identified in the GEIS as the flowback water components of greatest environmental concern.[7] Other flow back components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. Opportunities for spills, leaks, operational errors, and pit or surface impoundment failures during the flowback water recovery stage are the same as they are during the prior stages with the additional potential of releases from:

- hoses or pipes used to convey flowback water to tanks, an on-site pit, a centralized surface impoundment, or a tanker truck for transportation to a treatment or disposal site; and

- tank leakage or failure of a pit or surface impoundment to effectively contain fluid.

Flowback water composition based on a limited number of out-of-state samples from Marcellus wells is presented in Table 5.9. A summary by chemical category prepared by NYSDOH is presented in Section 5.11.3.2. A comparison of detected flowback parameters, except radionuclides, to regulated parameters is presented in Table 6.1[8]

Table 6.2 lists parameters found in the flowback analyses, except radionuclides, that are regulated in New York. The number of samples that were analyzed for the particular parameter is shown in Column 3, and the number of samples in which parameters were detected is shown in

---

[5] URS, p. 4-18, et seq.

[6] http://www.dec.ny.gov/regulations/2652.html

[7] GEIS, p. 9-37

[8] URS, p. 4-18, et seq.

Column 4. The minimum, median and maximum concentrations detected are indicated in Columns 5, 6 and 7.[9]

Radionuclides data is presented in Chapter 5, and potential impacts and regulation are discussed in Section 6.8.

Table 6.3 lists parameters found in the flowback analyses that are not regulated in New York. Column 2 shows the number of samples that analyzed for the particular parameter; column 3 indicates the number in which the parameter was detected.[10]

Information presented in Tables 6.2 and 6.3 are based on limited data from Pennsylvania and West Virginia. Samples were not collected specifically for this type of analysis or under DEC's oversight. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. The raw data for these tables came from several sources, with likely varying degrees of reliability, and the analytical methods used were not all the same for given parameters. Sometimes, laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days after the well is fractured. This data does not control for any of these variables.[11]

[9] URS, pp. 4-10, 4-31 et seq.

[10] URS, pp. 4-10, p. 4-35

[11] URS, p. 4-31

Table 6.1 – Comparison of additives used or proposed for use in NY, parameters detected in analytical results of flowback from the Marcellus operations in PA and WV, and parameters regulated via primary and secondary drinking water standards, SPDES or TOGS111

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	1,1,1-Trifluorotoluene		Yes				
02634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one	Yes					
00095-63-6	1,2,4 trimethylbenzene	Yes				Table 9	Tables 1,5
00123-91-1	1,4 Dioxane	Yes				Table 8	
	1,4-Dichlorobutane		Yes			Table 10	
03452-07-1	1-eicosene	Yes					
00629-73-2	1-hexadecene	Yes					
00112-88-9	1-octadecene	Yes					
01120-36-1	1-tetradecene	Yes					
10222-01-2	2,2 Dibromo-3-nitrilopropionamide	Yes				Table 9	Tables 1,5
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	Yes					
73003-80-2	2,2-Dobromomalonamide	Yes					
	2,4,6-Tribromophenol		Yes			Table 6	Tables 1,5
	2,5-Dibromotoluene		Yes				
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer	Yes					
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride	Yes					
00052-51-7	2-Bromo-2-nitro-1,3-propanediol	Yes				Table 10	
00111-76-2	2-Butoxy ethanol	Yes					

12 As with Table 5.6, information in the “Used in Additives” column is based on the composition of additives used or proposed for use in New York.

13 As with Table 5.8, information in the “Found in Flowback” column is based on analytical results of flowback from operations in Pennsylvania or West Virginia. There are/may be products used in fracturing operations in Pennsylvania that have not yet been proposed for use in New York for which, therefore, the NYSDEC does not have chemical composition data.

14 Limits marked with a pound sign (#) are based on secondary drinking water standards.

15 SPDES or TOGS typically regulates or provides guidance for the total substance, e.g. iron; and rarely regulates or provides guidance for only its dissolved portion, e.g. dissolved iron. The dissolved component is implicitly covered in the total substance. Therefore, the dissolved component is not included in Table 4-4. Flowback analyses provided information for the total and dissolved components of metals, which are listed in Table 3-1. Understanding the dissolved vs. suspended portions of a substance is valuable when determining potential treatment techniques.

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
01113-55-9	2-Dibromo-3-Nitriloprionamide (2-Monobromo-3-nitriilopropionamide)	Yes					
00104-76-7	2-Ethyl Hexanol	Yes					
	2-Fluorobiphenyl		Yes			Table 6	Tables 1,5
	2-Fluorophenol		Yes			Table 6	Tables 1,5
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol	Yes				Table 10	
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer	Yes					
09003-03-6	2-propenoic acid, homopolymer, ammonium salt	Yes					
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate	Yes					
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)	Yes					
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite	Yes					
00107-19-7	2-Propyn-1-ol / Progargyl Alcohol	Yes					
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,	Yes					
00115-19-5	3-methyl-1-butyn-3-ol	Yes					
00056-57-5	4-Nitroquinoline-1 -oxide		Yes			Table 8	
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol	Yes					
	4-Terphenyl-d14		Yes			Table 6	Tables 1,5
00064-19-7	Acetic acid	Yes				Table 10	
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	Yes					
00108-24-7	Acetic Anhydride	Yes				Table 10	
00067-64-1	Acetone	Yes	Yes			Table 7	Tables 1,5
00079-06-1	Acrylamide	Yes		0	TT	Table 9	Tables 1,5
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	Yes					
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide	Yes					
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					
15085-02-3	Acrylamide-sodium acrylate copolymer	Yes					
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)	Yes					
	Aliphatic acids	Yes					
	Aliphatic alcohol glycol ether	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent	Yes					
	Alkalinity, Carbonate, as CaCO3		Yes			Table 10	
64743-02-8	Alkenes	Yes					
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt	Yes					
	Alkyl Aryl Polyethoxy Ethanol	Yes					
	Alkylaryl Sulfonate	Yes					
09016-45-9	Alkylphenol ethoxylate surfactants	Yes		0.5 mg/L#			
07439-90-5	Aluminum		Yes	0.05 to 0.2 mg/L#		Table 7	Tables 1,5
01327-41-9	Aluminum chloride	Yes					
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated	Yes					
71011-04-6	Amines, Ditallow alkyl, ethoxylated	Yes					
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates	Yes					
01336-21-6	Ammonia	Yes				Yes	
00631-61-8	Ammonium acetate	Yes				Table 10	
68037-05-8	Ammonium Alcohol Ether Sulfate	Yes					
07783-20-2	Ammonium bisulfate	Yes					
10192-30-0	Ammonium Bisulphite	Yes					
12125-02-9	Ammonium Chloride	Yes				Table 10	
07632-50-0	Ammonium citrate	Yes					
37475-88-0	Ammonium Cumene Sulfonate	Yes					
01341-49-7	Ammonium hydrogen-difluoride	Yes					
06484-52-2	Ammonium nitrate	Yes					
07727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate	Yes					
01762-95-4	Ammonium Thiocyanate	Yes				Table 10	
07440-36-0	Antimony		Yes	0.006	0.006	Table 6	Tables 1,5
07664-41-7	Aqueous ammonia	Yes	Yes			Table 7	Tables 1,5
	Aromatic hydrocarbons	Yes					
	Aromatic ketones	Yes					
07440-38-2	Arsenic		Yes	0	0.01	Table 6	Tables 1,5
07440-39-3	Barium		Yes	2	2	Table 7	Tables 1,5
	Barium Strontium P.S. (mg/L)		Yes				

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay	Yes					
00071-43-2	Benzene	Yes	Yes	0	0.005	Table 6	Tables 1,5
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	Yes					
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	Yes					
	Bicarbonates (mg/L)		Yes			Table 10	
	Biochemical Oxygen Demand		Yes			Yes	
00117-81-7	Bis(2-ethylhexyl)phthalate		Yes	0	0.006	Table 6	Tables 1,5
10043-35-3	Boric acid	Yes					
01303-86-2	Boric oxide / Boric Anhydride	Yes					
07440-42-8	Boron		Yes			Table 7	Tables 1,5
24959-67-9	Bromide		Yes			Table 7	Tables 1,5
00075-25-2	Bromoform		Yes			Table 6	Tables 1,5
00071-36-3	Butan-1-ol	Yes				Table 10	Tables 1,5
68002-97-1	C10 - C16 Ethoxylated Alcohol	Yes					
68131-39-5	C12-15 Alcohol, Ethoxylated	Yes					
07440-43-9	Cadmium		Yes	0.005	0.005	Table 6	Tables 1,5
07440-70-2	Calcium		Yes			Table 8	
10043-52-4	Calcium chloride	Yes					
00124-38-9	Carbon Dioxide	Yes					
68130-15-4	Carboxymethylhydroxypropyl guar	Yes					
09012-54-8	Cellulase / Hemicellulase Enzyme	Yes					
09004-34-6	Cellulose	Yes					
	Chemical Oxygen Demand		Yes			Yes	
	Chloride		Yes	250 mg/L[#]		Table 7	Tables 1,5
10049-04-4	Chlorine Dioxide	Yes		MRDLG=0.8	MRDL=0.8	Table 10	
00124-48-1	Chlorodibromomethane		Yes			Table 6	Tables 1,5
07440-47-3	Chromium		Yes	0.1	0.1	Table 6	Tables 1,5
00077-92-9	Citric Acid	Yes					
94266-47-4	Citrus Terpenes	Yes					
07440-48-4	Cobalt		Yes			Table 7	Table 1
61789-40-0	Cocamidopropyl Betaine	Yes					
68155-09-9	Cocamidopropylamine Oxide	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
68424-94-2	Coco-betaine	Yes					
	Color		Yes	15 (Color Units)#		Table 7	
07440-50-8	Copper		Yes	1.0#	TT; Action Level=1.3	Table 6	Tables 1,5
07758-98-7	Copper (II) Sulfate	Yes					
31726-34-8	Crissanol A-55	Yes					
14808-60-7	Crystalline Silica (Quartz)	Yes					
07447-39-4	Cupric chloride dihydrate	Yes					
00057-12-5	Cyanide		Yes	0.2	0.2	Table 6	Tables 1,5
01120-24-7	Decyldimethyl Amine	Yes					
02605-79-0	Decyl-dimethyl Amine Oxide	Yes					
03252-43-5	Dibromoacetonitrile	Yes				Table 9	Tables 1
00075-27-4	Dichlorobromomethane		Yes			Table 6	Tables 1,5
25340-17-4	Diethylbenzene	Yes					
00111-46-6	Diethylene Glycol	Yes				Table 10	
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt	Yes					
28757-00-8	Diisopropyl naphthalenesulfonic acid	Yes					
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt	Yes					
07398-69-8	Dimethyldiallylammonium chloride	Yes					
25265-71-8	Dipropylene glycol	Yes					
00139-33-3	Disodium Ethylene Diamine Tetra Acetate	Yes					
05989-27-5	D-Limonene	Yes					
00123-01-3	Dodecylbenzene	Yes					
27176-87-0	Dodecylbenzene sulfonic acid	Yes					
42504-46-1	Dodecylbenzenesulfonate isopropanolamine	Yes					
00050-70-4	D-Sorbitol / Sorbitol	Yes					
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase	Yes					
149879-98-1	Erucic Amidopropyl Dimethyl Betaine	Yes					
00089-65-6	Erythorbic acid, anhydrous	Yes					
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	Yes					
00107-21-1	Ethane-1,2-diol / Ethylene Glycol	Yes				Table 7	Tables 1,5

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
09002-93-1	Ethoxylated 4-tert-octylphenol	Yes					
68439-50-9	Ethoxylated alcohol	Yes					
126950-60-5	Ethoxylated alcohol	Yes					
68951-67-7	Ethoxylated alcohol (C14-15)	Yes					
68439-46-3	Ethoxylated alcohol (C9-11)	Yes					
66455-15-0	Ethoxylated Alcohols	Yes					
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)	Yes					
68439-51-0	Ethoxylated Alcohols (C12-14)	Yes					
78330-21-9	Ethoxylated branch alcohol	Yes					
34398-01-1	Ethoxylated C11 alcohol	Yes					
61791-12-6	Ethoxylated Castor Oil	Yes					
61791-29-5	Ethoxylated fatty acid, coco	Yes					
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine	Yes					
68439-45-2	Ethoxylated hexanol	Yes					
09036-19-5	Ethoxylated octylphenol	Yes					
09005-67-8	Ethoxylated Sorbitan Monostearate	Yes					
09004-70-3	Ethoxylated Sorbitan Trioleate	Yes					
00064-17-5	Ethyl alcohol / ethanol	Yes					
00100-41-4	Ethyl Benzene	Yes	Yes	0.7	0.7	Table 6	Tables 1,5
00097-64-3	Ethyl Lactate	Yes					
09003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)	Yes					
00075-21-8	Ethylene oxide	Yes				Table 9	Tables 1,5
05877-42-9	Ethyloctynol	Yes					
68526-86-3	Exxal 13	Yes					
61790-12-3	Fatty Acids	Yes					
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	Yes					
09043-30-5	Fatty alcohol polyglycol ether surfactant	Yes		0.5 mg/L[#]			
07705-08-0	Ferric chloride	Yes				Table 10	
07782-63-0	Ferrous sulfate, heptahydrate	Yes					
16984-48-8	Fluoride		Yes	2[#]	4	Table 7	Tables 1,5
00050-00-0	Formaldehyde	Yes				Table 8	Tables 1,5

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	Yes					
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	Yes					
00075-12-7	Formamide	Yes					
00064-18-6	Formic acid	Yes				Table 10	
00110-17-8	Fumaric acid	Yes				Table 10	
65997-17-3	Glassy calcium magnesium phosphate	Yes					
00111-30-8	Glutaraldehyde	Yes					
00056-81-5	Glycerol / glycerine	Yes					
09000-30-0	Guar Gum	Yes					
64742-94-5	Heavy aromatic petroleum naphtha	Yes					
09025-56-3	Hemicellulase	Yes					
07647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid	Yes					
07722-84-1	Hydrogen Peroxide	Yes				Table 10	
00079-14-1	Hydroxy acetic acid	Yes					
35249-89-9	Hydroxyacetic acid ammonium salt	Yes					
09004-62-0	Hydroxyethyl cellulose	Yes					
05470-11-1	Hydroxylamine hydrochloride	Yes					
39421-75-5	Hydroxypropyl guar	Yes					
07439-89-6	Iron		Yes	0.3 mg/L[#]		Table 7	Tables 1,5
35674-56-7	Isomeric Aromatic Ammonium Salt	Yes					
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic	Yes					
00064-63-0	Isopropanol	Yes				Table 10	
00098-82-8	Isopropylbenzene (cumene)	Yes				Table 9	Tables 1,5
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	Yes					
08008-20-6	Kerosene	Yes					
64742-81-0	Kerosine, hydrodesulfurized	Yes					
00063-42-3	Lactose	Yes					
07439-92-1	Lead		Yes	0	TT; Action Level 0.015	Table 6	Tables 1,5
64742-95-6	Light aromatic solvent naphtha	Yes					
01120-21-4	Light Paraffin Oil	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	Lithium		Yes			Table 10	
07439-95-4	Magnesium		Yes			Table 7	Tables 1,5
14807-96-6	Magnesium Silicate Hydrate (Talc)	Yes					
07439-96-5	Manganese		Yes	0.05 mg/L#		Table 7	Tables 1,5
01184-78-7	Methanamine, N,N-dimethyl-, N-oxide	Yes					
00067-56-1	Methanol	Yes				Table 10	
00074-83-9	Methyl Bromide		Yes			Table 6	Tables 1,5
00074-87-3	Methyl Chloride		Yes	0	0.005	Table 6	Tables 1,5
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	Yes					
08052-41-3	Mineral spirits / Stoddard Solvent	Yes					
07439-98-7	Molybdenum		Yes			Table 7	
00141-43-5	Monoethanolamine	Yes					
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					
64742-48-9	Naphtha (petroleum), hydrotreated heavy	Yes					
00091-20-3	Naphthalene	Yes	Yes			Table 6	Tables 1,5
38640-62-9	Naphthalene bis(1-methylethyl)	Yes					
00093-18-5	Naphthalene, 2-ethoxy-	Yes					
68909-18-2	N-benzyl-alkyl-pyridinium chloride	Yes					
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	Yes					
07440-02-0	Nickel		Yes			Table 6	Tables 1,5
	Nitrobenzene-d5		Yes				
07727-37-9	Nitrogen, Liquid form	Yes					
	Nitrogen, Total as N		Yes				Table 5
68412-54-4	Nonylphenol Polyethoxylate	Yes					
	Oil and Grease		Yes				Table 5
121888-66-2	Organophilic Clays	Yes					
	O-Terphenyl		Yes			Table 6	Tables 1,5
	Oxyalkylated alkylphenol	Yes					
64742-65-0	Petroleum Base Oil	Yes					
	Petroleum distillate blend	Yes					
	Petroleum hydrocarbons		Yes				

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
64741-68-0	Petroleum naphtha	Yes					
	pH		Yes	6.5-8.5[#]			Table 5
00108-95-2	Phenol		Yes			Table 6	Tables 1,5
	Phenol-d5		Yes				
	Phenols		Yes			Table 6	Tables 1,5
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt	Yes					
57723-14-0	Phosphorus		Yes			Table 7	Table 1
08000-41-7	Pine Oil	Yes					
24938-91-8	Poly(oxy-1,2-ethanediyl), ?-tridecyl-?-hydroxy-	Yes					
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-	Yes					
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol	Yes					
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized	Yes					
56449-46-8	polyethlene glycol oleate ester	Yes					
	Polyethoxylated alkanol	Yes					
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate	Yes					
	Polymeric Hydrocarbons	Yes					
09005-65-6	Polyoxyethylene Sorbitan Monooleate	Yes					
61791-26-2	Polyoxylated fatty amine salt	Yes					
07440-09-7	Potassium		Yes			Table 8	
00127-08-2	Potassium acetate	Yes					
12712-38-8	Potassium borate	Yes					
00584-08-7	Potassium carbonate	Yes					
07447-40-7	Potassium chloride	Yes					
00590-29-4	Potassium formate	Yes					
01310-58-3	Potassium Hydroxide	Yes				Table 10	
13709-94-9	Potassium metaborate	Yes					
24634-61-5	Potassium Sorbate	Yes					
112926-00-8	Precipitated silica / silica gel	Yes					
00057-55-6	Propane-1,2-diol, or Propylene glycol	Yes					Tables 1,5
00107-98-2	Propylene glycol monomethyl ether	Yes				Table 10	
68953-58-2	Quaternary Ammonium Compounds	Yes				Table 9	Tables 1

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
62763-89-7	Quinoline,2-methyl-, hydrochloride	Yes					
15619-48-4	Quinolinium, 1-(phenylmethl),chloride	Yes					
	Salt of amine-carbonyl condensate	Yes					
	Salt of fatty acid/polyamine reaction product	Yes					
	Scale Inhibitor (mg/L)		Yes				
07782-49-2	Selenium		Yes	0.05	0.05	Table 6	Tables 1,5
07631-86-9	Silica, Dissolved	Yes				Table 8	
07440-22-4	Silver		Yes	0.10 mg/L[#]		Table 6	Tables 1,5
07440-23-5	Sodium		Yes			Table 7	Tables 1,5
05324-84-5	Sodium 1-octanesulfonate	Yes					
00127-09-3	Sodium acetate	Yes					
95371-16-7	Sodium Alpha-olefin Sulfonate	Yes					
00532-32-1	Sodium Benzoate	Yes					
00144-55-8	Sodium bicarbonate	Yes					
07631-90-5	Sodium bisulfate	Yes					
07647-15-6	Sodium Bromide	Yes					
00497-19-8	Sodium carbonate	Yes					
07647-14-5	Sodium Chloride	Yes					
07758-19-2	Sodium chlorite	Yes					
03926-62-3	Sodium Chloroacetate	Yes					
00068-04-2	Sodium citrate	Yes					
06381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt	Yes					
02836-32-0	Sodium Glycolate	Yes					
01310-73-2	Sodium Hydroxide	Yes				Table 10	
07681-52-9	Sodium hypochlorite	Yes				Table 10	
07775-19-1	Sodium Metaborate .8H2O	Yes					
10486-00-7	Sodium perborate tetrahydrate	Yes					
07775-27-1	Sodium persulphate	Yes					
09003-04-7	Sodium polyacrylate	Yes					
07757-82-6	Sodium sulfate	Yes				Table 10	
01303-96-4	Sodium tetraborate decahydrate	Yes					
07772-98-7	Sodium Thiosulfate	Yes					
01338-43-8	Sorbitan Monooleate	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	Specific Conductivity		Yes				
07440-24-6	Strontium		Yes			Table 9	Table 1
00057-50-1	Sucrose	Yes					
	Sugar	Yes					
05329-14-6	Sulfamic acid	Yes					
14808-79-8	Sulfate		Yes	250 mg/L[#]		Table 7	Tables 1,5
	Sulfide		Yes			Table 7	Tables 1,5
14265-45-3	Sulfite		Yes			Table 7	Table 1
	Surfactant blend	Yes		0.5 mg/L[#]			
	Surfactants MBAS		Yes	0.5 mg/L[#]			
112945-52-5	Syntthetic Amorphous / Pyrogenic Silica / Amorphous Silica	Yes					
68155-20-4	Tall Oil Fatty Acid Diethanolamine	Yes					
08052-48-0	Tallow fatty acids sodium salt	Yes					
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized	Yes					
68647-72-3	Terpene and terpenoids	Yes					
68956-56-9	Terpene hydrocarbon byproducts	Yes					
00127-18-4	Tetrachloroethylene		Yes	0	0.005	Table 6	Tables 1,5
00533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)	Yes					
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	Yes					
00075-57-0	Tetramethyl ammonium chloride	Yes					
00064-02-8	Tetrasodium Ethylenediaminetetraacetate	Yes					
07440-28-0	Thallium		Yes	0.0005	0.002	Table 6	Tables 1,5
00068-11-1	Thioglycolic acid	Yes					
00062-56-6	Thiourea	Yes				Table 10	
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	Yes					
07440-32-6	Titanium		Yes			Table 7	
00108-88-3	Toluene	Yes	Yes	1	1	Table 6	Tables 1,5
	Total Dissolved Solids		Yes	500 mg/L[#]			Table 5
	Total Kjeldahl Nitrogen		Yes			Yes	
	Total Organic Carbon		Yes			Yes	
	Total Suspended Solids		Yes			Yes	
81741-28-8	Tributyl tetradecyl phosphonium chloride	Yes					
68299-02-5	Triethanolamine hydroxyacetate	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
00112-27-6	Triethylene Glycol	Yes					
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated	Yes					
00150-38-9	Trisodium Ethylenediaminetetraacetate	Yes					
05064-31-3	Trisodium Nitrilotriacetate	Yes					
07601-54-9	Trisodium ortho phosphate	Yes					
00057-13-6	Urea	Yes					
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer	Yes					
	Xylenes		Yes	10	10		Tables 1,5
07440-66-6	Zinc		Yes	5 mg/L[#]		Table 6	Tables 1,5
	Zirconium		Yes				

Table 6.2– Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[16]

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	1,4-Dichlorobutane	1	1	198	198	198	%REC
	2,4,6-Tribromophenol[17]	1	1	101	101	101	%REC
	2-Fluorobiphenyl[18]	1	1	71	71	71	%REC
	2-Fluorophenol[19]	1	1	72.3	72.3	72.3	%REC
00056-57-5	4-Nitroquinoline-1 -oxide	24	24	1422	13908	48336	mg/L
	4-Terphenyl-d14 [20]	1	1	44.8	44.8	44.8	%REC
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Alkalinity, Carbonate, as CaCO3	31	9	4.9	91	117	mg/L
07439-90-5	Aluminum	29	3	0.08	0.09	1.2	mg/L
07440-36-0	Antimony	29	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	28	25	12.4	58.1	382	mg/L
07440-38-2	Arsenic	29	2	0.09	0.1065	0.123	mg/L
07440-39-3	Barium	34	34	0.553	661.5	15700	mg/L
00071-43-2	Benzene	29	14	15.7	479.5	1950	µg/L
	Bicarbonates [21]	24	24	0	564.5	1708	mg/L
	Biochemical Oxygen Demand	29	28	3	274.5	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	23	2	10.3	15.9	21.5	µg/L

[16] Information presented in Table 6.1 and Table 6.3 are based on limited data from Pennsylvania and West Virginia. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. In addition, the raw data for these tables came from several sources, with likely varying degrees of reliability. Also, the analytical methods used were not all the same for given parameters. Sometimes laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days soon after the well is fractured. This data does not control for any of these variables.

[17] Regulated under phenols.

[18] Regulated under phenols.

[19] Regulated under phenols.

[20] Regulated under phenols.

[21] Regulated under alkalinity.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
07440-42-8	Boron	26	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	6	6	11.3	616	3070	mg/L
00075-25-2	Bromoform	29	2	34.8	36.65	38.5	µg/L
07440-43-9	Cadmium	29	5	0.009	0.032	1.2	mg/L
07440-70-2	Calcium	55	52	29.9	5198	34000	mg/L
	Chemical Oxygen Demand	29	29	1480	5500	31900	mg/L
	Chloride	58	58	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	29	2	3.28	3.67	4.06	µg/L
07440-47-3	Chromium	29	3	0.122	5	5.9	mg/L
07440-48-4	Cobalt	25	4	0.03	0.3975	0.58	mg/L
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	29	4	0.01	0.035	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	µg/L
00100-41-4	Ethyl Benzene	29	14	3.3	53.6	164	µg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	58	34	0	47.9	810	mg/L
07439-92-1	Lead	29	2	0.02	0.24	0.46	mg/L
	Lithium	25	4	34.4	55.75	161	mg/L
07439-95-4	Magnesium	58	46	9	563	3190	mg/L
07439-96-5	Manganese	29	15	0.292	2.18	14.5	mg/L
00074-83-9	Methyl Bromide	29	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	29	1	15.6	15.6	15.6	µg/L
07439-98-7	Molybdenum	25	3	0.16	0.72	1.08	mg/L
00091-20-3	Naphthalene	26	1	11.3	11.3	11.3	µg/L
07440-02-0	Nickel	29	6	0.01	0.0465	0.137	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	25	9	5	17	1470	mg/L
	o-Terphenyl [22]	1	1	91.9	91.9	91.9	%Rec
	pH	56	56	1	6.2	8	S.U.
00108-95-2	Phenol	23	1	459	459	459	µg/L
	Phenols	25	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L

[22] Regulated under phenols.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
07440-09-7	Potassium	31	13	59	206	7810	mg/L
07782-49-2	Selenium	29	1	0.058	0.058	0.058	mg/L
07440-22-4	Silver	29	3	0.129	0.204	6.3	mg/L
07440-23-5	Sodium	31	28	83.1	19650	96700	mg/L
07440-24-6	Strontium	30	27	0.501	821	5841	mg/L
14808-79-8	Sulfate (as SO4)	58	45	0	3	1270	mg/L
	Sulfide (as S)	3	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO3)	3	3	2.56	64	64	mg/L
	Surfactants [23]	3	3	0.2	0.22	0.61	mg/L
00127-18-4	Tetrachloroethylene	29	1	5.01	5.01	5.01	µg/L
07440-28-0	Thallium	29	1	0.1	0.1	0.1	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	29	15	2.3	833	3190	µg/L
	Total Dissolved Solids	58	58	1530	93200	337000	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [24]	23	23	69.2	449	1080	mg/L
	Total Suspended Solids	29	29	30.6	146	1910	mg/L
	Xylenes	22	14	16	487	2670	µg/L
07440-66-6	Zinc	29	6	0.028	0.048	0.09	mg/L

[23] Regulated under foaming agents.

[24] Regulated via BOD, COD and the different classes/compounds of organic carbon.

Table 6.3 - Detected flowback parameters not regulated in New York. Data from limited PA and WV flowback analyses.

Parameter Name [25]	Total Number of Samples	Detects
1,1,1-Trifluorotoluene	1	1
2,5-Dibromotoluene	1	1
Barium Strontium P.S.	24	24
Nitrobenzene-d5	1	1
Scale Inhibitor	24	24
Zirconium	22	1

With respect to surface spills, leaks and container failures, the durability concerns discussed above apply and are magnified by the potential use of large centralized surface impoundments that could be in use for several years, with fluids transferred by pipes laid along the ground. In addition, the large volume of flowback water that may be present at either a well pad or a centralized site increases the importance of appropriate practices, control measures and contingency plans.

6.1.4 Groundwater Impacts Associated With Well Drilling and Construction

The wellbore being drilled, completed or produced, or a nearby wellbore that is ineffectively sealed, could provide subsurface pathways for groundwater pollution from well drilling, flowback or production operations. Pollutants could include:

- turbidity;
- fluids pumped into or flowing from rock formations penetrated by the well; and
- natural gas present in the rock formations penetrated by the well.

These potential impacts are not unique to horizontal wells and are described by the GEIS. The unique aspect of the proposed multi-well development method is that continuous or intermittent activities will occur over a longer period of time at any given well pad. This does not alter the per-well likelihood of impacts from the identified subsurface pathways because existing mitigation measures apply on an individual well basis regardless of how many wells are drilled at the same site. Nevertheless, the potential impacts are acknowledged here and enhanced

[25] This survey did not identify direct regulations for the chemical compounds listed in this table. It is likely that they are indirectly regulated. e.g. Scale inhibitors are composed of several chemical compounds that are likely separately regulated, but the analytical results did not provide the composition of the scale inhibitors. Similarly, specific petroleum hydrocarbons may be regulated, but the analytical results did not provide the composition it tested for.

procedures and mitigation measures are proposed in Chapter 7 because of the concentrated nature of the activity on multi-well pads and the larger fluid volumes and pressures associated with high-volume hydraulic fracturing.

6.1.4.1 Turbidity

The 1992 GEIS stated that "review of Department complaint records revealed that the most commonly validated impact from oil and gas drilling activity on private water supplies was a short-term turbidity problem."[26] This remains the case today. Turbidity, or suspension of solids in the water supply, can result from any aquifer penetration (including water wells, oil and gas wells, mine shafts and construction pilings) if a natural subsurface fracture of sufficient porosity and permeability is present. The majority of these situations correct themselves in a short time.

6.1.4.2 Fluids Pumped Into the Well

ICF International, under its contract with NYSERDA to conduct research in support of the SGEIS preparation, provided the following discussion and analysis with respect to the likelihood of groundwater contamination by fluids pumped into a wellbore for hydraulic fracturing (emphasis added):[27]

> In the 1980s, the American Petroleum Institute (API) analyzed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Although the API did not address the risks for production wells, production wells would be expected to have a lower risk of groundwater contamination due to casing leakage. Unlike Class II injection wells which operate under sustained or frequent positive pressure, a hydraulically fractured production well experiences pressures below the formation pressure except for the short time when fracturing occurs. During production, the wellbore pressure must be less than the formation pressure in order for formation fluids or gas to flow to the well. *Using the API analysis as an upper bound for the risk associated with the injection of hydraulic fracturing fluids, the probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than* 2×10^{-8} *(fewer than 1 in 50 million wells).*

6.1.4.3 Natural Gas Migration

As discussed above, turbidity is typically a short-term problem which corrects itself and the probability of groundwater contamination from fluids pumped into a properly-constructed well is very low. Natural gas migration is a more reasonably anticipated concern with respect to potential

[26] p. FGEIS47

[27] ICF International, Task 1, p. 21

significant adverse impacts. The GEIS in Chapters 9, 10 and 16 describes the following scenarios related to oil and gas well construction where natural gas could migrate into potable groundwater supplies:

- Inadequate depth and integrity of surface casing to isolate potable fresh water supplies from deeper gas-bearing formations;
- Inadequate cement in the annular space around the surface casing, which may be caused by gas channeling or insufficient cement setting time; gas channeling may occur as a result of naturally occurring shallow gas or from installing a long string of surface casing that puts potable water supplies and shallow gas behind the same pipe; and
- Excessive pressure in the annulus between the surface casing and intermediate or production casing. Such pressure could break down the formation at the shoe of the surface casing and result in the potential creation of subsurface pathways outside the surface casing. Excessive pressure could occur if gas infiltrates the annulus because of insufficient production casing cement and the annulus is not vented in accordance with required casing and cementing practices.

As explained in the GEIS, potential migration of natural gas to a water well presents a safety hazard because of its combustible and asphyxiant nature, especially if the natural gas builds up in an enclosed space such as a well shed, house or garage. Well construction practices designed to prevent gas migration would also address other formation fluids such as oil or brine. Although gas migration may not manifest itself until the production phase, its occurrence would result from well construction (i.e., casing and cement) problems.

The GEIS acknowledges that migration of naturally-occurring methane from wetlands, landfills and shallow bedrock can also contaminate water supplies independently or in the absence of any nearby oil and gas activities.

6.1.5 Hydraulic Fracturing Procedure

Concern has been expressed that potential impacts to groundwater from the high-volume hydraulic fracturing procedure itself could result from:

- wellbore failure; or
- movement of unrecovered fracturing fluid out of the target fracture formation through subsurface pathways such as:
    - a nearby poorly constructed or improperly plugged wellbore;

- fractures created by the hydraulic fracturing process;
- natural faults and fractures; and
- movement of fracturing fluids through the interconnected pore spaces in the rocks from the fracture zone to a water well or aquifer.

As summarized in Section 5.18, regulatory officials from 15 states have recently testified that groundwater contamination from the hydraulic fracturing procedure is not known to have occurred despite the procedure's widespread use in many wells over several decades. Nevertheless, NYSERDA contracted ICF International to evaluate factors which affect the likelihood of groundwater contamination from high-volume hydraulic fracturing.[28]

6.1.5.1 Wellbore Failure

As described in Section 6.1.4.2, the probability of fracture fluids reaching an underground source of drinking water (USDW) from properly constructed wells due to subsequent failures in the casing or casing cement due to corrosion is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells).

6.1.5.2 Subsurface Pathways

As explained in Chapter 5 and detailed in Appendix 11, ICF's analysis showed that hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers by movement of fracturing fluids out of the target fracture formation through subsurface pathways when certain natural conditions exist. To guide review and acceptability, these conditions include:

- Maximum depth to the bottom of a potential aquifer ≤ 1,000 feet;
- Minimum depth of the target fracture zone ≥ 2,000 feet;
- Average hydraulic conductivity of intervening strata ≤ 1×10^{-5} cm/sec; and
- Average porosity of intervening strata ≥ 10%.

As noted in Section 2.4.6, a depth of 850 feet to the base of potable water is a commonly used and practical generalization for the maximum depth of potable water in New York. Alpha

---

[28] ICF Task 1

Environmental, under its contract with NYSERDA, provided the following additional information regarding the Marcellus and Utica Shales:[29]

> The Marcellus and Utica shales dip southward from the respective outcrops of each member, and most of the extent of both shales are found at depths greater than 1,000 feet in New York. There are multiple alternating layers of shale, siltstone, limestone, and other sedimentary rocks overlying the Marcellus and Utica shales. Shale is a natural, low permeability barrier to vertical movement of fluids and typically is considered a cap rock in petroleum reservoirs (Selley, 1998) and an aquitard to groundwater aquifers (Freeze & Cherry, 1979). The varying layers of rocks of different physical characteristics provide a barrier to the propagation of induced hydraulic fractures from targeted zones to overlying rock units (Arthur et al, 2008). The vertical separation and low permeability provide a physical barrier between the gas producing zones and overlying aquifers.

6.1.6 Waste Transport

Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and produced brine are classified as non-hazardous industrial waste which must be hauled under a New York State Part 364 waste transporter permit issued by the Department. All Part 364 transporters must identify the general category of wastes transported and provide a signed authorization from each destination facility. However, manifesting is generally not required for non-hazardous industrial waste, which prevents tracking and verification of disposal destination on an individual load basis.

6.1.7 Centralized Flowback Water Surface Impoundments

The potential use of large centralized surface impoundments to hold flowback water as part of dilution and reuse system is described in Section 5.12.2.1.

The Dam Safety Regulations described in Section 5.7.2.1, including the requirement for a Protection of Waters Permit, only apply to fresh water surface impoundments and, therefore, would not apply to flowback water surface impoundments. However, the same concerns exist regarding the potential for personal injury, property damage and natural resource damage if a breach should occur.

Adverse impacts to groundwater quality are also a concern relative to large geomembrane-lined surface impoundments. Controlling leakage is a difficult task. An appreciable hydraulic head

[29] Alpha, p. 3-3

greatly increases the impact of any liner defect. Under such conditions, even the smallest defect can release significant volumes of contaminated liquid over short periods of time.

In addition, in cases where a single-liner system is not ballasted with a protective soil layer and leakage is trapped in the interstitial area between the liner and liner sub-base, the increased hydraulic pressures and buoyant forces of the geomembrane materials may cause the geomembrane to float. This would typically result in more liner system damage. For deep surface impoundments, the amount of ballast material needed to reduce this problem is appreciable and the placement of this large amount of ballast material also increases the amount of liner system defects. Rapid drawdown of the contained liquid can result in instability of the ballast materials on the surface impoundment's side wall, resulting in catastrophic damage of the liner system.

Conveyances to and from centralized impoundments are also potential pathways for contaminants to reach the environment.

6.1.8 Fluid Discharges

Direct discharge of fluids onto the ground or into surface water bodies from the well pad are prohibited. Discharges will be managed at treatment facilities or in disposal wells.

6.1.8.1 Treatment Facilities

Surface water discharges from water treatment facilities are regulated under the Department's SPDES program. Acceptance by a treatment plant of a waste stream that upsets its system or exceeds its capacity may result in a SPDES permit effluent violation or a violation of water quality standards within the receiving water. Water pollution degrades surface waters, potentially making them unsafe for drinking, fishing, swimming, and other activities or unsuitable for their classified best uses.

Treatability of flowback water is a further concern. Residual fracturing chemicals and naturally-occurring constituents from the rock formation could be present in flowback water and have treatment, sludge disposal, and receiving-water impacts. Salts and dissolved solids may not be sufficiently treated by municipal biological treatment and/or other treatment technologies which are not designed to remove pollutants of this nature. Tables 6.1, 6.2 and 6.3 provide information on flowback water composition based on a limited number of samples from Pennsylvania and West Virginia.

6.1.8.1 Disposal Wells

As stated in the GEIS, the primary environmental consideration with respect to disposal wells is the potential for movement of injected fluids into or between potential underground sources of drinking water. The Department is not proposing to alter its 1992 Finding that proposed disposal wells require individual site-specific review. Therefore, the potential for significant adverse environmental impacts from any proposal to inject flowback water from high-volume hydraulic fracturing into a disposal well will be reviewed on a site-specific basis with consideration to local geology (including faults and seismicity), hydrogeology, nearby wellbores or other potential conduits for fluid migration and other pertinent site-specific factors.

6.1.9 Solids Disposal

Most waste generated at a well site is in liquid form. Rock cuttings and the reserve pit liner are the significant exception. The GEIS describes potential adverse impacts to agricultural operations if materials are buried at too shallow a depth or work their way back up to the surface. Concerns unique to Marcellus development and multi-well pad drilling are discussed below.

6.1.9.1 Naturally Occurring Radioactive Material (NORM) Considerations - Cuttings

Based on the analytical results from field-screening and gamma ray spectroscopy performed on samples of Marcellus shale, NORM levels in cuttings are not likely to pose a problem.

6.1.9.2 Cuttings Volume

As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be one-third greater than that for a conventional, vertical well. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time. The geotechnical stability and bearing capacity of buried cuttings, if left in a common pit, may need to be reviewed prior to pit closure.[30]

[30] Alpha, 2009. p. 6-7.

6.1.9.3 Cuttings and Liner Associated With Mud-Drilling

Operators have not proposed on-site burial of mud-drilled cuttings, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater.

6.1.10 Potential Impacts to Subsurface NYC Water Supply Infrastructure

In addition to its surface reservoirs, NYC maintains a system of underground tunnels, aqueducts and other underground infrastructure. Drilling directly into one of these system components could compromise the integrity of the system and provide an opening for non-drilling related contaminants to enter the system. However, damage to the system by high-volume hydraulic fracturing is not reasonably anticipated because the target fracturing zones are thousands of feet deeper than any underground water supply infrastructure.

6.1.11 Degradation of New York City's Drinking Water Supply

A comprehensive, long-range watershed protection and water quality management plan has been established by the City of New York, State of New York, federal government, environmental organizations and upstate watershed communities to protect New York City's critical drinking water supply. Successful implementation of this plan has resulted in cost savings to the City and State of an estimated $8 billion that otherwise would be required to filter this water supply and an additional $300 million yearly expense to operate and maintain a filtration plant. The West of Hudson (WOH) Watershed consists of the Ashokan, Cannonsville, Neversink, Pepacton, Roundout and Schoharie Reservoirs (Figure 2.2).

Degradation of New York City's drinking water supply as a result of surface spills is not a reasonably anticipated impact of the proposed activity. Potential impacts to the NYC Watershed are greatly diminished by a number of reasons related to the inherent nature of the activity. These include the following:

- Setback requirements (i.e., required separation distances) will preclude the possibility of the contents of a ruptured additive container or holding tank pouring directly into a reservoir. It would not be possible for an on-site spill to reach a reservoir without first contacting the ground. Soil adsorption would occur and reduce the potential amount of contaminant reaching the reservoir by flowing across the ground.

- Storage containers for fracturing additives must meet USDOT or UN regulations for their respective chemicals, and controls such as valves and gauges are in place to prevent and minimize spills. It is not reasonable to expect multiple containers at one site or sufficient numbers of containers at separate sites to breach simultaneously and spill their entire contents directly into a reservoir without any detection or attempt at mitigation.

- Hydraulic fracturing is an intensely controlled and monitored activity, with more people present on-site than at any other time during the life of the well. On-site personnel and systems would result in the detection and mitigation of any rupture, equipment failure or any other cause for release.

- Construction and operation of the site in accordance with mitigation measures set forth in Chapter 7, including a required Stormwater Pollution Prevention Plan, would provide spill containment and prevent fluids from running off of the well pad.

- Many chemicals, and chemicals dissolved in water, are subject to evaporation during the warmer months of the year, reducing the volumes or concentrations that would reach reservoirs.

- Complete and instantaneous mixing of contaminants in the reservoirs is not likely to occur because of various characteristics of both the chemicals (density, solubility and dispersion rate) and the reservoirs (areal geometry, wind patterns, tributaries, limnology).

- Natural attenuation processes in soil and water such as biodegradation, volatilization, and chemical or biological stabilization, transformation or destruction may also reduce the concentration of contaminants.

6.2 Floodplains

Flooding is hazardous to life, property and structures. Chapter 2 describes Flood Damage Prevention Laws implemented by local communities to govern development in floodplains and floodways and also provides information about recent flooding events in the Susquehanna and Delaware River Basins. The GEIS summarizes the potential impacts of flood damage relative to mud or reserve pits, brine and oil tanks, other fluid tanks, brush debris, erosion and topsoil, bulk supplies (including additives) and accidents. Severe flooding is described as "one of the few ways" that bulk supplies such as additives "might accidentally enter the environment in large quantities."[31] Local and state permitting processes that govern well development activities in floodplains should consider the volume of fluids and materials associated with high-volume hydraulic fracturing and the longer duration of activity at multi-well sites.

6.X Primary and Principal Aquifers

About one quarter of New Yorkers rely on groundwater as a source of potable water. In order to enhance regulatory protection in areas where groundwater resources are most productive and most

[31] GEIS, p. 8-44

vulnerable, the Department of Health, in 1980, identified eighteen Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the state. These are defined in the Division of Water Technical & Operational Guidance Series (TOGS) 2.1.3 as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems".

Many Principal Aquifers have also been identified and are defined in the DOW TOGS as “highly productive but which are not intensively used as sources of water supply by major municipal systems at the present time”.

Because they are largely contained in unconsolidated materials, the high permeability of Primary and Principal Aquifers and shallow depth to the water table, makes these aquifers particularly susceptible to contamination.

6.3 Freshwater Wetlands

State regulation of wetlands is described in Chapter 2. The GEIS summarizes the potential impacts to wetlands associated with interruption of natural drainage, flooding, erosion and sedimentation, brush disposal, increased access and pit location. Potential impacts to downstream wetlands as a result of surface water withdrawal are discussed in Section 6.1.1.4 of this Supplement. Other concerns described herein relative to stormwater runoff and surface spills and releases, including from centralized flowback water surface impoundments, also extend to wetlands.

6.4 Ecosystems and Wildlife

The GEIS discusses the significant habitats known to exist at the time in or near then-existing oil and gas fields (heronries, deer wintering areas, and uncommon, rare and endangered plants). However, the potential mitigation measures for preventing harm to these habitats would also apply to others, such as the Upper Delaware Important Bird Area. Available site-specific options include required setbacks between the disturbance and a habitat or plant community, relocation of a proposed access road or well pad, replanting of cover vegetation in disturbed areas, complete avoidance of specific habitats or endangered plants and seasonal restrictions on specific operations.

Three areas of concern unique to high-volume hydraulic fracturing are:

1) water withdrawals for hydraulic fracturing;

2) potential transfer of invasive species as a result of activities associated with high-volume hydraulic fracturing; and

3) use of centralized flowback water surface impoundments.

Water withdrawals are addressed above in Section 6.1.1. Invasive species and impoundment use are discussed below.

6.4.1 Invasive Species

An invasive species, as defined by §9-1703 of the Environmental Conservation Law (ECL), is a species that is nonnative to the ecosystem under consideration and whose introduction causes or is likely to cause economic or environmental harm or harm to human health. Invasive species can be plants, animals, and other organisms such as microbes, and can impact both terrestrial and aquatic ecosystems.

While natural means such as water currents, weather patterns and migratory animals can transport invasive species, human actions - both intentional and accidental - are the primary means of invasive species introductions to new ecosystems. Once introduced, invasive species usually spread profusely because they often have no native predators or diseases to limit their reproduction and control their population size. As a result, invasive species out-compete native species that have these controls in place, thus diminishing biological diversity, altering natural community structure and, in some cases, changing ecosystem processes. These environmental impacts can further impose economic impacts as well, particularly in the water supply, agricultural and recreational sectors.[32]

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. Surface water withdrawals also have the potential to transfer invasive aquatic species.

6.4.1.1 Terrestrial

Terrestrial plant species which are widely recognized as invasive[33] or potentially-invasive in New York State, and are therefore of concern, are listed in Table 6.4 below.

[32] ECL §9-1701

[33] As per ECL §9-1703

Table 6.4[34] - Terrestrial Invasive Plant Species In New York State (Interim List) [35]

Terrestrial - Herbaceous	
Common Name	**Scientific Name**
Garlic Mustard	*Alliaria petiolata*
Mugwort	*Artemisia vulgaris*
Brown Knapweed	*Centaurea jacea*
Black Knapweed	*Centaurea nigra*
Spotted Knapweed	*Centaurea stoebe* ssp. *micranthos*
Canada Thistle	*Cirsium arvense*
Bull Thistle	*Cirsium vulgare*
Crown vetch	*Coronilla varia*
Black swallow-wort	*Cynanchum louiseae* (*nigrum*)
European Swallow-wort	*Cynanchum rossicum*
Fuller's Teasel	*Dipsacus fullonum*
Cutleaf Teasel	*Dipsacus laciniatus*
Giant Hogweed	*Heracleum mantegazzianum*
Japanese Stilt Grass	*Microstegium vimineum*
Terrestrial - Vines	
Common Name	**Scientific Name**
Porcelain Berry	*Ampelopsis brevipedunculata*
Oriental Bittersweet	*Celastrus orbiculatus*
Japanese Honeysuckle	*Lonicera japonica*
Mile-a-minute Weed	*Persicaria perfoliata*
Kudzu	*Pueraria montana* var. *lobata*
Terrestrial - Shrubs & Trees	
Common Name	**Scientific Name**
Norway Maple	*Acer platanoides*
Tree of Heaven	*Ailanthus altissima*
Japanese Barberry	*Berberis thunbergii*
Russian Olive	*Elaeagnus angustifolia*
Autumn Olive	*Elaeagnus umbellata*
Glossy Buckthorn	*Frangula alnus*

[34] NYSDEC, DFWMR March 13, 2009 Interim List of Invasive Plant Species in New York State

[35] This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d), but is not the so-called "four-tier lists" referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the "four-tier list" at such time that it becomes available.

Border Privet	*Ligustrum obtusifolium*
Amur Honeysuckle	*Lonicera maackii*
Shrub Honeysuckles	*Lonicera morrowii/tatarica/x bella*
Bradford Pear	*Pyrus calleryana*
Common Buckthorn	*Rhamnus cathartica*
Black Locust	*Robinia pseudoacacia*
Multiflora Rose	*Rosa multiflora*

Operations involving land disturbance such as the construction of well pads, access roads and engineered surface impoundments for both fresh water and flowback fluid storage have the potential to both introduce and transfer invasive species populations. Machinery and equipment used to remove vegetation and soil may come in contact with invasive plant species that exist at the site and may inadvertently transfer those species' seeds, roots, or other viable plant parts via tires, treads/tracks, buckets, etc. to another location on site, to a separate project site, or to any location in between.

The top soil that is stripped from the surface of the site during construction and set aside for re-use during reclamation also presents an opportunity for the establishment of an invasive species population if it is left exposed. Additionally, fill sources (e.g., gravel, crushed stone) brought to the well site for construction purposes also have the potential to act as a pathway for invasive species transfer if the fill source itself contains viable plant parts, seeds, or roots.

6.4.1.2 Aquatic

The presence of non-indigenous aquatic invasive species in New York State waters is recognized, and, therefore, operations associated with the withdrawal, transport, and use of water for horizontal well drilling and high volume hydraulic fracturing operations have the potential to transfer invasive species. Species of concern include, but are not necessarily limited to; zebra mussels, eurasian watermilfoil, alewife, water chestnut, fanwort, curly-leaf pondweed, round goby, white perch, didymo, and the spiny water flea. Other aquatic, wetland and littoral plant species that are of concern due to their status as invasive[36] or potentially-invasive in New York State are listed in Table 6.5.

[36] As per ECL §9-1703

Table 6.5[37] - Aquatic, Wetland & Littoral Invasive Plant Species in New York State (Interim List) [38]

Floating & Submerged Aquatic	
Common Name	**Scientific Name**
Carolina Fanwort	*Cabomba caroliniana*
Rock Snot (diatom)	*Didymosphenia geminata*
Brazilian Elodea	*Egeria densa*
Water thyme	*Hydrilla verticillata*
European Frog's Bit	*Hydrocharis morus-ranae*
Floating Water Primrose	*Ludwigia peploides*
Parrot-feather	*Myriophyllum aquaticum*
Variable Watermilfoil	*Myriophyllum heterophyllum*
Eurasian Watermilfoil	*Myriophyllum spicatum*
Brittle Naiad	*Najas minor*
Starry Stonewort (green alga)	*Nitellopsis obtusa*
Yellow Floating Heart	*Nymphoides peltata*
Water-lettuce	*Pistia stratiotes*
Curly-leaf Pondweed	*Potamogeton crispus*
Water Chestnut	*Trapa natans*
Emergent Wetland & Littoral	
Common Name	**Scientific Name**
Flowering Rush	*Butomus umbellatus*
Japanese Knotweed	*Fallopia japonica*
Giant Knotweed	*Fallopia sachalinensis*
Yellow Iris	*Iris pseudacorus*
Purple Loosestrife	*Lythrum salicaria*
Reed Canarygrass	*Phalaris arundinacea*
Common Reed- nonnative variety	*Phragmites australis* var. *australis*

Invasive species may be transported with the fresh water withdrawn for, but not used for drilling or hydraulic fracturing. Invasive species may potentially be transferred to a new area or watershed if unused water containing such species is later discharged at another location. Other

[37] NYSDEC, DFWMR March 13, 2009 Interim List of Invasive Plant Species In New York State

[38] This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d)), but is not the so-called “four-tier lists” referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the “four-tier list” at such time that it becomes available.

potential mechanisms for the possible transfer of invasive aquatic species may include trucks, hoses, pipelines and other equipment used for water withdrawal and transport.

6.4.2 Centralized Flowback Water Surface Impoundments

Division of Fish, Wildlife and Marine Resources (DFWMR) staff in the Department reviewed Tables 6.2 and 6.3 and concluded that the salt content of the flowback water should discourage most wildlife species from using the surface impoundments. One notable exception is waterfowl. There is a chance that waterfowl might use the impoundments during migration or during winter if water remains unfrozen and if the impoundment is located near feeding areas like corn fields. However, DFWMR staff believe that the flowback water is probably not acutely toxic to waterfowl from short term contact, although adverse effects might result from more prolonged exposure. Vegetation growing immediately around the impoundments, for example in soil used as liner ballast on the inside embankments, could serve as an attractive nuisance and encourage waterfowl to use the impoundments, perhaps as locations to rest during migration. For that reason, the banks of such impoundments should be kept as bare as possible. If waterfowl or other birds are attracted to the ponds despite the salinity and lack of vegetation, then some sort of surface cover, such as netting, "bird balls" or other exclusion measure would have to be considered.

6.5 Air Quality

6.5.1 Regulatory Analysis

Appendices 16 and 17 contain general information on applicability of NOx RACT and proposed revisions of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities. Appendix 18 contains information on the Clean Air Act regulatory definition of "facility" for the oil and gas industry. Specific information regarding emission sources that have potential regulatory implications is presented below.

6.5.1.1 NOx - Internal Combustion Engine Emissions

Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions.

Well Drilling and Hydraulic Fracturing Operations

Oil and gas drilling rigs require substantial power to drill and case wellbores to the depths of hydrocarbon deposits. In the Marcellus Shale, this power will typically be provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale.

The preferred method for calculating engine emissions is to use emission factors provided by the engine manufacturer. If these cannot be obtained, a preliminary emissions estimate can be made using EPA AP-42 emission factors. The most commonly used tables are below.

AP-42 Table 3.2-1: Emission Factors for Uncontrolled Natural Gas-Fired Engines

Pollutant	**2-cycle lean burn**		**4-cycle lean burn**		**4-cycle rich burn**	
	g/Hp-hr (power input)	**lb/MMBtu (fuel input)**	**g/Hp-hr (power input)**	**lb/MMBtu (fuel input)**	**g/Hp-hr (power input)**	**lb/MMBtu (fuel input)**
NO_X	10.9	2.7	11.8	3.2	10.0	2.3
CO	1.5	0.38	1.6	0.42	8.6	1.6
TOC [1]	5.9	1.5	5.0	1.3	1.2	0.27

TOC is total organic compounds (sometimes referred to as THC). To determine VOC emissions calculate TOC emissions and multiply the answer by the VOC weight fraction of the fuel gas.

AP-42 Table 3.3-1: Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines

Pollutant	**Gasoline Fuel**		**Diesel Fuel**	
	g/Hp-hr (power output)	**lb/MMBtu (fuel input)**	**g/Hp-hr (power output)**	**lb/MMBtu (fuel input)**
NO_X	5.0	1.63	14.1	4.41
CO	3.16	0.99	3.03	0.95
TOC				
exhaust	6.8	2.10	1.12	0.35
evaporative	0.30	0.09	0.00	0.00
crankcase	2.2	0.69	0.02	0.01
refueling	0.5	0.15	0.00	0.00

Engine Emissions Example Calculations

A characterization of the significant NOx emission sources during the three operational phases of horizontally drilled, hydraulically fractured natural gas wells is as follows:

1. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Drilling Phase

For a diesel engine drive total of 5400 Hp drilling rig power*, using NOx emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus shale formation, a representative NOx emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NOx emission would be:

NO_X emissions = (6.4 g/Hp-hr) × (5400 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 333.7 TPY

*Engine information provided by Chesapeake Energy

The actual emissions from the engines will likely be much lower than the above PTE estimate, depending on the number of wells drilled at a well site in a given year.

2. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Completion Phase

For diesel-drive 2333 Hp frac pump engine(s)*, using NOx emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus shale formation, a representative NOx emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NOx emission would be:

NO_X emissions = (6.4 g/Hp-hr) × (2333 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 144.1 TPY

*Engine information provided by Chesapeake Energy

The actual emissions from the engines will likely be lower than the above PTE estimate, depending on the number of wells drilled and the number of hydraulic fracturing jobs performed at a well site in a given year.

3. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Production Phase

Using the most recent natural gas compressor station DEC Region 8 permit application information, a NOx emission factor 2.0 g/Hp-hr was chosen as more reasonable (yet still conservative) than AP-42 emission data. The maximum site-rated horsepower is 2500 Hp*. The engine(s) is expected to run year round (8760 hr/yr).

NO_X emissions = (2.0 g/Hp-hr) × (2500 Hp) × (8760 hr/yr) × (ton/2000 lb) ×(1 lb/453.6 g) = 48.3 TPY

*Engine information provided by Chesapeake Energy

The total PTE of the two types of engines exceeds the major source threshold, assuming continuous operation for a full year. However, because the actual emissions are likely to be much lower due to the inherent intermittent nature of these wellsite operations, facilities may want to investigate capping the emissions below the thresholds. This would enable permitting under shorter State facility permitting timeframes. It would also eliminate the applicability of NOx RACT regulations. Since the engines in the example comply with the NOx RACT emission limits, avoiding the rule applicability will avoid cumbersome monitoring requirements that were designed for permanently located engines. In addition to NOx RACT requirements, Title V permitting requirements would also apply to other air pollutants such as carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), ozone (as volatile organic compounds (VOC)), and elemental lead, with the same emission thresholds as for NOx. Review of other emission information for these engines, such as CO and PM emission factor data, reveal an unlikely possibility of reaching major source thresholds triggering Title V permitting requirements for these facilities.

6.5.1.2 Natural Gas Production Facilities NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators)

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. “Lean” TEG contacts the wet gas and absorbs water. The TEG is then considered “rich”. As the rich TEG is passed through a flash separator and/or reboiler for regeneration, steam containing hydrocarbon vapors is released from it. The vapors are then vented from the dehydration unit flash separator and/or reboiler still vent.

Dehydration units with a natural gas throughput below 3 MMscf per day or benzene emissions below 1 tpy are exempted from the control, monitoring and recordkeeping requirements of this subpart. Although the natural gas throughput of some Marcellus horizontal shale wells in New York State could conceivably be above 3 MMscf, preliminary analysis of gas produced at Marcellus horizontal shale gas well sites in states adjacent to New York State indicate a benzene content below the exemption threshold of 1 tpy, for the anticipated range of annual gas production for wells in the Marcellus. However, the affected natural gas production facilities will still likely be required to maintain records of the exemption determination as outlined in 40 CFR 63.774(d) (1) (ii). Sources with throughput of 3 MMscf/day or greater and benzene emissions of 1.0 tpy or greater are subject to emission reduction requirements of the rule. This does not necessarily mean control, depending on the location of the affected emission sources relative to "urbanized areas (UA) plus offset" or to "urban clusters (UC) with a population of 10,000 or greater" as defined in the rule.

6.5.1.3 Flaring Versus Venting of Wellsite Air Emissions

Well completion activities include hydraulic fracturing of the well and a flowback period to clean the well of flowback water and any excess sand (frac proppant) that may return out of the well. Flowback water is routed through separation equipment to separate water, gas, and sand. Initially, only a small amount of gas is vented for a period of time. Once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas to a sales gas line. Recovering the gas to a sales gas line is called a "reduced emissions completion (REC)" or a "green completion."

Normally the flowback gas is flared when there is insufficient pressure to enter a sales line, or if a sales line is not available. There is no current requirement for REC, and the PSC does not now typically authorize construction of sales lines before the first well is drilled on a pad (see Section 5.16.8.1 for a discussion of the PSC role and a presentation of reasons why pre-authorization of gathering lines have been suggested), therefore, estimates of emissions from both flaring and venting of flowback gas are included in the emissions tables in Section 6.5.1.5**.**

Also, during drilling, gaseous zones can sometimes be encountered such that some gas is returned with the drilling fluid, which is referred to as a gas "kick". For safety reasons, the drilling fluid is circulated through a "mud-gas separator" as the gas kick is circulated out of the wellbore. Circulating the kick through the mud-gas separator diverts the gas away from the rig personnel.

Any gas from such a kick is vented to the main vent line or a separate line normally run adjacent to the main vent line.

Drilling in a shale formation does not result in significant gas adsorption into the drilling fluid as the shale has not yet been fractured. Experience in the Marcellus thus far has shown few, if any, encounters with gas kicks during drilling. However, to account for the potential of a gas kick where a "wet" gas from another formation might result in some gas being emitted from the mud-gas separator, an assumed wet-gas composition was used to estimate emissions. For a worst-case scenario, a potential vent rate of 5,000 standard cubic feet (scf) vented in one hour during the drilling phase of a single well is assumed in the analysis.

Gas from the Marcellus Shale in New York is expected to be very "dry", i.e., have little or no VOC content, and "sweet", i.e. have little or no hydrogen sulfide. Except for drilling emissions, two sets of emissions estimates are made to enable comparison of emissions of VOC and HAP from both dry gas production and wet gas production.

6.5.1.4 Number of Wells Per Pad Site

Drilling as many wells as possible from a single well pad provides for substantial environmental benefits from less road construction, surface disturbance, etc. Also, experience shows that average drilling time in days can be improved as more experience is gained in a shale play. However, at present typical drilling rates, it is expected that no more than 10 wells could be drilled, completed, and hooked up to production in any 12-month period. This is because of the interval time periods between drilling, completion, and production such as when the drilling rig must be moved over a distance in order to drill the next well, time to move fracturing equipment on and off the well site, time to hook up and disconnect fracturing equipment, etc. Therefore, the analysis is based on an assumption of 10 wells per site per year.

6.5.1.5 Emissions Tables

Estimated annual emissions from drilling, completion and production activities, based on the placement of a maximum of 10 wells at a wellsite, processing both "dry" and "wet" gas, under both venting and flaring options of well air emissions, are presented in the following tables (based on reference data provided by ALL Consulting, LLC "Horizontally Drilled / High - Volume Hydraulically Fractured Wells Air Emissions Data", dated August 26, 2009):

Table 6.6 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Flaring (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	3.67	5.56
NOx	36.0	14.4	3.77	54.17	12.24	66.41
CO	20.7	6.6	9.20	36.5	61.2	97.7
VOC	1.88	0.6	2.43	4.91	1.76	6.67
SO_2	0.042	0.015	0.066	0.123	0.54	0.663
Total HAP	0.22	0.06	0.029	0.309	0.20	0.509

Table 6.7 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Venting (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	0.0	1.89
NOx	36.0	14.4	3.77	54.17	0.0	54.17
CO	20.7	6.6	9.20	36.5	0.0	36.5
VOC	1.88	0.6	2.43	4.91	1.50	6.41
SO_2	0.042	0.015	0.066	0.123	0.0	0.123
Total HAP	0.22	0.06	0.029	0.309	0.0	0.309

Table 6.8 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Flaring (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	3.67	5.56
NOx	36.0	14.4	3.77	54.17	12.24	66.41
CO	20.7	6.6	9.20	36.5	61.2	97.7
VOC	1.88	0.6	2.43	4.91	64.8	69.71
SO_2	0.042	0.015	0.066	0.123	0.54	0.663
Total HAP	0.22	0.06	0.31	0.59	1.73	2.32

Table 6.9 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Venting (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	0.0	1.89
NOx	36.0	14.4	3.77	54.17	0.0	54.17
CO	20.7	6.6	9.20	36.5	0.0	36.5

VOC	1.88	0.6	2.43	4.91	54.75	59.66
SO_2	0.042	0.015	0.066	0.123	0.0	0.123
Total HAP	0.22	0.06	0.31	0.59	0.0037	0.594

6.5.1.6 Offsite Gas Gathering Station Engine

For gas gathering compression, it is anticipated that most operators will select a large 4-stroke lean-burn engine because of its fuel efficiency. A typical compressor engine is the 1,775-hp Caterpillar G3606, which is the engine model used for the analysis.

A proposed amendment to NESHAP Subpart ZZZZ will place very strict limits on formaldehyde emissions from reciprocating internal combustion engines. In the near future, 4-stroke lean-burn engines will likely be required to have an oxidation catalyst that will reduce formaldehyde emissions by approximately 90%.

The annual emissions data for a typical gas gathering compressor engine is given in Table 6.21 below (based on reference data provided by ALL Consulting, LLC "Horizontally Drilled/High - Volume Hydraulically Fractured Wells Air Emissions Data", dated August 26, 2009):

Table 6.10 - Estimated Off-Site Compressor Station Emissions (Tons/Year)

Component	Uncontrolled 4-Stroke Lean Burn Engine
PM	0.514
NOx	33.29
CO	65.7
SO_2	0.0
Total VOC	16.64
Total HAP	2.74

6.5.1.7 Natural Gas Condensate Tanks

Fluids that are brought to the surface during production at natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids (known as condensate). Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. Hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. Initial analysis of natural gas produced at Marcellus shale horizontal gas well sites in states adjacent to New York State indicates insufficient BTEX and other liquid hydrocarbon content to justify installation of collection and storage equipment for natural gas liquids.

6.5.1.8 Potential Emission of Fracturing Water Additives from Surface Impoundments

Fracturing fluid currently being utilized in the Marcellus Shale is comprised mainly of water with sand, polymers and various chemical additives. When the fluid is flowed back out of the well, it is typically stored in tanks or lined pits until it can be trucked to a waste water treatment facility or other disposal facility; storage in tanks minimizes atmospheric contamination from the additives in the flowback.

However, recent industry responses indicate that fluid from multiple well sites may be accumulated for longer term storage at a centralized impoundment designed for the storage of flowback fluid. While the actual concentrations of the additives of concern in the centralized impoundments may be small, it is premature to assume that the contribution of these additives to air emissions is negligible.

Given that NYS Marcellus Shale is in the early stages of development, common practices for water handling have not been developed, but a worst case scenario can be developed from available information and surveys of what NYS Marcellus Shale operators plan to implement. One operator reports that water used for hydraulic fracturing of wells in the NYS Marcellus Shale is usually trucked to the site. It is estimated that over 800,000 gallons of water are needed per hydraulic fracturing stage. Because of the long length of each horizontal well, several fracturing stages are required per well. An entire hydraulic fracturing job may use as much as 5,000,000 gallons of water. In general, water can be stored in tanks, a lined pit, or in centralized impoundments servicing multiple pads. Water can be stored in large, portable water tanks at the well site, and then pumped from the water tanks down-hole, with one Marcellus Shale operator reporting using frac tanks to capture the flowback water and produced water from the formation. A lined pit is also an option for capturing flowback water, and operators report plans to construct lined pits at the wellsite for temporary storage of flowback water.

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

EPA stated in its original rulemaking documents for 40 CFR 63 Subpart HH (63 FR 6388, February 6, 1998), that surface impoundments and wastewater operations, among other sources, were considered for potential regulation, but were exempted. However, air quality modeling analysis performed to assess the potential air impacts of unconventional natural gas production operations in the Marcellus Shale in support of the SGEIS identified methanol emissions from centralized flowback water surface impoundments as a pollutant of concern. Thus, this identified emission could be subject to environmental impact assessment and mitigation as prescribed by 6 NYCRR Part 617 State Environmental Quality Review (SEQR).

6.5.2 Air Quality Impact Assessment

6.5.2.1 Introduction

As part of the Department's effort to address the potential air quality impacts of horizontal drilling and hydraulic fracturing activities in the Marcellus Shale and other gas low permeability reservoirs, an air quality modeling analysis was undertaken. The assessment was carried out to determine whether the various expected operations at a "typical" multi-well site would have the potential for any adverse air quality impacts. A number of issues raised by public comments during the SGEIS scoping process were also addressed by subsequently developing information on operational scenarios specific to multi-well horizontal drilling and hydraulic fracturing, which allowed DEC's Division of Air Resources (DAR) to conduct the modeling assessment, and to determine possible air permitting requirements. This section presents the air quality analysis undertaken by DAR staff based on operational and emissions information supplied mainly by industry and its consultant in a submission hereafter referred to as the "industry report"[39]. To a limited extent, certain supplemental information from ICF International's report to NYSERDA[40] was also used. The applicability determinations of DEC air permitting regulations and the verification approach to the emission calculations are contained in Section 6.5.2.

To the extent that the information being used was for the modeling of a generic multi-well site and its operations, it was necessary to reconcile and define a "worst case" scenario for the various activities in terms of expected impacts. Certain assumptions were made on the type and sizes of equipment to be used, the potential for simultaneous operation of the equipment on a short-term basis (i.e. hourly and daily), and the duration of these activities over a period of a year in order to be able to compare impacts to the corresponding ambient thresholds. For other air emissions related specifically to impoundments containing the flowback of various additives to the hydraulic fracturing water, neither industry nor the ICF report contained the necessary emission rate data. However, chemical composition information on the additives used in hydraulic fracturing water was made available to DEC by well-service and chemical supply companies which was used by DAR to develop the necessary emission rates, with a request to industry for "verification" of intermediate data needed for these calculations.

The air quality analysis relied upon recommended EPA and DEC air dispersion modeling procedures to determine "worst case" impacts of the various operations and activities identified for the horizontal multi-well sites. Dispersion modeling is an acceptable tool, and at times the only option, to determine the impacts of many source types in permitting activities and environmental impact statements. Where necessary, the analysis approach relied on assumed worst case emissions and operations scenarios due to not only the nature of this generic assessment, but also because detailed model input data for the sources and their relative locations on a typical well pad cannot be simply identified or analyzed. Modeling was performed for various criteria pollutants (those with National Ambient Air Quality Standards, NAAQS) and a set of non-criteria pollutants (including toxics) for which New York has established a standard or other ambient threshold levels. Some of these toxic pollutants were identified in public comments

[39] ALL Consulting, 2009.

[40] ICF, 2009.

during the SGEIS scoping process and were quantified to the extent possible for both the modeling and applicability determinations.

The following sections describe the basic source categories and operations at a typical multi-well site with hydraulic fracturing, the modeling procedures and necessary input data, the resultant impacts, and a set of conclusions drawn from these results. These conclusions are meant to guide the set of conditions under which a site specific assessment might or might not be necessary. These conditions are summarized in Chapter 3.

6.5.2.2 Sources of Air Emissions and Operational Scenarios.

In order to properly estimate the air quality impacts of the set of sources at a single pad with multiple horizontal wells, the operating scenarios and associated air emission sources must be correctly represented. Since these operations have a number of interdependent as well as independent components, the Department has defined both the short-term and long term emission scenarios from the various source types in order to predict conservative, yet realistic impacts. The information used to determine the emission sources and their operating scenarios and constraints, as well as the associated emission rates and parameters, were provided by the industry report, while certain operational scenario restrictions were presented in the ICF report, which reflects information obtained from industry with drilling activities in other states. Where necessary, further data supplied by industry or determined appropriate by DMN was used to fill in data gaps or to make assumptions. In some of these instances, the lack of specific information necessitated a worst-case assumption be made for the purposes of the modeling exercise. Examples of the latter include defining “ambient air” based on the proximity of public access to the centralized impoundment and the likely structure dimensions to calculate their influence on the stack plumes.

The industry and ICF reports indicate three distinct operation stages and four distinct source types of air emissions for developing a representative horizontally-drilled multi-well pad. The phases are drilling, completion, and gas production, each of which has either similar or distinct sources of air emissions. These phases and the potential air pollution sources are presented in the industry report, section 2.1.5 and Exhibit 2.2.1 of the ICF report, and in Chapter 5 of the SGEIS, and will only be briefly noted herein. Of the various potential sources of air emissions, a number have distinct quantifiable and continuous emissions which lend themselves to modeling. On the other hand, the ICF report also identifies other generic sources of minor fugitive emissions (e.g. mud return lines) or of emergency release type (e.g. BOP stack), or of a pollutant which is quantified only as of “generic” nature (total VOCs for tanks) which cannot be modeled within the current scope of analysis. However, in instances where speciated VOCs or Hazardous Air Pollutants (HAPs) are provided, such as for the glycol dehydrator and flowback venting of gas, the modeling was used to predict impacts which were then compared to available ambient thresholds.

The total operations associated with well drilling can be assigned to four “types” of potential sources: 1) combustion from engines, compressors, line heaters and flares; 2) short-term venting of gas constituents which are not flared, 3) chemicals in the additives used for hydraulic fracturing and which remain in the flowback water to be potentially deposited in onsite or off site impoundments; and 4) emissions from truck activities. Each of these source categories have limitations in terms of the size and number of the needed equipment, their possible simultaneous operations over a short-term period (e.g. 24 hour), and the time frames over which these equipment or activities could occur over a period of one year, which effects the corresponding annual impacts. Some of these limitations are described in the industry report. These limitations and further assumptions were taken into account in the modeling analysis, as further discussed in Section 6.5.2.3.

Many of the sources for which the industry report tabulates the drilling, completion and production activities are depicted in the typical site layout represented schematically in Exhibit 2.1.3 of the ICF report. The single pad for multi-horizontal wells is confined to an area of about 150 meters (m) by 150 meters as a worst case size of the operations. From this single pad, wells are drilled in horizontal direction to develop an area of about one square mile. The industry report notes the possibility of up to ten horizontal wells being eventually drilled and completed per pad over a year’s time, while the ICF report notes that simultaneous drilling and completion on the same pad will be limited to a single operation for each. This limitation was determined appropriate by DMN for analysis of short-term impacts. Thus, the simultaneous operations on a pad for the assessment of impacts of 24 hours or less is limited to the equipment necessary to drill one well and complete another. In addition, according to DMN, there is a potential that a third well’s emissions could be flared at the same time as these latter operations. Thus, this source was also included in the simultaneous operation scenario for criteria pollutants. It should be noted that no emissions of criteria pollutants resulting from uncontrolled venting of the gas are expected. The other sources which could emit criteria pollutants are associated with the production phase operations; that is, the off-site compressors and line heaters could be operating simultaneously with the single pad drilling, completion and flaring operations. The industry report provides data for a possible "on-site" line heater instead of at the compressor station and this source was placed on the pad area and provides for a more conservative impact.

The industry report also provides emission data for the non-criteria pollutants as species of VOCs or HAPs associated with both combustion and gas venting. Review of this information indicates two essentially different sets of sources which can be treated independently in the modeling analysis. The first set is the gas venting sources: the mud-gas separator, the flowback gas venting, and the glycol dehydrator. These sources emit a distinct set of pollutants associated with the "wet" gas scenario, defined in the industry report as containing "heavier" hydrocarbons such as benzene. The industry and ICF reports note that gas samples in the Marcellus Shale have not detected these heavier species of VOC, nor hydrogen sulfide (H_2S). However, the industry report also notes the possibility of gas pockets with "wet" gas and provides associated emissions. To be comprehensive, the modeling analysis has calculated the impacts of these species which could be realized in the westernmost part of New York according to DMN.

The industry report also notes that gas venting is a relatively short-term phenomenon, especially during the flowback period where the vented gas is preferentially flared after a few hours of venting. Since there are essentially no simultaneous short-term emissions expected of the same pollutants at the pad other than the venting, coupled with the clear dominance of the flowback venting emissions of these pollutants, the modeling was simplified for this scenario and only the short-term impacts were determined, as described in more detail in Section 6.5.1.3. The second set of non-criteria pollutant emissions presented in the industry report is associated mainly with combustion sources. These non-criteria pollutants could be emitted over much longer time periods, considering these sources are operated over these longer periods, both per-well drilling activity and potential multi-well operations over a given year. Thus, for these pollutants, both short-term and annual impacts were calculated. It should be noted that, since the glycol dehydrator could operate for a full year also, its emissions of the same pollutants as those due to combustion were also included in this assessment of both short-term and annual toxic impacts. Furthermore, the flare emissions are included in the combustion scenario (and not in the venting), as the flaring of flowback gas results in over 95% destruction of these pollutants.

In addition, due to the conversion of H_2S to SO_2 during flaring, the flare was included in the criteria pollutant simultaneous operations scenario modeling. Table 6.11 summarizes the set of sources and the pollutants which have been modeled for the various simultaneous operations for short-term impacts. The specific modeling configuration and emissions data of the various sources are discussed in Section 6.5.2.3.

On the other hand, the emissions of the chemicals associated with the additive compounds used in the hydraulic fracturing operations during the completion phase and which might be deposited in the flowback water impoundments, are modeled distinctly from the other sources. This is because none in the set of chemicals chosen for the Department's modeling exercise are in common with the pollutants modeled for other operations. It should be noted that both the ICF report and certain industry operators took the position that there are essentially negligible emissions of these chemicals into the air and, thus, no mitigation measures are necessary. It is prudent to quantify these emissions and explicitly determine the consequent impacts. Thus, the Department has performed an assessment of a set of representative chemicals in the additives. Details of how this set was chosen and emissions calculated are presented in Section 6.5.2.3. The ICF report presents the size of an onsite impoundment as about 15m by 45m and also noted the possibility of a larger centralized impoundment with a size of 150m by 150m. Both of these scenarios have been modeled.

Many of the pollutants have annual ambient standards and thresholds and, thus, the modeling of the corresponding annual impacts should account for the long-term emission rates. It is common practice in modeling guideline requirements to conservatively use the maximum short-term emission rates for a full year of operations in instances where there are no long term restrictions on operations or when industry does not provide such verifiable limitations on its emissions. For some of the operations during Marcellus Shale drilling, these annual emissions will likely be much lower even if up to 10 wells are drilled at a pad in a year. The industry report discusses some of these operational restrictions and presents data for "average" conditions expected during all phases of operations. These average emissions are calculated for the specific time frames of a certain operation related to drilling and completion of one well; in addition to these average emissions, the report provided the maximum days of such operations. For example, the average emissions for the engines used for hydraulic fracturing are noted to be lower than the corresponding maximum short-term emissions due to the various "stages" of that operation. In addition, however, the whole fracturing operation of a single well takes only 2 to 3 days, which must be taken into account if the annual emissions are to be properly calculated. Another example is the flaring operation. Although the emissions from the flare are the same in the average and maximum tables, this operation is of a very limited nature. The industry report notes 3 days as the period of actual flaring prior to the production phase.

Since each pad could potentially have up to ten wells drilled over a year, it is also necessary to incorporate these limitations in the potential annual emissions in order not to predict unrealistically high annual impacts. These considerations are addressed further in the emission data discussions and in the resultant impact sections. On the other hand, the production phase operations are expected to occur over a full year and are, thus, conservatively modeled at the maximum short-term emission rates, as required by EPA and DEC modeling guidelines.

For the annual impacts from the impoundment emissions, a set of considerations and assumptions was made. Current regulations on well drilling require the removal of the flowback water from on site operations within 45 days of end of completion. However, for multi-well drilling operations, industry information submitted previously had indicated that this time-frame would be impractical from a few standpoints, including the fact that up to half of the maximum number of wells per pad could be drilled and completed on a "continuous" basis, while the rest could be done at a later time. The industry report notes the possibility of drilling up to ten wells in a year at a pad. This implies that additives could be "replenished" into the impoundment for a considerable amount of time over a year. In addition, certain industry operators indicated a desire to have a larger centralized impoundment which could serve multiple pads over a two mile square area. This means that flowback water from up to 4 pads could potentially be put into this impoundment, and the emissions from this centralized impoundment could easily be considered "quasi-continuous" over a year. Industry has also indicated a desire to keep at least the offsite impoundments open for up to three years. Thus, the modeling for annual impacts from impoundments was initially performed assuming year long "emissions" at the maximum calculated levels, and the resultant concentrations were compared to the corresponding annual thresholds to determine the consequences of this scenario.

The last type of emission source associated with the multi-well operations is truck traffic. An estimate of the number of trucks needed for the various activities at a single well pad, including movement of ancillary equipment, delivery of fresh water and proppant/additives, and the hauling of flowback is presented in Section 6.11. It should be first noted that direct emissions from mobile sources are controlled under Title II of the Clean Air Act (CAA) and are specifically exempt from permitting activities. Thus, these emissions are also not addressed in a modeling analysis, with two exceptions. At times, the indirect emissions of fugitive particulate matter are modeled when estimates of emissions are large. The latter occurs mainly due to poor dust control measures and the best approach to mitigate these emissions is to have a dust control plan. In addition, emissions of PM2.5 from mobile sources associated with a project and which occur on-site are to be addressed by DEC's Commissioner's Policy CP-3341. Again, if these emissions are large enough, a modeling analysis is performed for an EIS. The emission calculations are not to include those associated with incidental roadway traffic away from the onsite operations.

Emissions of both PM10 and PM2.5 due to truck operations were provided by DAR's Mobile Source Panning staff based on the movement of total number of trucks on-site for the drilling of one well. These emissions were then multiplied by the 10 potential wells which might be drilled over a year, and resulted in relatively minor quantities of 0.2 tpy maximum PM2.5 emissions. This is consistent with the limited number and limited use of trucks at the well pad. These emissions are well below the CP-33 threshold of 15tpy. Thus, no modeling was performed for these pollutants and any necessary mitigation scheme for these would be the application of an appropriate dust control methods and similar limitations on truck usage, such as inordinate idling.

6.5.2.3 Modeling Procedures

EPA and DEC guidelines[42] on air dispersion modeling recommend a set of models and associated procedures for assessing impacts for a given application. For stationary sources with "non-reactive" pollutants and near-field impacts, the refined AERMOD model (latest version, 07026) and its meteorological and terrain preprocessors is best suited to simulate the impacts of the sources and pollutants identified in the Marcellus Shale and other gas reservoir operations. This model is capable of providing impacts for various averaging times using point, volume or area source characteristics, using hourly meteorological data and a set of receptor locations in the surrounding area as inputs. The model simulates the impact of "inert" pollutants such as SO_2, NO_2, CO, and particulates without taking into account any removal or chemical conversions in

---

[41] *Assessing and Mitigating Impacts of Fine Particulate Matter Emissions.* See: http://www.dec.ny.gov/chemical/8912.html

[42] USEPA *Guideline on Air Dispersion Models*, Appendix W of 40 CFR, Part 51 andDEC's program policy guide DAR10: *NYSDEC Guidelines on Dispersion Modeling Proceduresfor Air Quality Impact Analysis*. See http://www.dec.ny.gov/chemical/8923.html.

air, which provides for conservative ambient impacts. However, these effects are of minor consequences within the context of plume travel time and downwind distances associated with the maximum ambient impact of pollutants discussed in this section.

AERMOD also does not treat secondary formation of pollutants such as Ozone (O_3) from NO_2 and Volatile Organic Compounds (VOCs), but it can model the non-criteria and toxic pollutant components of gas or VOC emissions in relation to established ambient thresholds. There does not exist a recommended EPA or DEC "single" source modeling scheme to simulate O_3 formation from its precursors. This would involve not only complex chemical reactions in the plumes, but also the interaction of the regional mix of sources and background levels. Such an assessment is limited to regional scale emissions and modeling and is outside the scope of the analysis undertaken herein.

Thus, the AERMOD model was used with a set of emission rates and source parameters, in conjunction with other model input data discussed in the following subsections, to estimate maximum ambient impacts, which are then compared to established Federal and New York State ambient air quality standards (AAQS) and other ambient thresholds. The latter are essentially levels established by DEC's Division of Air Resources (DAR)'s program policy document DAR-143. These levels are the 1 hour SGCs and annual AGCs (short-term and annual guideline concentration, respectively). Where certain data on the chemicals modeled and the corresponding ambient thresholds were missing, New York State Department of Health (DOH) staff provided the requested information. For the thresholds, DEC's Toxics Assessment section then calculated the applicable SGCs and AGCs. The modeling procedures also invoke a number of "default" settings recommended in the AERMOD user's guide and EPA's AERMOD Implementation Guide. For example, the settings of potential wells are not expected to be in "urban" locations, as defined for modeling purposes and, thus, the rural option was used. Other model input data are described next.

Meteorological Data

The AERMOD model requires the use of representative hourly meteorological data, which includes parameters such as wind speed, wind direction, temperature and cloud cover for the calculation of transport and dispersion of the plumes. A complete set of all the parameters needed

[43] See: http://www.dec.ny.gov/chemical/30560.html

for modeling is generally only available from National Weather Service (NWS) sites. The "raw" data from NWS sites are first pre-processed by the AERMET program and the AERSURFACE software using land use data at the NWS sites, which then create the necessary parameters to be input to AERMOD. There is a discrete set of NWS sites in New York which serves as a source of representative meteorological data sites for a given project. However, for this analysis, the large spatial extent of the Marcellus Shale necessitated the use of a number of the NWS site data in order to cover the meteorological conditions associated with possible well drilling sites throughout the State.

Figure 6.4 presents the spatial extent of the Marcellus Shale and the six NWS sites chosen within this area and deemed adequate for representing meteorological conditions for the purpose of dispersion modeling of potential well sites. It was judged that these sites will adequately envelope the set of conditions which would result in the maximum impacts from the relatively low level or ground level sources identified as sources of air pollutants. In addition, EPA and DEC modeling guidance recommends the use of five years of meteorological data from a site in order to account for year to year variability. For the current analysis, however, the Department has chosen two years of data per site to gauge the sensitivity of the maxima to these data and to limit the number of model calculations to a manageable set. It was determined that impacts from the relatively low level sources would be well represented by the total of 12 years of data used in the analysis.

The NWS sites and the two years of surface meteorological data which were readily available from each site are presented in Table 6.12, along with latitude and longitude coordinates. In addition to these surface sites, upper air data is required as input to the AERMOD model in order to estimate certain meteorological parameters. Upper air data is only available at Buffalo and Albany for the sites chosen for this analysis, and were included in the data base. It should be noted that upper air data is not the driving force relative to the surface data in modeling low level source impacts within close proximity of the sources, as analyzed in this exercise. The meteorological data for each year was used to calculate the maximum impacts per year of data and then the overall maxima were identified from these per the regulatory definitions of the specific AAQS and SGCs/AGCs, as detailed in the subsequent subsection.

Receptor and Terrain Input Data

Ground level impacts are calculated by AERMOD at user defined receptor locations in the area surrounding the source. These receptors are confined to "ambient air" locations to which the public has access. Current DMN regulations define a set of "set back" distances from the well sites to roadways and residences. However, these set back distances (e.g. 25m) are defined from the wellhead for smaller "footprint" vertical wells relative to the size of the multi-pad horizontal wells. Furthermore, EPA's strict definition of ambient air only excludes areas to which the public is explicitly excluded by enforceable measures such as fences, which might not be normally used by the industry. Thus, in order to determine the potential closest location of receptors to the well site, the modeling has considered receptors at distances as close as the boundary of a 150m by150m well pad. On the other hand, it is clear from diagrams and pictures of sample sites that the public would have no access to within the well pad area. However, the closest receptor to any of the sources was limited to 10 m to allow for a minimum practical "buffer" zone between the equipment on the pad and its edge. The "centralized" impoundment in which the flowback water is to be placed has not been identified with a "set back" distance, except industry has noted that a fence would be erected around the pond. Thus, the closest receptors for this source were placed at 10 meters from the impoundment's edge which is the closest practical distance at which a fence would need to be placed.

The location of the set of modeled receptors is an iterative process for each application in that an initial set is used to identify the distance to the maximum and other relatively high impacts, and then the grid spacing may need to be refined to assure that the overall maxima are properly identified. For the type of low level and ground level sources which dominate the modeled set in this analysis, it is clear that maximum impacts will occur in close proximity to the sources. Thus, a dense grid of 5m and 10 m spacing was placed along the onsite and offsite impoundment "fences", respectively, and extended on a Cartesian grid at 10m grid spacing out to 100m from the sources in all directions. In a few cases, the modeling grid was extended to a distance of 1000m at a grid spacing of 25m from the 100m grid's edge in order to determine the concentration gradients. For the combustion and venting sources, an initial grid at 10 m increment was placed from the edge of the 150m by 150m pad area out to 1000m, but this grid was reduced to a Cartesian grid of 20m from spacing the "fenceline" to 500m in order to reduce computation time. The revised receptor grid resolution was found to adequately resolve the maxima as well for the purpose of demonstrating the anticipated drop off of concentrations beyond these maxima.

The AERMOD model is also capable of accounting for ground level terrain variations in the area of the source by using U.S. Geological Survey Digital Elevation Model (DEM) or more recent

National Elevation Data (NED) sets. However, for sources with low emission release heights, the current modeling exercise was performed assuming a horizontally invariant plane (flat terrain) as a better representation of the impacts for two reasons. First, given the large variety of terrain configurations where wells may be drilled, it was impractical to include a “worst case” or “typical” configuration. More importantly, the maximum impacts from the low level sources are expected to occur close-in to the facility site, and any variations in topography in that area was determined to be best simulated by AERMOD using the concept of “terrain following” plumes.

It should be clarified that this discussion of terrain data use in AERMOD is distinct from the issue of whether a site might be located in a complex terrain setting which might create distinct flow patterns due to terrain channeling or similar conditions. These latter mainly influence the location and magnitude of the longer term impacts and are addressed in this analysis to the extent that the set of meteorological data from six sites included these effects to a large extent. In addition, the air emission scenarios addressed in the modeling for the three operational phases and associated activities are deemed to be more constrained by short-term impacts due to the nature and duration of these operations, as discussed further below. For example, the emissions from any venting or well fracturing are intermittent and are limited to a few hours and days before gas production is initiated.

Emissions Input Data

EPA and DEC guidance require that modeling of short-term and annual impacts be based on corresponding maximum potential and, when available, annual emissions, respectively. However, guidance also requires that certain conservative assumptions be made to assure the identification of maximum expected impacts. For example, the short-term emission rates have to represent the maximum allowable or potential emissions which could be associated with the operations during any given set of hours of the meteorological data set and the corresponding averaging times of the standards. This is to assure that conditions conducive to maximum impacts are properly accounted for in the varying meteorological conditions and complex dependence of the source’s plume dispersion on the latter. Thus, for modeling of all short-term impacts (up to 24 hours), the maximum hourly emission rate is used to assure that the meteorological data hours which determination the maximum impacts over a given period of averaging time were properly assessed.

Based on the information and determinations presented in Section 6.5.1.2 on the set of sources and pollutants which need to be modeled, the necessary model input data was generated. This data includes the maximum and annual emission rates for the associated stack parameters for all of the pollutants for each of the activities. In response to the Department's request, industry provided the necessary model input data for all of the activities at the multi-well pad site, as well as at a potential offsite compressor. These data were independently checked and verified by DAR staff and the final set of source data information was supplied in the industry report noted previously. Although limited source data were also contained in the ICF report, the data provided by industry were deemed more complete and could be substantiated for use in the modeling.

The sources of emissions specific to Marcellus shale operations are treated by AERMOD as either point or area sources. Point sources are those with distinct stacks which can also have a plume rise, simulated by the model using the stack temperatures and velocities. An example of a point source is the flare used for the temporary vented gas. Area sources are generally low or ground level sources of distinct spatial dimensions which emit pollutants relatively uniformly over the whole of the area. The flowback water impoundments are a good example of area sources. In addition to the emission rates and parameters supplied by industry, available photographs and diagrams indicated that many of the stacks could experience building downwash effects due to the low stack heights relative to the adjacent structure heights. In these instances, downwash effects were included in a simplified scheme in the AERMOD modeling by using the height and "projected width" of the structure. These effects were modeled to assure worst case impacts for the compressors and engines were properly identified. The specific model input data used is described next, with criteria and non-criteria source configurations presented separately for convenience.

Criteria Pollutant Sources - The emission parameters and rates for the combustion source category at a multi-horizontal well pad were taken from data tables provided in the industry report. In some instances, additional information was gathered and assumptions made for the modeling. The report provides "average" and maximum hourly emission rates, respectively, of the criteria pollutants in Tables 7 and 8 for the drilling operations, Tables 14, 15, 20 and 21 for the completion phase operations, Table 18 for the production phase sources, and Table 24 for the offsite compressor. It should be noted that the criteria pollutant source emissions in these tables are not affected by the dry versus wet gas discussions, with the exception of SO_2 emissions from flaring of H_2S in wet gas. For this particular pollutant, the flare emission rate from Table 21 was used. Furthermore, the modeling has included the off-site compressor in lieu of the smaller onsite compressor at the wellhead and an onsite line heater instead of an offsite one in order to determine expected worst case operations impacts.

As discussed previously, initial modeling of both short-term and annual impacts were based on the maximum hourly emissions rates, with further analysis of annual impacts performed using more representative long term emissions only when necessary to demonstrate compliance with corresponding annual ambient thresholds. For the short-term impacts (less than 24 hour), it was assumed that there could be simultaneous operations of the set of equipment at an on-site pad area for one well drilling, one well completion, and one well flaring, along with operations of the onsite line heater and off site compressor for the gas production phase for previous completed wells. It should be clarified that although AERMOD currently does not include the flare source option in the SCREEN3 model, the heat release rate provided in Table 15 of the industry report was used to calculate the minimum flare "flame height" as the stack height for input to AERMOD.

The placement of the various pieces of equipment in Table 6.11 on a well pad site was chosen such as not to underestimate maximum offsite as well as combined impacts. For example, the schematic diagram in the ICF report represents a typical set up of the various equipment, but for the modeling of the sources which could be configured in a variety of ways on a given pad, the locations of the specific equipment were configured on a well pad without limiting their potential location being close to the property edge. That is, receptors were placed at distances from the sources as if these were near the edge of the property, with the "buffer zone" restriction noted previously. This was necessary since many of these low level sources could have maximum impacts within the potential 150m distance to the facility property and receptors could not be eliminated in this area.

At the same time, however, it would be unrealistic to locate all of the equipment or a set of the same multi-set equipment at an identical location. That is, certain sources such as the flare are not expected to be located next to the rig and the associated engines due to safety reasons. In addition, there are limits to the size of the "portable" engines which are truck-mounted, thus requiring a set of up to 15 engines placed adjacent to each other rather than treating these as a single emission point. Since there were some variations in the number and type of the multi-source engines and compressors specifically used for drilling and completion, a balance was reached between using a single representative source, with the corresponding stack parameters and total emissions, versus using distinct individual source in the multi set. This determination was also dictated by the relative emissions of each source.

The modeling used a single source representation for the drilling engines and compressors from Table 8, while for the fracturing pump engines, five sources were placed next to each other to represent three-each of the potential fifteen noted in Table 15 of the industry report. The total emission rates for the latter sources were divided over the five representative sources in proper quantities. The rest of the sources are expected to either be a single equipment or are in sets such that representation as a single source was deemed adequate. Using sample photographs from existing operations in other states, estimates of both the location as well as the separation between sources were determined. For example, the size of the trucks with mounted frack engines was used to determine the separation between a row of the five representative sources. These photographs were also used to estimate the dimension of the "structures" which could influence the stack plumes by building downwash effects. All of the sources were deemed to have a potential for downwash effects, except for the flare/vent stack. The height and "effective" horizontal width of the structure associated with each piece of equipment were used in the modeling for downwash calculations.

It was also noted from the photographs that two distinct types of compressors are used for the drilling operations, with one of the types having "rain-capped" stacks. This configuration could further retard the momentum plume rise out of the stack. Thus, for conservatism, this particular source was modeled using the "capped" stack option in AERMOD with the recommended low value for exit velocity. Furthermore, since the off-site "centralized" compressor could conceivably be located adjacent to one of the multi-well pads, this source was located adjacent to, but on the other side of the edge of the 150m by 150m pad site.

The placement of the various sources of criteria pollutants in the modeling is represented in Figure 6.5. This configuration was deemed adequate for the determination of expected worst case impacts from a 'typical" multi-well pad site. Although the figure outlines the boundary of the 150m by 150m typical well pad area, it is again clarified that receptors were placed such that each source would have close-in receptors beyond the 10 m "buffer" distance determined necessary from a practical standpoint. That is, receptors were placed in the pad area to assure simulation of any configuration of these sources on the pad at a given site.

Annual impacts were initially calculated using the maximum hourly emission rates, and the results reviewed to determine if any thresholds were exceeded. If impacts exceeded the annual threshold for a given pollutant, the “average” emission rates specifically for the drilling engines/compressors in Table 7 and for the hydraulic fracturing and flaring operations from Table 20 of the industry report were used. For the other sources, such as the line-heater and offsite compressor, the average and maximum rates are the same as presented in Tables 18 and 24, respectively, and were not modified for the refined annual impacts. As these average rates account only for the variability of “source demand” for the specific duration of the individual operations, an additional adjustment needed to be made for the number of days in a year during which up to 10 such well operations would occur. Thus, from Tables 7 and 14, it is seen that there would be a maximum of 250 days of operations for the drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year. Thus, for these sources, the annual average rate was adjusted accordingly. On the other hand, there are no such restrictions on the use of the line heater and off-site compressor for the production phase and the annual emissions were represented by the maximum rates. Some of these considerations are further discussed in the resultant impact section.

Lastly, in order to account for the possibility of well operations at nearby pads at the same time as operations at the modeled well pad configuration, a sensitivity analysis was performed to determine the potential contribution of an adjacent pad to the modeled impacts. This assessment addressed, in a simplified manner, the issue of the potential for cumulative effects from a nearby pad on the total concentrations of the modeled pad such that larger “background levels” for the determination of compliance with ambient threshold needed to be determined. The nearby pad with identical equipment and emissions as the pad modeled was located at a distance of one kilometer (km) from the 150m by 150m area of the modeled pad. This separation distance is the minimum expected for horizontal wells drilled from a single pad, which extends out to a rectangular area of 2500m by 1000m (one square mile).

Non-Criteria Pollutant Sources - There are a set of pollutants from three “distinct” sources in the Marcellus shale operations for which there are no national ambient standards, but for which New York State has established either a state standard (H_2S) or toxic guideline concentrations. These are VOC species and HAPs which are emitted from: a) sources associated with venting of gas prior to the production phase, b) as by-products of combustion of gas or fuel oil, and c) the additives which exist in flowback water impoundments. A review of the data on these pollutants and their sources indicated that the three distinct source types can be modeled independently, as described below.

First, of the sources which vent the constituents of the “wet” gas (if it is encountered), the flowback venting has by far the most dominant emissions of the toxic constituents. The other two sources of gas venting are the mud-gas separator and the dehydrator, and a comparison of the relative emissions of the five pollutants identified in the industry report (benzene, hexane, toluene, xylene, and H_2S) from these three sources in Tables 8, 21 and 22 shows that the flowback venting has about two orders of magnitude higher emissions than the other two sources. As noted in the industry report, this venting is limited to a few hours before the flare is used, which reduces these emissions by over 90%. Thus, modeling was used to determine the short-term impacts of the venting emissions. Annual impacts were not modeled, due to the very limited time frame for gas venting, even if ten wells are to be drilled at a pad.

It was determined that during these venting events, essentially no other emissions of the same five toxics would occur from other sources. That is, even though a subset of these pollutants are also tabulated in the industry report at relatively low emissions for the engines, compressors and the flares, it is either not possible or highly unlikely that the latter sources would be operating simultaneously with the venting sources (e.g. gas is either vented or flared from the same stack). Thus, for the short-term venting scenario, only the impacts from the three sources need to be considered. It was also determined that rather than modeling each of the five pollutant for the set of the venting sources for each of the twelve meteorological years, the flowback venting source parameters of Table 15 were used with a unitized emission rate of 1 g/s as representative of all three sources. The actual pollutant specific impacts were then scaled with the total emissions from all three sources. This is an appropriate approximation, not only due to the dominance of the flowback vent emissions, but also since the stack height and the calculated plume heights for these sources are very similar. This simplification significantly reduced the number of model runs which would otherwise be necessary, without any real consequence to the identification of the maximum short-term impacts.

The next set of non-criteria pollutants modeled included those resulting from the combustion sources. It should be clarified that pollutants emitted from the glycol dehydrator (e.g. benzene), which are associated with combustion sources were also included in these model calculations for both the short-term and annual impacts. A review of the emissions in Tables 8, 18, 21, and 24 indicates seven toxic pollutants with no clear dominance of a particular source category. Furthermore, the sources associated with these pollutants have much more variability in the source heights than for the venting scenario. For example, the flare emissions of the three pollutants in Table 21 are higher than for the corresponding frac pump engines, but the plume from the flame is calculated to be at a much higher level than those for the engines or compressors such that a “representative” source could not be simply determined in order to be able to model a unitized emission rate and limit the number of model runs.

However, it was still possible to reduce the number of model calculations from another standpoint. The seven pollutants associated with these sources were ranked according to the ratios of their emissions to the corresponding 1 hour SGCs and AGCs (SGCs for hexane and propylene were determined by Toxics Assessment section since these are not in DAR-1 tables). These ratios allowed the use of any clearly dominant pollutants which could be used as surrogates to identify either a potential issue or compliance for the whole set of toxics. These calculations indicated that benzene and formaldehyde are clearly the two pollutants which would provide the desired level of scrutiny of all of the rest of the pollutants in the set. To demonstrate the appropriateness of this step, limited additional modeling for the annual impacts for acetaldehyde was also performed due to the relatively low AGC for this pollutant. These steps further reduced the number of model runs by a significant number.

The emission parameters, downwash structure dimension and the location of the sources were the same as for the criteria pollutant modeling. Similar to the case of the criteria pollutants, any necessary adjustments to the annual emission rates to provide more realistic annual impacts were made after the results of the initial modeling were reviewed to determine the potential for adverse impacts. These considerations are further discussed in the resultant impact section.

The last set of non-criteria pollutant modeling dealt with the set of chemicals added to the hydraulic fracturing water during the completion phase of operations. For the potential emissions and impacts of these various additives which could end up in the flow back impoundments, a different approach had to be taken. As noted previously, according to ICF report and industry, no air emissions were provided since they believed these air emissions to be negligible due to the extremely low concentrations of these chemicals in the flowback water. However, both theory and practice indicate that atmospheric transfer of chemicals in water impoundments clearly occurs, albeit at low concentrations, and it is only prudent to quantify these emissions in order to explicitly determine the consequent impacts.

The Department has performed a limited, yet representative, analysis of the air impacts of the various chemicals identified in the additives to the hydraulic fracturing water. The purpose of the Department's analysis is to use a selected set of chemicals from a large list proposed for use by industry to determine whether there is a potential for any adverse effects from their release into the atmosphere and, if so, what mitigation measures might be necessary. To date, industry has identified a large number of compounds which serve various purposes during the hydraulic fracturing process that might be used in well completion operations. In addition, industry has supplied DEC with compound specific chemical compositions (including "inert" additives) and their percentages which make up these compounds. These latter "additives" essentially fall into one of the categories identified with a "purpose", as depicted in Figure 6.6, which is a typical percent-by-weight representation of the fracturing water/proppant/additive mix provided by Chesapeake Energy. There are likely certain variations in these percentages within the industry and specific operations, but these are deemed relatively small within the context of the modeling and the conservative steps taken to estimate emissions. In addition, these have been checked against certain actual data used, as described below. The specific purpose of the additives is described in Chapter 5.

It is seen that these various compounds make up about 1% of the overall water, proppant (e.g. sand) and the additives mix, but these could, nonetheless, contain chemicals with very low ambient concentration thresholds of concern. The first criterion in choosing the chemicals to model was to assure that each of these additives was represented. Since there was a large number of proposed products for each category of additive and these, in turn, have even a larger set of specific chemical components within each product, a set of additional criteria was needed to identify the practical set to be modeled. To assure that the purpose of the Department's modeling exercise was achieved (i.e. that of identifying if any potential for adverse effects could occur), the following criteria were also used to further assure additive representation:

1) The pollutant has a relatively low ambient threshold and, thus, is of potential exposure concern. To that end, a list was provided by NYSDOH staff of specific pollutants which had water and air "high" risk concerns. These included Amides, VOC species, and glycols. In addition, DEC's Air Guide-1 tables of SGCs and AGCs we referenced to identify pollutants with low ambient threshold values.

2) The chemical had to have an established threshold or one for which it could be relatively easily established in order for the modeled concentrations to be compared to a concern level. It should be noted that, although the majority of the chemicals had SGCs or AGCs listed, a considerable number did not.

3) The chemical with the lower ambient threshold was used as representative of that class of additives if the amounts to be used were essentially the same or when the "quantity" factor was more than balanced by the "low threshold" factor. Examples were the bactericide glutaraldehye, which has rather low SGCs and AGCs, and methanol, with lower SGC and AGC than another surfactant, such as isopropanol.

4) The specific chemical appeared frequently or was a component of more than one additive. For example, ethylene glycol was listed as a component of iron and clay inhibitor, crosslinker and scale inhibitor.

5) Certain chemicals with small amounts (<5%) in the compounds, were still considered if these were known high toxicity pollutant of concern; for example benzene and formaldehyde.

Using the above criteria, the list of the representative chemicals in Table 6.13 was generated. Although this is not a complete list of the very large set of chemicals in the compounds, DAR believes these are adequate for the current modeling purposes. It is important to note, however, that a few compounds identified in the final submission from industry included certain pollutants with higher toxicity concerns (e.g. benzene and xylene) and at much larger quantities than identified previously. There were a handful of such entries and these were associated specifically with either "solvents" or "surfactants". Since the former does not show up in Figure 6.6, DMN staff contacted industry and industry representatives clarified that these solvents were included in the list to be comprehensive, but would not be used (in addition to a set of other solvents) for "slickwater" hydraulic fracturing in the Marcellus Shale in New York. In addition, the specific surfactant with the benzene content will also not be used in New York. Thus, it will be necessary to either omit these compounds from the list to be used in New York or require further site specific analysis for a given multi-pad area to address consequent impacts. Given that there was only one remaining entry with benzene at minute percentages, as noted below, the implication is that this chemical should not be used in any additive for hydraulic fracturing water mix in New York.

Table 6.13 gives the purpose for which the chemical appears in a compound as noted in Figure 6.6, with some chemicals noted to be used for multiple purposes. The "percent of the agent" data is also taken from Figure 6.6, with two modifications. First, for chemicals which appear in different agents and which could be found simultaneously in the hydraulic fracturing water, an attempt was made to account for the larger quantity of the chemical in the total mix. For example, ethylene glycol is noted to be used in four agents and the percentages of these agents from Figure 6.6 were added to the extent that this chemical was found to essentially have the same "amount" as percentage in compounds in all of these agents. The second modification relates to the bactericides. In an attempt to check the consistency of the percentages in Figure 6.6 with available actual data from industry on the fracturing water/additive mixes from Marcellus wells in Pennsylvania and West Virginia, it was noted that the percentages of the various agents verified well, except for the bactericides. For the latter, the data consistently showed much higher percentages; in the range of 0.02 to 0.03% versus the 0.001% in Figure 6.6. Thus, a conservative value of 0.03% was used in the Department's calculations.

Table 6.13 also lists the maximum percentage of the chemicals noted from all of its entries in the data provided by industry. In most instances there was fairly small variation in these percentages, but in entries with larger variations, the maximum percent of chemical in the compound was used. In a few cases there were only one or two entries. For example, benzene was listed only at 0.0001 % in one compound, keeping in mind the caveat noted previously on compounds not to be used for the subject well completions.

Multiplying the data in columns 4 and 5 (in fractions) and unit conversions gives the maximum concentration of the specific chemical in column 6 of Table 6.13. These data are then used in the emissions calculations. The last two columns in Table 6.13 provide the 1 hour SGC and annual AGC values used to compare the resultant impacts. It is noted that four of the chemicals did not have a SGC or AGC tabulated in the Department's DAR-1 tables. For these, the noted values were developed by DAR's Toxics Assessment Section with assistance from NYSDOH.

To calculate emission rates of these chemicals, the Department has relied upon an EPA document44 on emissions from water treatment facilities which provide such methods for surface impoundments. These emissions can be used in the Department's modeling analysis for the two different impoundment sizes. The document provides a set of equations for different source categories, and the Department has relied upon the equations in Section 5 for surface impoundments to calculate emissions. In particular, the equation in Section 5.2 for quiescent water emissions is used, including total gas and liquid phase transfer coefficients, with the concentration of the pollutant in the water and the surface area of the impoundments as inputs. The model is based on the concept that the transfer of these "impurities" from the water to the atmosphere is dependent upon the rate at which atmospheric and chemical/physical properties of these chemicals affect the release into the air. These latter parameters are, in turn, dependent mainly on factors such as wind speed and the gas and liquid phase solubility and mobility in water of the chemicals. For example, the more soluble a chemical is in water, the less of it is available to transfer to the air, while the higher the wind speed, the more the chemical will experience a transfer out of the water due to the "friction effects" of the wind. In addition to these transfer coefficients, the emission is linearly related to the concentration of the chemical in the water.

In order to calculate the gas phase transfer, the partitioning coefficient is determined from a simplified equation which only requires Henry's law constant (H). These latter are tabulated in Appendix C of the EPA report for many compounds. For the compounds which the Department has chosen to analyze in its modeling and for which H values are not given in the report, the Department has obtained appropriate values with assistance from NYSDOH staff. It should be noted that these values are representative of standard conditions and no attempt is made to account for any dependency on factors such as temperature. This is deemed more than adequate for the Department's purposes.

In addition, both the gas and liquid phase transfer coefficient equations in Table 5-1 of the EPA report require values of air and water diffusivities which were also obtained either from Appendix C or provided by NYSDOH staff. Limited NYSDOH data reflected more recent experimental values. These transfer coefficient equations also require the length, "diameter" and depth of the impoundments and the Department has used, respectively, values of the longer length, an equivalent diameter calculated from the areas, and a depth of about three meters(as provided by industry). These result in values of fetch/depth of 50 and 15 and effective diameter of 170m and 30m for the off-site and onsite impoundments, respectively, as inputs to the appropriate equations.

Both the liquid and gas phase transfer coefficients are dependent on wind speed, with the former being more sensitive to this parameter. For both practical and theoretical reasons, the Department has not attempted to vary these coefficients with the wind speed data used in the meteorological data bases. Instead, the Department has used a constant "average" wind speed based on the consideration of the expected high impacts and the Springer, et al formulations in Table 5-1 for the liquid phase. First, there are different formulations for wind speeds above or below 3.25m/s, with no real dependence of the liquid phase coefficient on wind speeds below this value. In addition, it is commonplace that the highest impacts from ground level sources are associated with lower wind speeds. Since the transfer coefficient (and emission rate) is directly related to wind speed, while the ambient concentration for ground level sources is inversely related to wind speed, the Department has chosen the 3.25 m/s value as a balance between these two effects. Although annual average wind speeds at many sites are at or above 5m/s, the lower choice of average wind speed assures that the Department has estimated realistic, yet still conservative values of emissions associated with the conditions of higher expected impact.

With these calculated parameters, emission estimates are made for the two impoundments using their corresponding areas and the concentration of each chemical determined from the percent of the chemical in the flowback water. These latter values are simply the product of the percent in compound and the percent of the compound in water (in fractions) noted in Table 6.13.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. A limited number of chemical samples of flowback water made available to DEC do not contain or were not analyzed for a majority of the compounds the Department has modeled and, thus, "actual" data could not be used to verify the emissions. Even if such data were available, issues would still need to be resolved with adequacy of data samples and representativeness of these samples for Marcellus shale drilling in New York.

The calculated emissions were then used to predict maximum 1 hour and annual impacts from the two impoundments. However, unlike combustion and venting source scenarios discussed above, the annual impacts were not adjusted for any operational restrictions, especially for the "centralized" impoundment since some of the industry has indicated a desire to keep these open for up to three years. There is, however, little specific information on the potential reuse of the flowback water which can then be incorporated in the determination of more realistic annual emissions. Thus, it is likely that annual emissions could be somewhat overstated in the modeling, but given the lack of any limitation of the operational restrictions on the flowback water, the modeling had to be performed for the worst case scenario of emissions occurring for a full year. Some consideration is given to pollutant-specific emission rates on an annual basis in the discussions of the resultant impacts.

Pollutant Averaging Times, Ambient Thresholds and Background Levels

The AERMOD model calculates impacts for each of the hours in the meteorological data base at each receptor and then averages these values for each averaging time associated with the ambient standards and thresholds for the pollutants. For example, particulate matter (PM10 and PM2.5) has both 24-hour and annual standards, so the model will present the maximum impact at each receptor for these averaging times. As the form of the standards cannot be exceeded at any receptor around the source, the model also calculates and identifies the overall maximum impacts over the whole set of receptors.

For the set of pollutants modeled, the averaging times of the standards are: for S02- 3hour, 24 hour, and annual; for PM10/PM2.5-24 hour and annual; for NO_2-annual; for CO-1 hour and 8 hour; and for the set of toxic pollutants- 1hour SGCs and annual AGCs. For most criteria pollutants, the annual standards are defined as the maxima not to be exceeded at any receptor, while the short-term standards are defined at the highest-second-highest (HSH) level wherein one excedence is allowed per receptor. The exception is PM2.5 where the standards are defined as the 3 year averages, with the 24 hour calculated at the 98th percentile level. The toxic pollutant SGCs and AGCs are defined at a level not be exceeded. In the Department's assessments, the maximum impacts for all averaging times were used for all pollutants, except for PM2.5, in keeping with modeling guidance for cases where less than five years of meteorological data per site is used.

In addition to the standards, EPA has defined levels which new sources or modifications after a certain time frame cannot exceed and cause significant deterioration in air quality in areas where the observations indicate that the standards are being met (known as attainment areas). The area depicted in Figure 6.4 for the Marcellus Shale has been classified as attainment for all of the pollutants modeled in the Department's analysis. Details on area designations and the state's obligation to bring a nonattainment area into compliance are available at DEC's public webpage as well as from EPA's webpage45. For the attainment areas, EPA's Prevention of Significant

[45] See: http://www.dec.ny.gov/chemical/8403.html and http://www.epa.gov/ttn/naaqs/.

Deterioration (PSD) regulations currently define increments for SO_2, NO_2 and PM10. Although, in the main, the PSD regulations apply only to major sources, the increments are consumed by both major and minor sources and must be modeled to assure compliance. However, the PSD regulations also exempt "temporary" sources from having to analyze for these increments. It is judged that essentially all of the emissions at the well pad (which are individually defined as a "source" for applicability purposes) can be qualified as such since the expectation is that the maximum number of wells at a pad can be drilled and completed within a year. Even if partial set of the wells is drilled in a year and these operations cease, the increment would be "expanded" as allowed by the regulations.

The only exception to the temporary designation would be the offsite compressor and the line heater which can operate for years. Thus, only these two sources were considered in the increment consumption analysis. The applicable standards and PSD increments are presented in Table 6.14 for the various averaging times. In addition to these standards and increments, the table provides EPA's defined set of Significant Impact Levels (SILs) which exist for most of the criteria pollutants. These SILs are at about 2 to 4 percent of the corresponding standards and are used to determine if a project will have a "significant contribution" to either an existing adverse condition or will cause a standards violation.

These SILs are also used to determine whether the consideration of background levels, which include the contribution of regional levels and local sources, need to be explicitly addressed or modeled. When the SILs are exceeded, it is necessary to explicitly model nearby major sources in order to establish potential "hot spots" of exceedences to which the project might contribute significantly. For the present analysis, if the SILs are exceeded for the single multi-well pad, the Department has considered the potential for the contribution of nearby pads to the impacts of the former on a simplified level. The approach used was noted previously and involves the modeling of a nearby pad placed at 1000m distance from the pad for which detailed impacts were calculated, in order to determine the relative contribution of the nearby pad sources. If these results indicate the potential for significant cumulative effects, then further analysis would need to be performed.

On the other hand, in order to determine existing criteria pollutant regional background levels, which must be explicitly included in the calculation of total concentrations for comparison to the standards, the Department has conservatively used the maximum observations from a set of DEC monitoring sites in the Marcellus Shale region depicted in Figure 6.4. The location of these sites and the corresponding data is available in the DEC public webpage.46 The Department has reviewed the data from these sites to determine representative, but worst case background levels for each pollutant. The Department has used maximum values over a three year period from the latest readily available tabulated information from 2005 through 2007 from at least two sites per pollutant within the Marcellus shale area, with two exceptions. First, in choosing these sites, the Department did not use "urban" locations, which could be overly conservative of the general areas of well drilling. This meant that for NO_2 and CO, data from Amherst and Loudonville, respectively, were used as representative of rural areas since the rest of the DEC monitor sites were all in urban areas for these two pollutants. Second, data for PM10 for the period chosen was not available from any of the appropriate sites due to switching of these sites to PM2.5 monitoring per EPA requirements. Thus, the Department relied on data from 2002-04 from Newburgh and Belleayre monitors. The final set of data used for background purposes are presented in Table 6.15. These data represent worst case estimates of existing conditions to which the multi-well pad impacts will be added in order to determine total concentrations for comparison to the AAQS. In instances where the use of these maxima causes an exceedence of the AAQS, EPA and DEC guidance identify procedures to define more case specific background levels. Per DEC Air Guide-1, since there are no monitoredbackground levels for the non-criteria pollutants modeled, the impacts of H_2S and rest of the toxic chemicals are treated as incremental source impacts relative to the corresponding standard and SGCs/AGCs, respectively. Determinations on the acceptability of these incremental impacts are then made in accord with the procedures in Air Guide-1.

6.5.2.4 Results of the Modeling Analysis

Using the various model input data described previously, a number of model calculations were performed for the criteria and toxic pollutants resulting from the distinct operations of the onsite and offsite sources. Each of the meteorological data years were used in these assessments and the receptors grids were defined such as to identify the maxima from the different sources. In some instances, it was possible to limit the number of years of data used in the modeling, as results from a subset indicated impacts well below any thresholds. In other cases, it was necessary to expand

[46] See: http://www.dec.ny.gov/chemical/8406.html

the receptor grid such that the decrease in concentration with downwind distance could be determined. These two aspects are described below in the specific cases in which they were used.

As described in the previous section, initial modeling of annual impacts was performed in the same model runs as for the short-term impacts, using the maximum emission rates. However, in a number of cases, this approach lead to exceedences of annual thresholds and, thus, more appropriate annual emissions were determined in accord with the procedures described in Section 6.5.2.3, and the annual impacts were remodeled for all of the data years. These instances are also described below in the specific cases in which the annual emissions were used. The results from these model runs were then summarized in terms of maxima and compared to the corresponding SILs, PSD increments, ambient standards, and Air Guide-1 AGCs/SGCs.

This comparison indicated that, using the emissions and stack parameter information provided in the industry report, a few of the ambient thresholds could be exceeded. Certain of these exceedences were associated with conditions (such as very low stacks and downwash effects) which could be rectified relatively easily. Thus, some additional model runs were performed to determine conditions under which the ambient thresholds would be met. These results are presented below with the understanding that industry could implement these or propose their own measures in order to mitigate the exceedences. Results for the criteria pollutants are discussed first, followed by the results for the toxic/non-criteria pollutants.

Criteria Pollutant Impacts

The set of sources identified in Table 6.11 for short-term simultaneous operations of the various combustion sources with criteria pollutant emissions were initially modeled with the maximum hourly emission rate and one year of meteorological data. It was clear from these results that the annual impacts for PM and NO_2 had to be recalculated using the more appropriate annual emissions procedures discussed in Section 6.5.2.3. That is, for these pollutants, the "average" rates in the industry report were scaled by the number of days/hours of operations per year for the drilling engine/compressor, the hydraulic fracturing engines and the flare, and then these results were multiplied by ten to account for the potential of ten wells being drilled at a pad for a year. The rest of the sources were modeled assuming full year operations at the maximum rates. In addition, based in part on the initial modeling, two further adjustments were made to the annual NO_2 impacts. First, the model resultant impacts were multiplied by the 0.75 default factor of the tier 2 screening approach in EPA's modeling guidelines. This factor accounts for the fact that a large part of emissions of NOx from combustion sources are not in the NO_2 form of the standard. The second adjustment related to the stack height of the off-site compressor, which was raised to 7.6m (25ft) based on the results for the non-criteria pollutants discussed below; that is, this height was deemed necessary in order to meet the formaldehyde AGC.

Each of the meteorological data years was used to determine the maximum impacts for all of the criteria pollutants and the corresponding averaging times of the standards. However, in the case of 24 hour particulate impacts, modeling was limited to the initial year (Albany, 2007) for reasons discussed below. The results for each year modeled are presented in Table 6.16. It should be noted that the SO_2 annual impacts in this table are based on the maximum hourly rates and are very conservative. In addition, the tabulated values for the 24-hour PM2.5 impacts are the eight highest in a year, which is used as a surrogate for the three year average of the eight highest value (i.e., 99^{th} percentile form of the standard). It is seen that the short-term impacts do not show any significant variability over the twelve years modeled.

The overall maxima for each pollutant and averaging time from Table 6.16 are then transferred to Table 6.17 for comparison to the set of ambient thresholds. These maximum impacts are to be added to the worst case background levels from Table 6.15 (repeated in Table 6.17), with the sum presented in the total concentration column. The impacts of only the compressor and the line heater are also presented separately in Table 6.17 for comparison to the corresponding PSD increments. It should be noted that, due to the low impacts for many of the pollutants from all of the sources relative to the increments, only the 24-hour PM10 and annual NO_2 were recalculated for the compressor and line heater, as noted in Table 6.17. The rest of the impacts are the same as those in the maximum overall impact column. The results indicate that all of the ambient standards and PSD increments will be met by the multiple well drilling activities at a single pad, with the exception of the 24 hour PM10 and PM2.5 impacts. In fact, the 3 hour (and very likely the annual) SO_2 impacts are below the corresponding significant impact levels. This is a direct result of the use of the ultra low sulfur fuel assumed for the engines, which will have to be implemented in these operations. In addition, the level of compliance with standards for the maximum annual impacts for NO_2 and PM2.5 are such as to require the implementation of the minimum 7.6m (30ft) stack height for the compressor and general adherence to the annual operational restrictions identified in the industry report.

Table 6.16 results for 24 hour PM10 and PM2.5 impacts were limited to one year of meteorological data since these were found to be significantly above the corresponding standards, as indicated in Table 6.17. Unlike other cases, a simple adjustment to the stack height did not resolve these exceedences and it was determined that specific mitigation measures will need to be identified by industry. However, the Department has determined one simple set of conditions under which impacts can be resolved. It was noted that the relatively large PM10/PM2.5 impacts occurred very close to the hydraulic fracturing engines (and at lower levels near the rig engines) at a distance of 20m, but there was also a very sharp drop-off of these concentration with distance away from these sources. Specifically, to meet the standards minus the background levels in Table 6.17, it was determined that the receptor distance had to be beyond 80m for PM10, and 500m for PM2.5. The latter distance can be lowered in recognition of the fact that the background levels used for these calculations are worst case and can be adjusted using EPA procedures.

In an attempt to determine if a stack height adjustment in combination with a distance limitation for public access approach can alleviate the exceedences, the rig engine and fracturing engine stacks heights were both extended by 3.1m (10ft). From the photographs of the truck-mounted engines, it was not clear if any extensions would be practical and, thus, only this minimal increase was considered. This scenario was modeled again with the Albany 2007 meteorological data. The resultant maximum impacts were reduced to 171 and 104 μg/m3 for PM10 and PM2.5, respectively. For this case, in order to achieve the standards using Table 6.17 background levels, the receptors must be beyond 40m and 500m for PM10 and PM2.5, respectively. Thus, the stack height extension did not significantly affect the concentrations at the farther distances, as would be expected from the fact that building downwash effects are largest near the source. However, the background level for PM2.5 can be adjusted from the standpoint that the expected averages associated with these operations at relatively remote areas are better represented by the regional component due to transport. If the contribution of the latter to the observed maxima is conservatively assumed to be half of the value in Table 6.17 (i.e., 15 μg/m3), then the receptor distance at which a demonstration of compliance can be made is approximately 150m. This seems to be a more practical location at which a fence or a similar measure can be imposed in order to preclude public exposure.

Thus, one practical mitigation measure to alleviate the PM10 and PM2.5 standard exceedences is to raise the stacks on the rig and hydraulic fracturing engines and/or erect a fence at a distance surrounding the pad area in order to preclude public access. Without further modifications to the industry stack heights, a fence out to 500m would be required, but this distance could be reduced to 150m with the taller stacks and a redefinition of the background levels. Alternately, there is likely control equipment which could significantly reduce particulate emissions. The set of specific control or mitigation measures will need to be addressed by industry.

An additional issue addressed in a simplified manner was the possibility of simultaneous operations at a nearby pad, which could be located at a minimum distance of one km from the one modeled, as described previously. It is highly unlikely than more than one additional pad would be operating as modeled simultaneously with other pads within this distance; it is more likely that drill rigs and other heavy equipment will be moved from one pad to another within a given vicinity, with sequenced operations. Regardless, the impacts of all the pollutants and averaging times were determined at a distance of 500m from the modeled well pad for the years corresponding to the maximum impacts. This is half the distance to the nearest possible pad and allows the determination of potential "overlap" in impacts from the two pads. The concentrations at 500m drop off sharply from the maxima to below significance levels for almost all cases such that nearby pad emissions would not significantly contribute to the impacts from the modeled source. These impacts at 500m are presented in the last row of Table 6.16 and their comparisons to the corresponding SILs in Table 6.17 show only the 24-hour PM2.5 and annual NO_2 impacts are still significant at this distance.

Thus, there is a potential that for these two cases the nearby pad operations could contribute to another well operation's impacts. This scenario was assessed by placing an identical set of sources at another pad at a distance of 1km from the one modeled in the general upwind direction from the latter. Impacts were then recalculated on the same receptor grid using the years of modeled worst case impacts for these two pollutants and averaging times. The results indicated that the maximum impacts presented in Table 6.17 for annual NO_2 and 24 hour PM2.5 were essentially the same; in fact the 24 hour PM2.5 impacts are identical to the previous maxima while the NO_2 annual impact of 63.2 increased by only 1.2 µg/m3. Annual Impacts from any other pad not in the predominant wind direction would be lower. These results are judged not to effect the compliance demonstrations discussed above. Thus, it is concluded that minimal interactions from nearby pad well drilling operations would result, even if there were to be such simultaneous operations.

Therefore, compliance with standard and increments can be adequately demonstrated on individual pad basis.

Non-Criteria Pollutant Impacts.

As discussed in Section 6.5.2.3, three “distinct” source types were independently modeled for a corresponding set of toxic pollutants: i) short-term venting of gas constituents, ii) combustion by-products, plus the emissions of the same pollutants from the glycol dehydrator, and iii) a set of representative chemicals from the flowback impoundments. These impacts were determined for comparison to both the short-term 1 hour SGC and annual AGC, with the exception of the venting scenario which was limited to the short-term impacts due to the very short time frame of the practice. The gas venting emissions out of three sources (mud-gas separator, flowback venting, and the dehydrator) are essentially determined by the flowback phase. It was thus possible to model only this source with a unitized emission rate (1g/s) and then actual 1 hour impacts were scaled using the total maximum emission rates.

Each year of meteorological data was modeled with the flowback vent parameters to determine the maximum 1 hour impacts for 1 g/s emission rate. These results were then reviewed and the maximum overall normalized impact of 641 µg/m3 (for Albany, 2008 data) was calculated as the worst case hourly impact. Using the total emissions from all three sources for each of the vented toxic pollutants, as presented in Table 6.18, along with this maximum normalized impact, results in the maximum 1 hour pollutant specific values in the third column of Table 6.18. The pollutants “shaded out” in the table are not vented from these sources. It is seen that all of the worst case 1 hour impacts are well below the corresponding SGCs, but the maximum 1 hour impact of 61.5 µg/m3 for H_2S (underlined top entry in the box) is above the New York standard of 14 µg/m3.

Thus, if any “wet” gas is encountered in the Marcellus Shale, there will be a potential of exceedence of the H_2S standard. The maximum one hour impact occurred relatively close to the stack, and, in order to alleviate the exceedence, ambient air receptors must be excluded in all areas within at least 100m of the stack. Alternately, it is possible to also reduce this impact by using a stack height which is higher than the conservative 3.7m (12ft) height provided in the industry report. Iterative calculations for the year with the maximum normalized impact indicated that a minimum stack height of 9.1m (3 0ft) would be necessary to reduce the impact to the 12.1 µg/m3 value for H_2S reported in the "Max 1 hour" column of Table 6.18. With this requirement, all venting source impacts will be below the corresponding SGCs and standard.

For the set of seven pollutants resulting from the combustion sources and the dehydrator, it was previously argued that it was only necessary to explicitly model benzene and formaldehyde, along with the annual acetaldehyde impacts, in order to demonstrate compliance with all SGCs and AGCs for the rest of the pollutants. The relative levels of the SGCs and AGCs presented in Table 6.18 for these pollutants and the corresponding emissions in the industry report tables clearly show the adequacy of this assertion. For the modeling of these pollutants, the maximum short-term emissions were used for the 1 hour impacts, but the annual emissions were used for the AGCs comparisons. The annual emissions were determined using the same procedures as discussed above for the criteria pollutants.

An initial year of meteorological data which corresponded to the worst case conditions for the criteria pollutants was used to determine the level of these impacts relative to the SGCs and AGCs before additional calculations were made. The results of this initial model run are presented in right hand set of columns of Table 6.18. These indicate that, while the 1-hour impacts are an order of magnitude below the benzene and formaldehyde SGCs and the acetaldehyde AGC, there were exceedences of the AGCs for the former two pollutants (the top underlined entries for each pollutant in the maximum annual column). It was determined that these exceedences were each associated with a particular source: the glycol dehydrator for benzene and the offsite compressor for formaldehyde. It should be noted that these exceedences occur even when the emissions from dehydrator are controlled to be below the National Emissions Standard for Hazardous Air Pollutants (NESHAP) imposed emission rate provided in Table 22 of the industry report and with 90% reduction in formaldehyde emissions accounted for by the installation of an oxidation catalyst, as will be shortly required as noted in the industry report. To assure the large margin of safety in meeting the benzene and formaldehyde SGCs and the acetaldehyde AGC, another meteorological data base was used to calculate these impacts. The results in Table 6.18 did not change from these calculations. Thus, it was determined that no further modeling was necessary for these. On the other hand, for the benzene and formaldehyde AGC exceedences, a few additional model runs were performed to test potential mitigating measures. It is clear that, similar to the criteria pollutant impacts, these high annual impacts are partially due to the low stacks and the associated downwash effects for both the dehydrator and the compressor sources. Given that these two sources already need to include NESHAP control measures, the necessary additional reduction in impacts can be practically achieved only by limiting public access to about 150m from these sources, or by raising their stacks.

An iterative modeling of increased stack heights for both the dehydrator and the compressor demonstrated that in order to achieve the corresponding AGCs, the stack of the dehydrator should be a minimum of 9.1m (3 0ft), in which case it will also avoid building downwash effects, while the compressor stack must be raised to 7.6m (25ft). These higher stacks were then modeled using each of the 12 years of meteorological data and the resultant overall maxima, tabulated in the bottom half of the "Max annual" column in Table 6.18. It should be noted that these modifications to stack height will also reduce the corresponding 1 hour maxima leading to a larger margin of compliance with SGCs. With these stack modifications and the NESHAP control measures identified in the industry report, all of the SGCs and AGCs are projected to be met by the various combustion operations and the dehydrator.

The last set of toxic pollutants modeled was the representative subset of additive chemicals used in hydraulic fracturing operations for the onsite and centralized impoundments. The impacts of the set of representative pollutants in the flowback water in Table 6.13 were modeled using a unitized (1 g/s) emission rate which is input to the model on a per unit area basis (m^2) for the area source modeling. The 1-hour and annual "normalized" (at 1 g/s) impacts for each impoundment was then determined for each of the meteorological data years, and then the overall maxima were used with the actual emissions of each pollutant to calculate the actual pollutant concentrations. The "normalized" impacts for each year of the data and the overall maxima are presented in Table 6.19. Note that these values are merely "non-dimensionalized" entries not related to actual emissions of the impoundments.

The actual emission rates for the chemicals were calculated from the corresponding water concentrations from Table 6.13, the transfer coefficients calculated per the procedures discussed in Section 6.5.2.3, and the area of the two impoundments, using the equation in Section 5.2 of the aforementioned EPA report. These emissions are presented in column 2 of Table 6.20. The maximum overall unitized impacts from Table 6.19 for each averaging time and impoundment size were then used to calculate the corresponding maximum 1 hour and annual impacts. These maximum impacts and the associated SGCs/AGCs are presented in Table 6.20.

It is seen that the impacts due to the larger off-site impoundment are higher than those of the smaller on-site one, as would be expected from larger emissions and the "accumulation" of concentrations at the edge of the area source. The ratios of maximum 1 hour impacts to the SGCs and maximum annual impacts to the AGCs are also presented in Table 6.20. In this way, any values above one (which are underlined) indicate an exceedance of an SGC or AGC. The results indicate that the 1hour impacts for most of the chemicals are below the corresponding ambient SGC thresholds. However, the impacts of glutaraldehyde, methanol and heavy naphtha are above the SGCs due to the relatively low value of the SGC for the former and the relatively large concentrations in water for the latter two.

Similarly, the ratios of the annual impacts to the corresponding AGCs indicate a larger number of exceedences; for the central impoundments, five of the 13 chemicals modeled exceed the AGCs, while three of the chemicals are within a factor of two of the AGCs. As discussed previously, it is important to recognize that annual impacts from these impoundments assume quasi-continuous emissions based on limited industry information on the disposition or reuse of the flowback water over the long term and for the multiple wells which could be potentially drilled and completed during a given year. Thus, it is possible that the annual impacts could be overstated, especially for the onsite impoundment, which is less likely to be in a "continuous" mode of operations. In addition, even for the central impoundment, certain pollutants (methanol and heavy naphtha) are emitted at relatively large rates and quantities due to their low solubility in water and large concentrations in the flowback water. For these pollutants, the short-term emission rate in Table 6.20 could be difficult to be maintained over a year without a rather short "replenish" time frame. On the other hand for other pollutants (e.g. acrylamide and glutaraldehyde), the emissions are low enough such that these could be easily maintained over the long term. These considerations have been included in the following discussions of the consequences of these impacts.

It should be noted that all of the SGC and AGC maximum impacts occur near the edge of the impoundments, at the closest receptor of 10 m distance, as expected for these ground level sources. Thus, one of the possible ways to alleviate these impacts is to assure that there is no public access to areas at which the SGCs/AGCs are exceeded. The simplest way to accomplish this is to use the largest of the 1 hour and annual exceedences to calculate a distance at which all of the exceedences would be eliminated, with an imposition of a verifiable exclusion zone. However, it is also possible to eliminate some of these exceedences on a pollutant specific basis by other means, such as eliminating or limiting the use of the compounds with the chemicals at the amounts modeled to cause the exceedance. Table 6.20 indicates a set of approximate “factors” of exceedences which were used to calculate pollutant specific distances from the four years meteorological data associated with the two impoundments and two averaging times identified in Table 6.19. As noted previously, the denser receptor grid used near the impoundments was extended out to 1km for these specific model runs in order to accomplish this task.

The distances from the impoundments at which all of the SGCs and AGCs would be just met for the set of pollutants with exceedences are summarized in Table 6.21. For example, a factor of 2 was used to approximately represent all three ratios close to this value for the annual impacts for the on-site impoundment in Table 6.20. For the onsite impoundment, Table 6.21 indicates that SGC exceedences can be eliminated by erecting a fence (or a similar enforceable measure) at a distance of approximately 140m from its edge in order to preclude public access to the areas of exceedance. Alternately, any gelling agent with heavy naphtha could be eliminated in the hydraulic fracturing water mix, which will result in a somewhat smaller exclusion zone since the rest of the compounds identified to date indicate chemicals with lower ambient thresholds (e.g., guar gum). It is also noted from Table 6.21 that the 140m “fence” distance would alleviate the AGC exceedences for the onsite impoundment. On the other hand, if removal of flowback water from these impoundments or other measures to reduce air emissions could be affected such that emissions would be significantly limited over a year, then the AGC comparisons can be either adjusted or removed accordingly.

For the central off-site impoundment, Table 6.21 shows relatively larger distances for both the SGC and AGC exceedences. In this case, the annual impacts could be more likely realized due to the desire on the part of certain industry to keep these impoundments “open” for up to three years without any mitigation or control measure, and since these could be in quasi-continuous mode of operation in serving a number of well pads. For the 1 hour impacts, the SGC exceedences occur out to relatively large distances, making the imposition of public access restrictions by a fence or similar measure less practical as the only control measure. Thus, restrictions on the chemical use or their concentrations would be the more likely mitigation options. For the annual modeling results, the worst case meteorological data base (Buffalo, 2007) was used to generate a graph which depicts the areas in which the concentrations of the pollutants exceed AGCs. The distances at which the concentrations meet the approximate factors in Table 6.21 were defined as isopleths (lines of constant concentrations) around the impoundment.

The result is presented in Figure 6.7 for all pollutants which exceed the AGCs. The color coded receptors (each "dot" is a receptor on the figure) determine the areas within which the annual impacts are above the AGCs for the chemical noted in the legend. For example, the "deep purple" colored area was calculated by looking for the distance beyond which the maximum impact for methanol need to be reduced by a factor of two per Table 6.21. These results indicate that public access to the larger impoundments must be limited to beyond 765 meters to assure no exposure above any of the AGCs. As noted previously, it is possible that the maximum annual impacts and the distance factors in Tables 6.20 and 6.21, respectively, for methanol and heavy naphtha are overstated due to the inability to maintain their relatively larger short-term emissions over a year. However, the results in Table 6.21 and Figure 6.7 also indicate that, even without these pollutants, the AGC exceedences would still require a large distance from the impoundment to preclude public exposure. In addition, the elimination of heavy naphtha as a gelling agent would not considerably reduce the distance to AGC exceedences in this case. Furthermore, the elimination of glutaraldehyde as a bactericide would not necessarily lead to a lesser distance to an exceedance since the Department has not modeled certain other bactericides in the list from industry due to a lack of necessary information to determine both their emission rates and ambient thresholds.

These latter considerations raise the issue of advisability of allowing flowback water to sit in these large offsite impoundments for a year or more without any control or mitigation measures, as indicated desirable by certain industry operators. In fact, the SEQRA process requires the imposition of mitigation measures to the maximum extent practicable to address any potential expected adverse impacts. Measures to limit both short-term impacts and long-term emissions (as a means to reduce impacts) from these centralized impoundments can be readily devised, and it is recommended that such measures be implemented in lieu of attempting to "fence in" adverse impacts, especially on a long term basis. As discussed, some of the emission rates used in the modeling can be argued to be overly conservative due to previously noted factors, such as the retention times of the chemicals in the impoundments over the long term. However, some of these considerations are balanced by the fact that the Department's analysis has been limited to a handful of the many chemicals proposed for use in the additives and, furthermore, has relied on in-water concentrations which can vary to a certain extent from site to site. Thus, it is only prudent to apply readily available mitigation measures to minimize air emissions from these impoundments. Lastly, it should be recognized that the predicted impacts presented are dependent on the area of the impoundment; any significant increase in these dimensions could require further assessments.

The suggested mitigation measures are independent of any other regulatory requirements that might be relevant. For example, due to the fact that many of these chemicals are defined as hazardous air pollutants (HAPs), DEC and EPA air regulations might dictate certain other requirements which have to be met if these impoundments were determined to be a major source of HAPs. Since the emissions of methanol and heavy naphtha (which contains HAPs) from the centralized impoundment were relatively large, preliminary calculations were made assuming ten wells would be drilled and the flowback water emissions from these would be all emitted into the atmosphere over a year's period. These calculations indicate that the major source threshold for both individual HAPs (10 tons/year) and combined HAPs (25tons/year) could be exceeded. Thus, it might be necessary to review these emissions for each proposed centralized impoundment using the site specific set of additives and their corresponding emissions.

6.5.2.5 Conclusions

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad at a typical site over the Marcellus Shale. The analysis relied on recommended EPA and DEC modeling procedures and input data assumptions. Due to the extensive area of the Marcellus Shale and other low-permeability gas reservoirs in New York, certain assumptions and simplifications had to be made in order to properly simulate the impacts from a "typical" site such that the results would be generally applicable. At the same time, an adequate meteorological data base from a number of locations was used to assure proper representation of the potential well sites in the whole of the Marcellus Shale area in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were provided by industry and independently verified by DEC staff. The emission information was provided for the gas drilling, completion and production phases of expected operations. On the other hand, emissions of potential additive chemicals from the flowback water impoundments, which were proposed by industry as one means for reuse of water, were not provided by industry or an ICF report to NYSERDA. Thus, emission rates were developed by DEC using an EPA emission model for a set of representative chemicals which were determined to likely control the potential worst case impacts, using information provided by the hydraulic fracturing completion operators. The information included the compounds used for various purposes in the hydraulic fracturing process and the relative content of the various chemicals by percent weight. The resultant calculated emission rates were shared with industry for their input and comment prior to the modeling.

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for DEC-defined threshold levels for non-criteria pollutants. Limitations on simultaneous operations of the various equipment at both onsite and offsite operations for a multi-well pad were included in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

Initial modeling results indicated compliance with the majority of ambient thresholds, but also identified certain pollutants which were projected to be exceeded due to specific sources emission rates and stack parameters provided in the industry report. It was noted that many of these exceedences related to the very short stacks and associated structure downwash effects for the engines and compressors used in the various phases of operations. Thus, limited additional modeling was undertaken to determine whether simple adjustments to the stack height might alleviate the exceedences as one mitigation measure which could be implemented. For the flowback water impoundments, the modeling indicated exceedences of New York 1 hour and annual guideline concentrations for few of the additive chemicals for both the onsite and centralized impoundments. For the on-site impoundments, a practical mitigation measure would be the placement of a fence to preclude public exposure to potential exceedences at a relatively short distance away from the well pad.

Table 6.11 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → / Source ↘	SO_2	NO_2	PM10 &PM2.5	CO	Non-criteria combustion emissions	H_2S and other gas constituents
Engines for drilling	✔	✔	✔	✔	□	
Compressors for drilling	✔	✔	✔	✔	✔	
Engines for hydraulic fracturing	✔	✔	✔	✔	✔	
line heaters	✔	✔	✔	✔	✔	
offsite compressors	✔	✔	✔	✔	✔	
flowback gas flaring	✔	✔	✔	✔	✔	
gas venting						✔
mud-gas separator						✔
glycol dehydrator					✔	✔

Table 6.12 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Years of Meteorology	Latitude/Longitude coordinates
Albany	2007-08	42.747/73.799
Syracuse	2007-08	43.111/76.104
Binghamton	2007-08	42.207/75.980
Jamestown	2001-02	42.153/79.254
Buffalo	2006-07	42.940/78.736
Montgomery	2005-06	41.509/74.266

Table 6. 13 - Selected Representative Pollutants in Hydraulic Fracturing Water Compounds[47]

Pollutant	CAS Number	Purpose-Agent	Agent's % in Water	Max % in Compound	Max Conc. in Water (g/m^3)	SGC (µg/m^3)	AGC (µg/m^3)
acrylamide	79-06-1	friction reducer	0.1%	1%	10	3.0*	0.00077
benzene	71-43-2	corrosion inhibitor	0.001%	0.0001%	0.00001	1300	0.13
xylene	1330-20-7	corrosion inhibitor	0.001%	30%	3	4300	100
ethylene glycol	107-21-1	clay/iron control crosslinker, breaker scale inhibitor	0.06%	30%	180	10,000	400
propylene glycol (Propanediol-1,2)	57-55-6	breaker surfactant	0.1%	50%	500	55,000	2000
diammonium peroxidisulphate	7727-54-0	breaker	0.01%	100%	100	10*	0.28
hydrochloric acid	7647-01-0	acid	0.11%	35%	385	2100	20
glutaraldehyde	111-30-8	bactericide	0.03%	30%	90	20	0.08
monoethanolamine (ethanoamine)	141-43-5	crosslinker corrosion inhibitor	0.006%	30%	18	1500	18
propargyl alcohol	107-19-7	corrosion inhibitor	0.001%	15%	1.5	230*	5.5
methanol	67-56-1	surfactant/crosslinker scale inhibitor	0.12%	82%	984	33,000	4000
formaldehyde	50-00-1	corrosion inhibitor	0.001%	5%	0.5	30	.06
heavy naphtha	64742-48-9	gelling agent	0.05%	55%	275	4300*	700*

[47] SGC or AGC with * notation were not in DEC's AG-1 tables and were developed by DEC's Toxics Assessment Section with NYSDOH assistance.

Table 6. 14 - National Ambient Air Quality Standards (NAAQS), PSD increments and Significant Impact Levels (SILs) for Criteria Pollutants (µg/m3).

Pollutant	1 hour	3 hour	8 hour	24 hour	annual
SO_2 NAAQS PSD Increment SILs		1300 512 25		365 91 5	80 20 1
PM10 NAAQS PSD Increment SILs				150 30 5	50 17 1
PM2.5 NAAQS SILs[48]				35 5.0/1.2	15 0.3
NO_2 NAAQS PSD Increment SILs					100 25 1.0
CO NAAQS SILs	40,000 2000		10,000 500		

[48] The PM2.5 standards reflect the 3 year averages with the 24 hour standard beingcalculated as the 98th percentile value. In addition, there are currently no SILs defined by EPA,but the values tabulated are those from DEC's CP-33 (5 ug/m^3 value) and recommended to EPAby Northeast States for Coordinated Air Use Management (NESCAUM).

Table 6. 15 - Maximum Background Concentrations from DEC Monitor Sites

Pollutant	Monitor Sites	Maximum Observed Values for 2005-2007 ($\mu g/m^3$)
SO_2	**Elmira* and Belleayre**	**3 hour-125 24 hour- 37 Annual- 8**
NO_2	**Amherst**	**Annual- 26**
PM10**	**Newburg* and Belleayre**	**24 hour- 49 Annual-13**
PM2.5	**Newburg* and Pinnacle State Park**	**24 hour- 30 Annual-11 (3 year averages per NAAQS)**
CO	**Loudonville**	**1 hour-1714 8 hour-1112**

Note: * Denotes the site with the higher numbers.

**** For PM10, data from years 2002-4 was used.**

Table 6.16 - Maximum Impacts of Criteria Pollutant for Each Meteorological Data Set

Met Year & Location	SO_2 3hour	SO_2 24 hour	SO_2 Annual	PM10 24 hour	PM10 Annual	PM2.5* 24hour	PM2.5* Annual	CO 1 hour	CO 8 hour	NO_2 Annual
Albany 2007	15.4	13.3	3.1	459	2.7	355	2.7	9270	8209	57.9
2008	15.3	13.2	2.9		2.4		2.4	9262	8298	51.0
Syracuse 2007	15.9	12.6	2.8		2.7		2.7	8631	7849	57.1
2008	15.8	14.3	2.7		2.7		2.7	8626	7774	55.4
Binghamton 2007	18.5	13.4	2.3		2.1		2.1	10122	8751	45.5
2008	18.6	15.4	1.9		1.8		1.8	9970	8758	37.6
Jamestown 2001	16.7	14.0	2.4		2.1		2.1	8874	8193	46.4
2002	16.8	14.4	2.7		2.3		2.3	8765	8199	50.9
Buffalo 2006	16.6	15.7	3.2		2.9		2.9	9023	8067	63.2
2007	16.9	14.4	3.1		2.8		2.8	8910	8270	60.8
Montgomery 2005	17.4	11.6	1.9		1.8		1.8	9362	8226	38.4
2006	14.4	14.0	2.2		2.0		2.0	9529	8301	41.9
Maximum	18.6	15.7	3.2		2.9		2.9	10122	8758	63.2
Impact at 500m	0.3	0.3	0.05	7.1	.11	5.0	.11	480	253	2.5

Note: 24 hour PM2.5 values are the 8th highest impact per the standard.

Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards

Pollutant and Averaging Time	Maximum Impact (μg/m³)	SIL*	Worst Case Background Level (μg/m³)	Total (μg/m³)	NAAQS (μg/m³)	Increment Impact** (μg/m³)	PSD Increment (μg/m³)
SO_2 - 3 hour	18.6	25	125	143.6	1300	18.6	512
SO_2 - 24 hour	15.7	5	37	52.7	365	15.7	91
SO_2 - Annual	3.2	1	8	11.2	80	3.2	20
PM10 - 24 hour	459	5	49	508	150	6.5**	30
PM10 - Annual	2.9	1	13	15.9	50	2.9	17
PM2.5 - 24 hour	355	1.2/5.0	30	385	35	NA	None
PM2.5 - Annual	2.9	0.3	11	13.9	15	NA	None
NO_2 - Annual	63.2	1.0	26	89.2	100	5.6**	25
CO - 1 hour	10,122	2000	1714	11,836	40,000	NA	None
CO - 8 hour	8758	500	1112	9870	10,000	NA	None

Notes: *** SILs for PM2.5 are only used to determine the need for a cumulative analysis or for an EIS per CP-33 since currently there are no EPA promulgated levels.**
**** Impacts from the compressor plus the line heater only for PSD increment comparisons were recalculated for NO_2 and PM10 24 hour cases. NA means not applicable.**

Table 6.18 - Maximum Impacts of Non-criteria Pollutants and Comparisons to SGC/AGC and NewYork state AAQS

Pollutant	Total Venting Emissions Rate (g/s)	Impacts from all Venting Sources (μg/m^3) Max 1hour	SGC	All Combustion Sources and Dehydrator Impacts(μg/m^3) Max 1 hour	SGC	Max Annual	AGC
Benzene	**0.218**	**140**	**1300**	**13.2**	**1300**	**0.90** **0.10**	**0.13**
Xylene	**0.60**	**365**	**4300**	**NA****	**4300**	**NA**	**100**
Toluene	**0.78**	**500**	**37,000**	**NA**	**37,000**	**NA**	**5000**
Hexane	**9.18**	**5888**	**43,000**				
H_2S	**0.096**	**61.5** **12.1**	**14***				
Formaldehyde				**4.4**	**30**	**0.20** **0.04**	**0.06**
Acetaldehyde				**NA**	**4500**	**0.06**	**0.45**
Naphthalene				**NA**	**7900**	**NA**	**3.0**
Propylene				**NA**	**21,000**	**NA**	**3000**

NOTE: * denotes the New York State 1 hour standard for H_2S.

** NA denotes not analyzed by modeling, but it is concluded that the SGCs and AGCs will be met (see text).

Table 6.19 - Impoundment Normalized (1 g/s) Area Source Impacts

		Onsite 15 x 45 m		Offsite 150 x 150 m	
Site	**Year**	**1 hour**	**Annual**	**1 hour**	**Annual**
Albany	**2007**	**54484**	**2117**	**4125**	**245**
	2008	**56057**	**2291**	**4085**	**264**
Syracuse	**2007**	**80184**	**2624**	**5329**	**342**
	2008	**77135**	**2905**	**5322**	**354**
Binghamton	**2007**	**44640**	**1791**	**3195**	**225**
	2008	**46961**	**1991**	**3207**	**229**
Jamestown	**2001**	**65592**	**2363**	**6942**	**268**
	2002	**73725**	**2470**	**6988**	**279**
Buffalo	**2006**	**49820**	**2835**	**3376**	**329**
	2007	**47759**	**3057**	**3398**	**355**
Montgomery	**2005**	**52434**	**2579**	**4216**	**303**
	2006	**53075**	**2553**	**4206**	**298**
Max		**80184**	**3057**	**6988**	**355**

Table 6.20 - Comparison of Maximum Impoundment Fluid Additives Impacts to Ambient Thresholds

Pollutant	Emission Rate (g/s) Central / Onsite	Max 1hour Impact($\mu g/m^3$) Central/Onsite	SGC $\mu g/m^3$	Max 1 hour to SGC ratio Central/Onsite	Max annual Impact($\mu g/m^3$) Central /Onsite	AGC $\mu g/m^3$	Max annual to AGC ratio Central/Onsite
acrylamide	1.24E-5 / 4.48E-7	8.6E-2 / 3.6E-2	3.0	0.03 / 0.01	4.4E-3 / 1.4E-3	0.00077	5.7 / 1.8
benzene	6.10E-7 / 1.19E-8	4.3E-3 / 9.5E-4	1300	3E-6 / 1E-6	2.2E-4 / 3.6E-5	0.13	0.002 / 0.0003
xylene	1.94E-1 / 3.78E-3	1.4E+3 / 3.0E+2	4300	0.3 / 0.07	6.9E+1 / 1.2E+1	100	0.7 / 0.1
ethylene glycol	1.66E-3 / 6.00E-5	1.2E+1 / 4.8	10,000	0.001 / 5E-4	5.9E-1 / 1.8E-1	400	0.001 / 0.0005
propylene glycol (Propanediol-1,2)	3.15 / 1.06E-1	2.2E+4 / 8.5E+3	55,000	0.4 / 0.15	1.1E+3 / 3.2E+2	2000	0.6 / 0.2
diammonium peroxidisulphate	9.45E-5 / 3.43E-6	6.6E-1 / 2.8E-1	10	0.07 / 0.03	3.4E-2 / 1.1E-2	0.28	0.1 / 0.04
hydrochloric acid	1.34E-3 / 4.85E-5	9.34 /3.9	2100	0.004 / 0.002	4.8E-1 / 1.5E-1	20	0.02 / 0.01
glutaraldehyde (pentaredial)	1.25E-2 / 4.54E-4	8.8E+1 / 3.6E+1	20	4.4 / 1.8	4.4 / 1.4	0.08	55.6 / 17.3
monoethanolamine (ethanoamine)	2.69E-2 / 9.58E-4	1.9E+2 / 7.7E+1	1500	0.13 / 0.05	9.5 / 2.9	18	0.5 / 0.2
propargyl alcohol	8.64E-3 / 2.95E-4	6.0E+1 / 2.4E+1	230	0.3 / 0.1	3.1 / 9.0E-1	5.5	0.6 / 0.2
methanol	2.42E+1/ 7.15E-1	1.7E+5 / 5.7E+4	33,000	5.1 / 1.7	8.6E+3 / 2.2E+3	4000	2.1 / 0.6
formaldehyde	1.05E-3 / 3.74E-5	7.34 /3.0	30	0.2 / 0.1	3.7E-1 / 1.1E-1	0.06	6.2 / 1.9
heavy naphtha	1.5E+1 / 4.49E-1	1.1E+5 /3.6E+4	4300	24.3 / 8.4	5.3E+3 / 1.4E+3	700	7.6 / 2.0

Table 6.21 - Distances from Impoundments Necessary to Meet SGCs and AGCs

Impoundment and Averaging	Pollutant and "Reduction Factor"	Distance (in meters)
On-site SGCs	Heavy Naphtha – 8 Methanol & Glutaraldehyde - 2	140 <15
On-site AGCs	Glutaraldehyde – 17 Acrylamide, formaldehyde & heavy naphtha - 2	100 <15
Off-site SGCs	Heavy Naphtha - 25 Methanol & Glutaraldehyde - 5	> 1000 340
Off-site AGCs	Glutaraldehyde - 55 Acrylamide, formaldehyde & heavy naphtha - 7 Methanol - 2	765 165 30

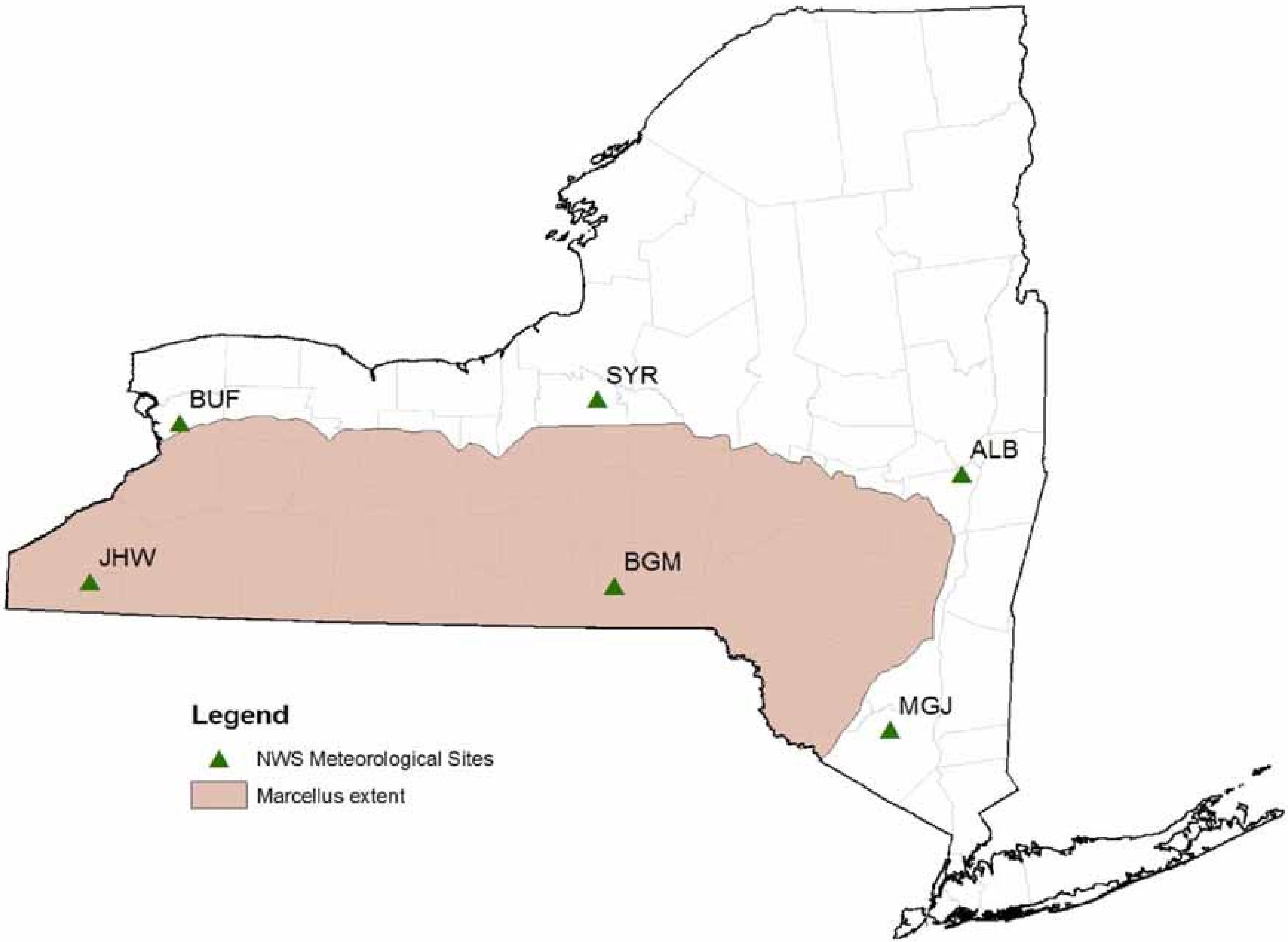


Figure 6.4 - Marcellus Shale Extent

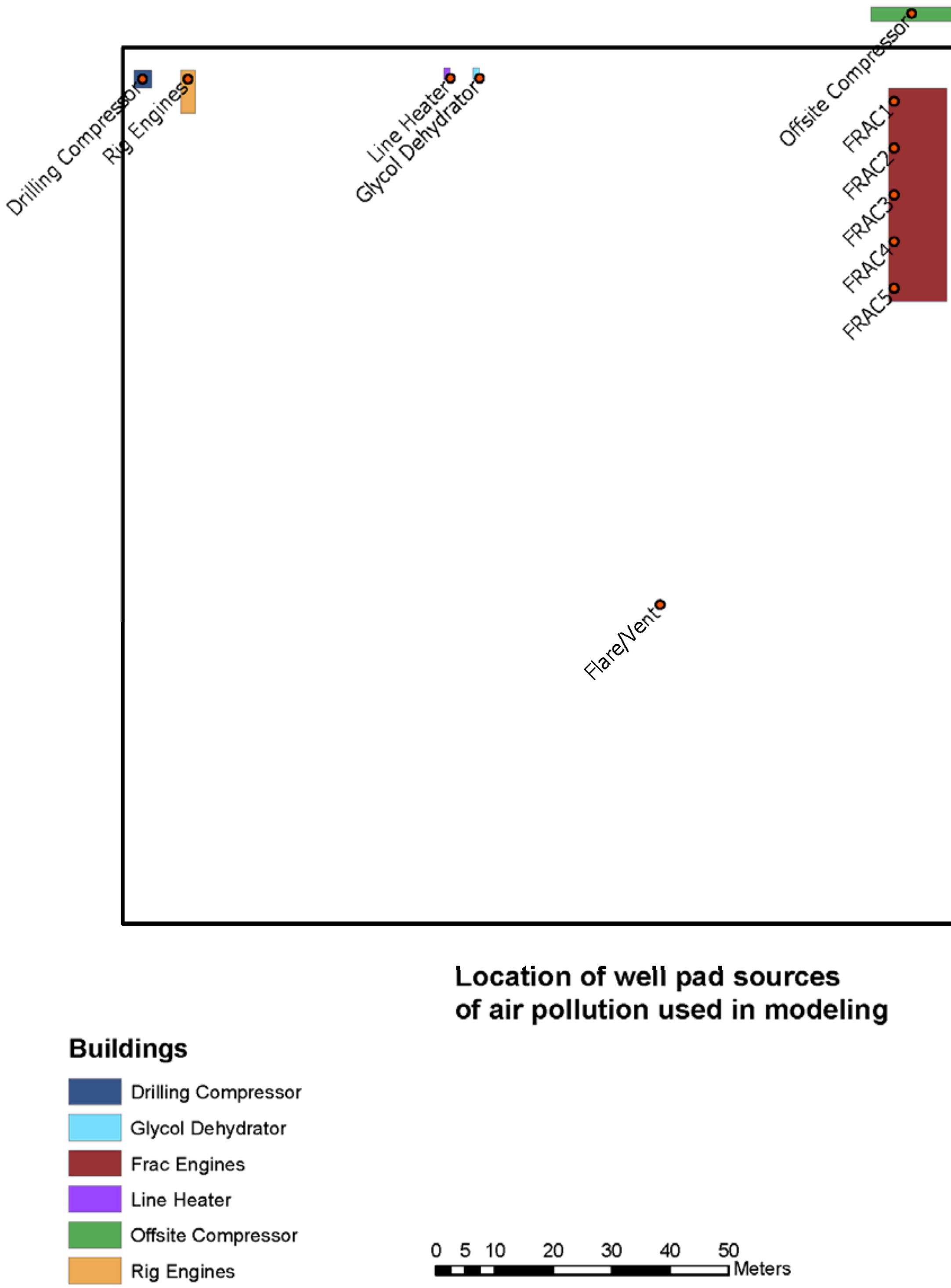


Figure 6.5 - Location of Well Pad Sources of Air Pollution Used in Modeling

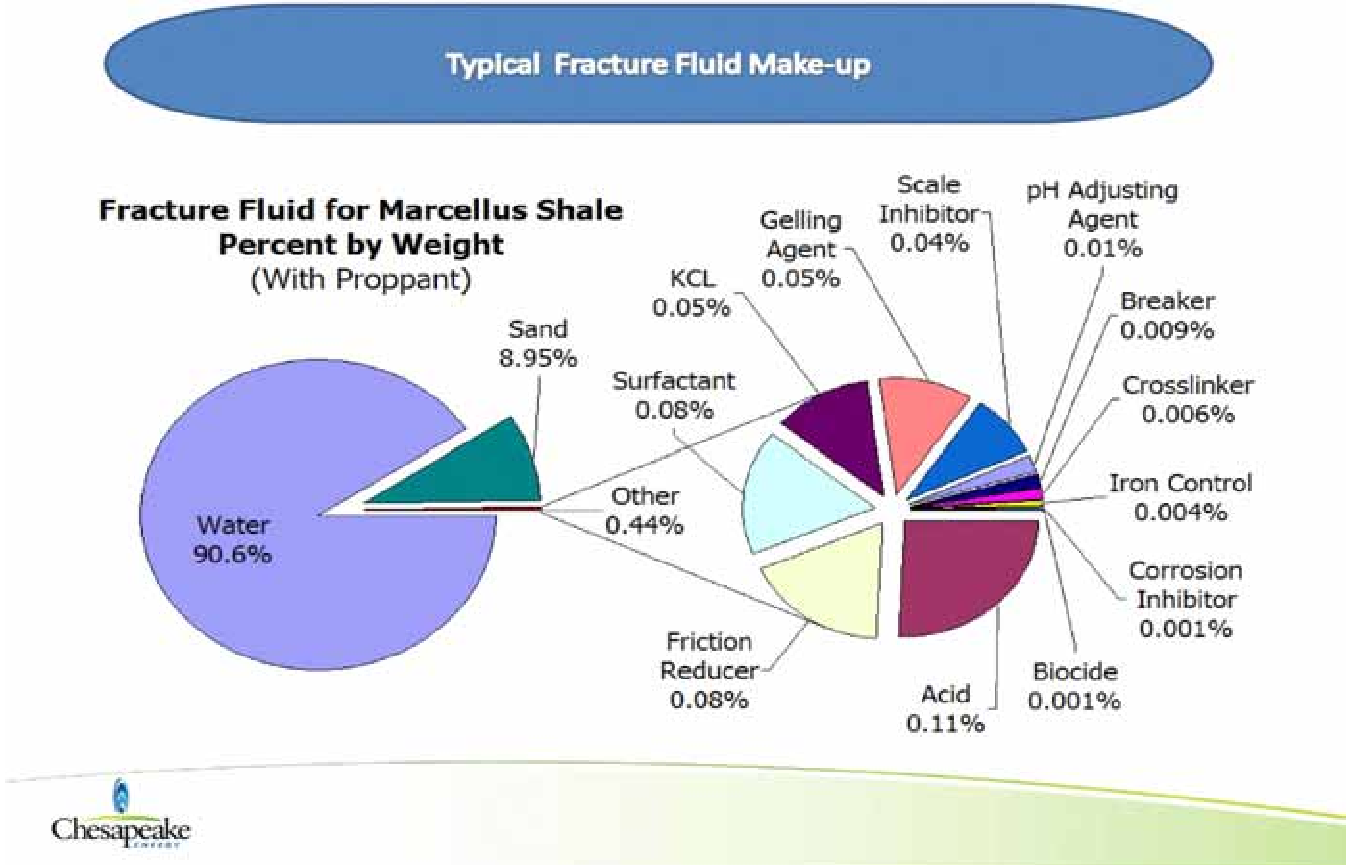


Figure 6.6 - Percent by Weight of Hydraulic Fracturing Additive Compounds

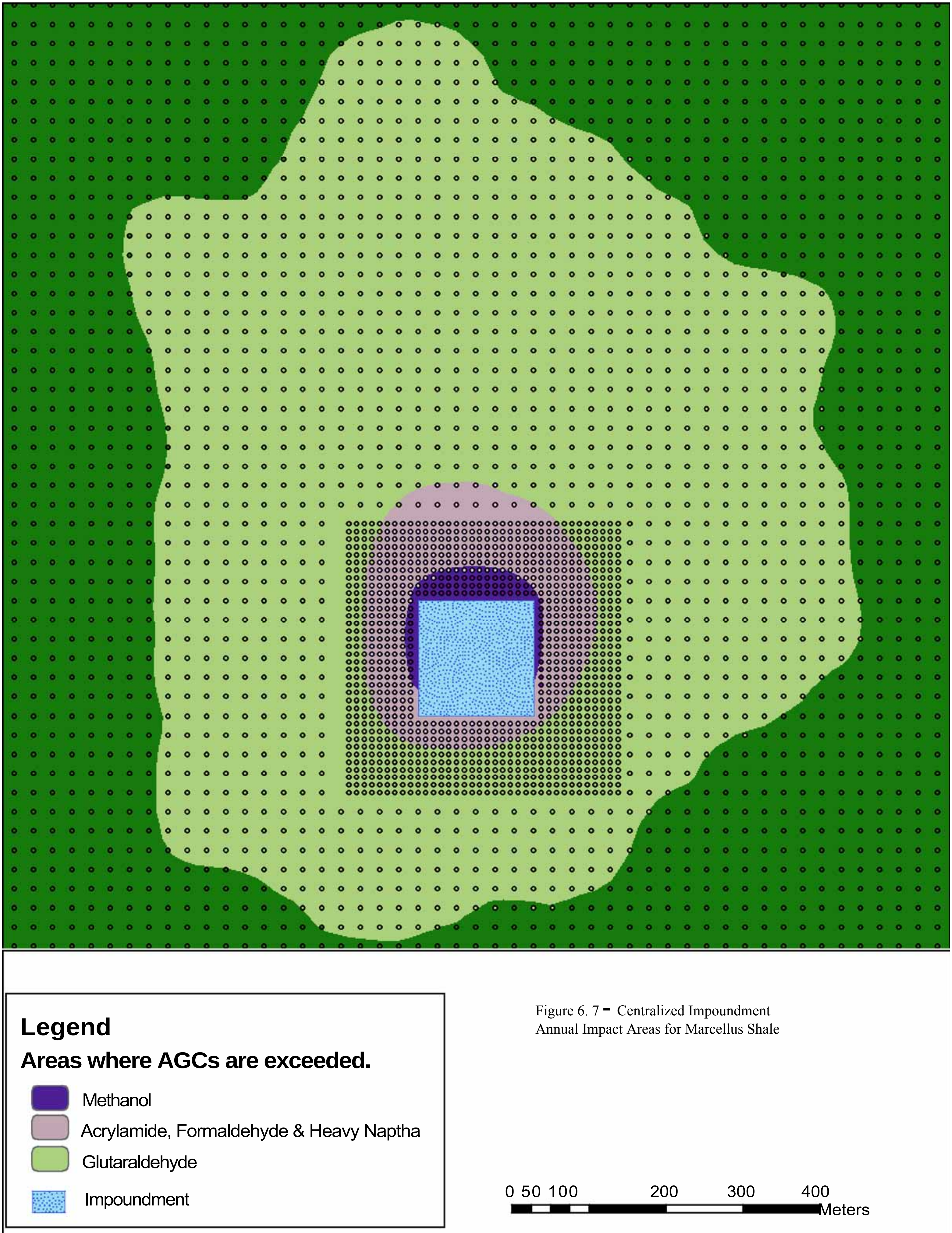


Figure 6. 7 - Centralized Impoundment
Annual Impact Areas for Marcellus Shale

6.6 Greenhouse Gas Emissions

On July 15, 2009, the Department's Office of Air, Energy and Climate issued its *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*.[49] The policy reflected in the guide is used by DEC staff in reviewing an environmental impact statement (EIS) when DEC is the lead agency under the State Environmental Quality Review Act (SEQR) and energy use or greenhouse gas (GHG) emissions have been identified as significant in a positive declaration, or as a result of scoping, and, therefore, are required to be discussed in an EIS. Following is an assessment of potential GHG emissions for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing.

SEQR requires that lead agencies identify and assess adverse environmental impacts, and then mitigate or reduce such impacts to the extent they are found to be significant. Consistent with this requirement, SEQR can be used to identify and assess climate change impacts, as well as the steps to minimize the emissions of GHGs that cause climate change. Many measures that will minimize emissions of GHGs will also advance other long-established State policy goals, such as energy efficiency and conservation; the use of renewable energy technologies; waste reduction and recycling; and smart and sustainable economic growth. The *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement* is not the only State policy or initiative to promote these goals; instead, it furthers these goals by providing for consideration of energy conservation and GHG emissions within EIS reviews.[50]

The goal of this analysis is to characterize and present an estimate of total annual emissions of carbon dioxide (CO_2), and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons, for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. In addition, the major contributors of GHGs are to be identified and potential mitigation measures offered.

---

[49] Hhttp://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf

[50] Hhttp://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf

6.6.1 Greenhouse Gases

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapor is the most important greenhouse gas, and CO_2 is the second-most important one.[51] Human activities result in emissions of four principal greenhouse gases: CO_2, methane (CH_4), nitrous oxide (N_2O) and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time. Many human activities contribute greenhouse gases to the atmosphere.[52] Whenever fossil fuel (coal, oil or gas) burns, CO_2 is released to the air. Other processes generate CH_4, N_2O and halocarbons and other greenhouse gases that are less abundant than CO_2, but even better at retaining heat.[53]

6.6.2 Emissions from Oil and Gas Operations

Greenhouse gas emissions from oil and gas operations are typically categorized into 1) vented emissions, 2) combustion emissions and 3) fugitive emissions. Below is a description of each type of emission. For the noted emission types, no distinction is made between direct and indirect emissions in this analysis. Further, this GHG discussion is focused on CO_2 and CH_4 emissions as these are the most prevalent GHGs emitted from oil and gas industry operations, including expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. Virtually all companies within the industry would be expected to have emissions of CO_2 - and, to a lesser extent, CH_4 and N_2O - since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced in varying quantities, from oil and gas wells. Because the quantities of N_2O produced through combustion are quite small

[51] IPCC, 2007: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 98. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf

[52] IPCC, 2007: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Pg. 100. [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf

[53] http://www.dec.ny.gov/energy/44992.html

compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[54]

6.6.2.1 Vented Emissions

Vented sources are defined as releases resulting from normal operations. Vented emissions of CH_4 can result from the venting of natural gas encountered during drilling operations, flow from the flare stack during the initial stage of flowback, pneumatic device vents, dehydrator operation, and compressor start-ups and blowdowns. Oil and natural gas operations are the largest human-made source of CH_4 emissions in the United States and the second largest human-made source of CH_4 emissions globally. Given methane's role as both a potent greenhouse gas and clean energy source, reducing these emissions can have significant environmental and economic benefits. Efforts to reduce CH_4 emissions not only conserve natural gas resources but also generate additional revenues, increase operational efficiency, and make positive contributions to the global environment.[55]

6.6.2.2 Combustion Emissions

Combustion emissions can result from stationary sources (e.g., engines for drilling, hydraulic fracturing and natural gas compression), mobile sources and flares. Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of hydrocarbon combustion. Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete combustion of the fuel gas, which is emitted as unburned CH_4. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions.[56]

6.6.2.3 Fugitive Emissions

Fugitive emissions are defined as unintentional gas leaks to the atmosphere and pose several challenges for quantification since they are typically invisible, odorless and not audible, and

---

[54] International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003., p. 5-2.

[55] http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf

[56] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. p 4-1.

often go unnoticed. Examples of fugitive emissions include CH_4 leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies.[57] In the context of GHG emissions, fugitive sources within the upstream segment of the oil and gas industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant.[58]

6.6.3 Emissions Source Characterization

Emissions of CO_2 and CH_4 occur at many stages of the drilling, completion and production phases, and can be dependent upon technologies applied and practices employed. Considerable research – sponsored by the American Petroleum Institute (API), the Gas Research Institute (GRI) and the United States Environmental Protection Agency (USEPA) – has been directed towards developing relatively robust emissions estimates at the national level.[59] The analytical techniques and emissions factors, and mitigation measures, developed by the these agencies were used to evaluate GHG emissions from activities necessary for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing.

In 2009, the New York State Energy Research and Development Authority (NYSERDA) contracted ICF International (ICF) to assist with supporting studies for the development of the SGEIS. ICF's work included preparation of a technical analysis of potential impacts to air in the form of a report finalized in August 2009.[60] The report, which includes a discussion on GHGs,

[57] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, *Task 2 – Technical Analysis of Potential Impacts to Air*, August 2009, NYSERDA Agreement No. 9679. p. 21.

[58] International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003., p. 5-6

[59] Center for Climate Strategies prepared for New Mexico Environment Department, November 2006., *Appendix D New Mexico Greenhouse Gas Inventory and Reference Case Projections, 1990-2020*., pp. D-35.

[60] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, *Task 2 – Technical Analysis of Potential Impacts to Air*, August 2009, NYSERDA Agreement No. 9679.

provided the basis for the following in-depth analysis of potential GHGs from the subject activity. ICF's referenced study identifies drilling, completion and production operations and equipment that contribute to GHG emission and provides corresponding emission rates, and this information facilitated the following analysis by identifying system components on an operational basis. As such, wellsite operations considered in the SGEIS were divided into the following phases for this GHG analysis.

- Drilling Rig Mobilization, Site Preparation and Demobilization
- Completion Rig Mobilization and Demobilization
- Well Drilling
- Well Completion (includes hydraulic fracturing and flowback)
- Well Production

Transport of materials and equipment is integral component of the oil and gas industry. Simply stated, a well cannot be drilled, completed or produced without GHGs being emitted from mobile sources. NTC Consultants (NTC), which was also contracted by NYSERDA in support of SGEIS preparation, performed an impact analysis on community character of horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability gas reservoirs. NTC determined that the subject activity would require significantly more trucking than was addressed by the 1992 GEIS. NTC estimated required truck trips per well for the noted phases requiring transportation as follows:[61]

<u>Drilling Rig Mobilization, Site Preparation and Demobilization</u>	
Drill Pad and Road Construction Equipment	10 – 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 – 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 – 50 Truckloads
<u>Completion Rig Mobilization and Demobilization</u>	
Completion Rig	15 Truckloads

61 NTC Consultants. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, September 2009.

<u>Well Completion</u>	
Completion Fluid and Materials	10 - 20 Truckloads
Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads
<u>Well Production</u>	
Production Equipment	5 – 10 Truckloads

In this analysis, two transportation scenarios were developed and evaluated for the sourcing of equipment and materials, and the disposal of wastes (i.e. frac flowback waters, production brine). For simplification, any subsequent reference in this analysis to "sourcing" includes both incoming and outgoing equipment and materials to and from the wellsite or wellpad. Both transportation scenarios incorporated NTC's estimates for truck trips, including the ranges of needed truckloads. An in-state sourcing option assuming a round-trip mileage of twenty miles (e.g., local) and an out-of-state sourcing option assuming a round-trip mileage of four hundred miles (e.g., originating from central Pennsylvania) were used to determine total vehicle miles traveled (VMT) associated with site preparation and rig mobilizations, well completion and well production activities. As further discussed below, when actual or estimated fuel use data was not available, VMT formed the basis for estimating CO_2 emissions. However, to illustrate the impact of out-of-state sourcing compared to in-state sourcing on GHG emissions, and to present a worst-case scenario, an all-or-nothing approach was used in that all materials, equipment and disposal of production brine were represented as wholly sourced from either in-state or out-of-state. Actual operations at a single well or multiple well pad may involve a combination of sourcing from both in-state and out-of-state. Nevertheless, it was demonstrated through this analysis that in-state sourcing is the preferred option with respect to minimizing GHG emissions.

In addition to accounting for the two sourcing scenarios described above, two distinct types of well projects were evaluated for GHG emissions as follows.

- Single-Well Project
- Ten-Well Pad

In calculating VMT for rig and equipment mobilizations for each of the project types noted above, it was assumed that all work involving the same activity would be finished before commencing a different activity. In other words, the site would be prepared and the drilling rig mobilized, then all wells (i.e., one or ten) would be drilled, followed by the completion of all wells (i.e., one or ten) and subsequent production of all wells (i.e., one or ten). A number of operators have indicated to the Department that activities will be conducted sequentially, whenever possible, to realize the greatest efficiency but the actual order of work events and number of wells on a given pad may vary.

Stationary engines and equipment emit CO_2 and/or CH_4 during drilling and completion operations. However, most are not typically operating at their full load every hour of each day while on location. For example, certain engines may be shut down completely or operating at a very low load during bit trips, geophysical logging or the running of casing strings. Consequently, for the purpose of this analysis and as noted in Table 6.13 it was assumed that engines and equipment for drilling and completion operations generally operate at full load for 50% of their time on location. Exceptions to this included engines and equipment used for hydraulic fracturing and flaring operations. Instead of relying on an assumed time frame for operation for the many engines that drive the high-pressure high volume pumps used for hydraulic fracturing, an average of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used.[62] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.13 - Assumed Drilling & Completion Time Frames Per Well

Operation	Estimated Duration (days / hrs.)	Full Load Operational Duration for Related Equipment (days / hrs.)
Well Drilling	28 / 336	14 / 168
Completion	3 / 72 (frac) 2 / 48 (rig)	3 / 72 (frac) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

[62] ALL Consulting, *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* August 2009., Table 11, p. 10.

Stationary engines and equipment also emit CO_2 and/or CH_4 during production operations. In contrast to drilling and completion operations, production equipment generally operates around the clock (i.e., 8,760 hours per year) except for scheduled or intermittent shutdowns.

6.6.4 Emission Rates

The primary reference for emission rates for stationary production equipment considered in this analysis is the GRI's *Methane Emissions from the Natural Gas Industry*. Table GHG-1 "Emission Rates for Well Pad" in Appendix 19, Part A shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well production operations. Table GHG-1 was adapted from an analysis of potential impacts to air performed in 2009 by ICF International under contract to NYSERDA. GHG emission rates for flaring during the completion phase were also obtained from the ICF International study. The emission factors in the table are typically listed in units of pounds emitted per hour for each piece of equipment. The emissions rates specified in the table were used to determine the annual emissions in tons for each stationary source, except for engines used for rig and hydraulic fracturing engines, using the below equation. The *Activity Factor* represents the number of pieces of equipment or occurrences.

$$\boldsymbol{Emissions}\left(\frac{\boldsymbol{tons}}{\boldsymbol{yr.}}\right) = \boldsymbol{Emissions\ Factor}\left(\frac{\boldsymbol{lbs.}}{\boldsymbol{hr.}}\right) \times \boldsymbol{Duration}(\boldsymbol{yr.}) \times \left(\frac{\boldsymbol{8,760\ hrs.}}{\boldsymbol{yr.}}\right) \times \left(\frac{\boldsymbol{1\ US\ short\ ton}}{\boldsymbol{2000\ lbs.}}\right) \times \textbf{Activity Factor}$$

A material balance approach based on fuel usage and fuel carbon analysis, assuming complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2), is the preferred technique for estimating CO_2 emissions from stationary combustion engines.[63] This approach was used for the engines required for conducting drilling and hydraulic fracturing operations. Actual fuel usage, such as the volume of fuel needed to perform hydraulic fracturing, was used where available to determine CO_2 emissions. For emission sources where actual fuel usage data was not available, estimates were made based on the type and use of the engines needed to perform the work. For GHG emission from mobile sources, such as trucks used to transport equipment and materials, VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile sources. A sample calculation showing this

---

[63] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005., p. 4-3.

methodology for determining combustion emissions (CO_2) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH_4 emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of ten million cubic feet per day. ICF International's calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wellsite operations. Transportation sources may include vehicles such as cars and trucks used for work-related personnel transport, as well as tanker trucks and flatbed trucks used to haul equipment and supplies. The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The USEPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH_4 and N_2O emissions from mobile sources is to assume that these emissions are negligible compared to CO_2.[64]

An alternative to using modeling software for determining CO_2 emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of estimated fuel usage. This methodology was used to calculate the tons of CO_2 emissions from

[64] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005., pp. 4-32, 4-33.

mobile sources related to the subject activity. A sample CO_2 emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO_2 emission estimates from transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. Table GHG-2 assumes that the same rig stays on location and drills both the vertical and lateral portions of a well.

As previously mentioned, because all activities are assumed to be performed sequentially requiring a single rig move, the GHG emissions presented in Table GHG-2 are representative of either a one-well project or ten-well pad. As shown in the table, approximately 14 to 17 tons of CO_2 emissions are expected from an in-state move of the drilling rig, including site preparation. For the out-of state scenario of drilling rig mobilization and demobilization, it is estimated that such a move, including site preparation, would result in 69 to 123 tons of CO_2 emissions. The calculated CO_2 emissions presented in the table illustrate the impact of sourcing equipment and materials from out-of-state (400-mile round trip per vehicle assumed) opposed to sourcing of materials and equipment in-state (20-mile round trip per vehicle assumed). Comparatively, using the aforementioned round-trip mileages of 20 and 400, approximately five to six times the amount of CO_2 emissions are generated during drilling rig mobilization, site preparation and demobilization if equipment is sourced from out-of-state compared to an in-state move. The calculated CO_2 emissions shown in this table and all other tables included in this analysis have been rounded up to the next whole number.

6.6.6 Completion Rig Mobilization and Demobilization

Table GHG-3 in Appendix 19, Part A includes CO_2 emission estimates for transporting the completion rig to and from the wellsite, considering an in-state (20-mile round trip per vehicle) and out-of-state (400-mile round trip per vehicle) move. As shown in the table, approximately one ton of CO_2 emissions may be generated from an in-state move of the completion rig. For the out-of-state scenario for rig mobilization and demobilization, it is estimated that such a move would result in 10 tons of CO_2 emissions. As with the transport of the drilling rig, the estimated CO_2 emissions shown in Table GHG-3 illustrate the impact of sourcing the completion equipment and materials from out-of-state, as opposed to sourcing of materials and equipment in-state.

6.6.7 Well Drilling

Well drilling activities include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for CO_2 emissions generated by these stationary sources. As shown in the table, approximately 94 tons of CO_2 emissions per well will be generated as a result of drilling operations.

6.6.8 Well Completion

Well completion activities include 1) transport of required equipment and materials to and from the site, 2) hydraulic fracturing of the well, 3) a flowback period, including flaring, to clean the well of frac fluid and excess sand used as the hydraulic fracturing proppant, 4) drilling out of hydraulic fracturing stage plugs and the running of production tubing by the completion rig and 5) site reclamation. Mobile and stationary engines, and equipment used during the aforementioned completion activities emit CO_2 and/or CH_4. Tables GHG-5 and GHG-6 in Appendix 19, Part A include estimates of individual and total emissions of CO_2 and CH_4 generated during the completion phase for a one-well project and a ten-well pad, respectively.

Similar to the above discussion regarding mobilization and demobilization of rigs, transport of equipment and materials, which results in CO_2 emissions, is necessary for completion of wells. Again, both in-state and out-of-state sourcing scenarios, including the ranges of truckloads, were developed for a one-well project and a ten-well pad, and evaluated for GHG emissions for the completion phase. The results of this evaluation are shown in Tables GHG-5 and GHG-6 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on VMT, which ultimately requires a determination of fuel usage. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-5, transportation related completion-phase emissions of CO_2 for a one-well project is estimated at 25 to 37 tons and 504 to 737 tons from in-state and out-of-state sourcing, respectively. For the ten-well pad (see Table GHG-6), transportation related completion-phase CO_2 emissions are estimated at 208 to 310 tons for in-state and 4,161 to 6,209 tons for out-of-state sourcing, respectively. The out-of-state sourcing scenarios are significantly higher than the in-state scenarios because of the number of truckloads required for the flowback water tanks, hauling of fresh water and the ultimate removal of flowback waters from the sites. This speaks to the benefits of in-state sourcing opposed to out-of-state sourcing with respect to potential CO_2 emissions generated for transportation during the completion phase.

Hydraulic fracturing operations require the use of many engines needed to drive the high-pressure high-volume pumps used for hydraulic fracturing (see multiple "Pump trucks" in the Photos Section of Chapter 6). As previously discussed and shown in Table GHG-5 in Appendix 19, Part A, an average (i.e., 29,000 gallons of diesel) of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used to calculate the estimated amount of CO_2 emitted during hydraulic fracturing. Tables GHG-5 and GHG-6 show that approximately 325 tons of CO_2 emissions per well will be generated as a result of hydraulic fracturing operations.

Subsequent to hydraulic fracturing in which fluids are pumped into the well, the direction of flow is reversed and flowback waters, including reservoir gas, are routed through separation equipment to remove excess sand, then through a line heater and finally through a separator to separate water and gas on route to the flare stack. Generally speaking, flares in the oil and gas industry are used to manage the disposal of hydrocarbons from routine operations, upsets, or emergencies via combustion.[65] However, only controlled combustion events will be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of three days was considered for this analysis although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. Once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas into the sales line.[66] As shown in Table GHG-5 in Appendix 19, Part A, approximately 576 tons of CO_2 and 4 tons of CH_4

[65] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-27.

[66] ALL Consulting, *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* August 2009.. p. 14.

emissions are generated per well during a three-day flaring operation for a ten million cubic foot per day flowrate. As mentioned above, the actual duration of flaring may be more or less. The CH_4 emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO_2 and CH_4 emissions rates using an average Marcellus gas composition.[67] The duration of flaring operations may be significantly shortened by using specialized gas recovery equipment, provided a gas sales line is in place at the time of commencing flowback from the well. Recovering the gas to a sales line, instead of flaring it, is called a "reduced emissions completion" (REC) or "green completion" and is further discussed in Section 7.6 as a possible mitigation measure, and in Appendix 25 (REC Executive Summary included by ICF for its work in support of preparation of the SGEIS).

The final work conducted during the completion phase consists of using a completion rig, possibly a coiled-tubing unit, to drill out the hydraulic fracturing stage plugs and run the production tubing in the well. Assuming a fuel consumption rate of 25 gallons per hour and an operating period of 24 hours, the rig engines needed to perform this work emit CO_2 at a rate of approximately 7 tons per well. After the completion rig is removed from the site, the area will be reworked and graded by earth-moving equipment, which adds another 6 tons of CO_2 emissions for either a one-well project or ten-well pad. Tables GHG-5 and GHG-6 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a one-well project and ten-well pad respectively.

6.6.9 Well Production

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. Consistent with the approach used to analyze GHG emissions from other phases of work, two transportation scenarios were developed and evaluated for the sourcing of equipment and materials. Both transportation scenarios incorporated NTC's estimates for truck trips including the ranges in numbers of needed

[67] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, *Task 2 – Technical Analysis of Potential Impacts to Air,* August 2009, NYSERDA Agreement No. 9679. p. 28.

truckloads. An in-state sourcing option assuming a round-trip mileage of twenty miles and an out-of-state sourcing option assuming a round-trip mileage of four hundred miles were used to determine total VMT associated with well production activities, including removal of produced brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant CO_2 emissions. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite results in CO_2emissions of approximately 0.1 ton for in-state sourcing and 3 to 6 tons for out-of-state sourcing, respectively.

Well production may require the removal of produced brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO_2 emissions. In-state and out-of-state disposal transportation scenarios were developed to determine CO_2 emissions from each scenario, and emission estimates are presented in Tables GHG-7, GHG-8, GHG-9 and GHG-10 in Appendix 19, Part A. Table GHG-7 presents CO_2 and CH_4 emissions for a one-well project for the period of production remaining in the first year after the single well is drilled and completed. For the purpose of this analysis, the duration of production for a one-well project in its first year was estimated at 329 days (i.e., 365 days minus 36 days to drill & complete). Table GHG-8 shows estimated annual emissions for a one-well project commencing in year two, and producing for a full year. Table GHG-9 presents CO_2 and CH_4 emissions for a ten-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 5 days (i.e., 365 days minus 360 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-10 shows estimated annual emissions for a ten-well project commencing in year two, and producing for a full year.

GHGs in the form of CO_2 and CH_4 are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH_4 emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine's internal combustion cycle results in CO_2 emissions while compression of the natural gas generates CH_4 fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.[68] The emission rates presented in Table GHG-1, Appendix 19, Part A "Emission Rates for Well Pad" were used to calculate estimated emissions of CO_2 and CH_4 for each stationary source for a one-well project and ten-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-7, GHG-8, GHG-9 and GHG-10 in Appendix 19, Part A. Based on the specified emissions rates for each piece of production equipment, the calculated annual GHG emissions presented in the Tables GHG-8 and GHG-10 show that the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH_4 emissions during the this phase, while operation of pneumatic device vents also generates vented CH_4 emissions. The amount of CH_4 vented in the compressor exhaust was not quantified in this analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for "about 7.9% of methane emissions from the natural gas industry."

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2) Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion (includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was analyzed for potential GHG emissions, with a focus on CO_2 and CH_4 emissions. The results of these phase-specific analyses for a one-well project and ten-well pad are detailed in Tables GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year

[68] EPA., Lessons Learned From Natural Gas Star Partners, *Reduced Methane Emissions from Compressor Rod Packing Systems*, 2006. http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

thereafter for each project type (i.e., one-well & ten-well) with consideration to both in-state and out-of-state sourcing of equipment and materials.

The goal of this review is to characterize and present an estimate of total annual emissions of CO_2, and other relative GHGs, as both short tons and CO_2e expressed in short tons for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing . To determine CO_2e, each greenhouse gas has been assigned a number or factor that reflects its global warming potential (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2 released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory. Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.[69] For example, Chesapeake Energy Corporation's July 2009 Fact Sheet on greenhouse gas emissions states that CO_2 has a GWP of 1 and CH_4 has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO_2e.[70] However, GWP factors are continually being updated, and for the purpose of this analysis as required by the Department's 2009 *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*, the 100-Year GWP factors provided in below Table 6.23 were used to determine total GHGs as CO_2e. Tables GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A include a summary of estimated CO_2 and CH_4 emissions from the various operational phases as both short tons and as CO_2e expressed in short tons.

[69] American Petroleum Institute., *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-5, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf

[70] Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

Table 6.14 - Global Warming Potential for Given Time Horizon[71]

Common Name	Chemical Formula	20-Year GWP	100-Year GWP	500-Year GWP
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.6

Table 6.24 is a summary of total estimated CO_2 and CH_4 emissions for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing, as both short tons and as CO_2e expressed in short tons. The below table includes emission estimates for the first full year in which drilling is commenced and subsequent producing years for each project type (i.e., one-well & ten-well) with consideration of both in-state and out-of-state sourcing of equipment and materials. While somewhat masked by the first-year data presented below for the one-well project, out-of-state sourcing (including disposal) in the first year of well activities significantly contributes to increased CO_2 emissions for initial development of both the one-well project and ten-well pad. Still, these activities generally represent one-time events of relatively short duration.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual emissions and thus production operations contribute relatively greater amounts of GHG emissions on a CO_2e basis than do the cumulative impacts of rig mobilizations, well drilling and well completion. As noted above, for the purpose of assessing GHG impacts, each ton of CH_4 emitted is equivalent to 25 tons of CO_2. Thus, because of its recurring nature, the importance of limiting CH_4 emissions throughout the production phase cannot be overstated. The last row of the Table 6.15 also includes estimated GHG emissions for ongoing annual production at the ten-well pad on a per well basis. The lower annual emissions per well at the ten-well pad compared to the emissions from annual production at a one-well project demonstrate economy of scale from a GHG perspective and supports the contention that multiple well pads are advantageous for many reasons, including limiting GHGs.

---

[71] Adapted from Forster, P., V. Ramaswamy, P. Artaxo, T. Berntsen, R. Betts, D.W. Fahey, J. Haywood, J. Lean, D.C. Lowe, G. Myhre, J. Nganga, R. Prinn, G. Raga, M. Schulz and R. Van Dorland, 2007: Changes in Atmospheric Constituents and in Radiative Forcing. *In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Adapted from Table 2.14. Chapter 2, p. 212. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf

Table 6.15 - Summary of Estimated Greenhouse Gas Emissions

	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[72]	Total Emissions from Proposed Activity CO_2e (tons)	
	In-state Sourcing	*Out-of-state Sourcing*			*In-state Sourcing*	*Out-of-state Sourcing*
Estimated First-Year Green House Gas Emissions from One-Well Project	6,604 – 6,619	7,175 – 7,465	226	5,650	12,254 – 12,269	12,825 – 13,115
Estimated Post First-Year Annual Green House Gas Emissions from One-Well Project	6,163	6,202	244	6,100	12,263	12,302
Estimated First-Year Green House Gas Emissions from Ten-Well Pad	10,505 – 10,610	14,524 – 16,629	60	1,500	12,005 – 12,110	16,024 – 18,129
Estimated Post First-Year Annual Green House Gas Emissions from Ten-Well Project	18,784 (1,878/well)	19,076 (1,908/well)	1,470 (147/well)	36,750 (3,675/well)	55,534 (5,553/well)	55,826 (5,583/well)

Significant uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.25, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the "Published emission factors" and "Engineering calculations" options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that will be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.[73]

- Incomplete, unclear or faulty definitions of emission sources
- Natural variability of the process that produces the emissions

[72] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

[73] American Petroleum Institute., *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-30, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf

- Models, or equations, used to quantify emissions for the process or quantity under consideration

Nevertheless, while the results of potential GHG emissions presented in above Table 6.24 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO_2 and CH_4 emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Section 7.6, is a discussion of possible mitigation measures geared toward reducing GHGs, with emphasis on CH_4.

Table 6.16 - Emission Estimation Approaches – General Considerations[74]

Types of Approaches	General Considerations
Published emission factors	· Accounts for average operations or conditions · Simple to apply · Requires understanding and proper application of measurement units and underlying standard conditions · Accuracy depends on the representativeness of the factor relative to the actual emission source · Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	· Tailored to equipment-specific parameters · Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions · Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures · Accuracy depends on adjustment to actual fuel composition used on-site · Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	· Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	· Accuracy depends on simplifying assumptions that may be contained within the computer model methods · May require detailed input data to properly characterize process conditions · May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	· Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources · Care should be taken when correcting to represent the applicable standard conditions · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous[a] monitoring of emissions or parameters[b] for calculating emissions	· Accounts for operational and source specific conditions · Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters · Instrumentation not available for all GHGs or applicable to all sources · Equipment, operating, and maintenance costs must be considered for monitoring equipment

Footnotes and Sources:
[a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions.
[b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.

[74] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-9, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf

6.7 Centralized Flowback Water Surface Impoundments

The potential use of large centralized surface impoundments to hold flowback water as part of dilution and reuse system is described in Section 5.12.2.1. The potential impacts associated with use of such impoundments that are identified in several sections above and are summarized here.

Use of centralized surface impoundments and flowback water pipelines as part of a flowback water dilution and reuse system has environmental benefits, including reduced demand for fresh water, reduced truck traffic and reduced need for flowback water treatment and disposal. However, any proposal for their use requires that the potential impacts be recognized and mitigated through proper design, construction, operation, closure and regulatory oversight.

- Potential soil, wetland, surface water and groundwater contamination from spills, leaks or other failure of the impoundment to effectively contain fluid. This includes problems associated with liner or construction defects, unstable ballast or operations-related liner damage.
- Potential soil, wetland, surface water and groundwater contamination from spills or leaks of hoses or pipes used to convey flowback water to or from the centralized surface impoundment.
- Potential for personal injury, property damage or natural resource damage similar to that from dam failure if a breach occurs.
- Transfer of invasive plant species by machinery and equipment used to remove vegetation and soil.
- Consumption by waterfowl and other wildlife of contaminated plant material on the inside slopes of the impoundment.
- Emission of Hazardous Air Pollutants (HAPs) which could exceed ambient air thresholds 1,000 meters (3,300 feet) from the impoundment and could cause the impoundment to qualify as a major source of HAPs.

6.8 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to make the radioactive material more accessible to human contact or to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale.) Radium-226 is the radionuclide of greatest concern from the Marcellus.

Detection of elevated levels (multiple times background) of NORM in oil and gas drill sites in the North Sea and U.S. Gulf Coast and mid-continent areas in the 1980s led to concerns about health impacts on drill site workers and the general public where exploration and production equipment and wastes were disposed or recycled. The U.S. Environmental Protection Agency (USEPA) measured values of radioactivity ranging from 9,000 picocuries per liter (pCi/l) for produced water to >100,000 pCi/g (picocuries per gram) for pipe and tank scale. The annual general public and occupational radiation dose limits vary above estimated background levels of 300-400 millirem (mrem), depending on the agency of origin. The annual dose limits range from several tens to 5,000 mrem among the Nuclear Regulatory Commission (NRC), U.S. Department of Energy (USDOE), and USEPA. Additional components to the NORM issue are: 1) NORM is commonly measured in concentration units, either pCi/l or pCi/g, while health standards for all types of ionizing radiation are provided in dose equivalent units (mrem/yr) with no simple or universally accepted equivalence between these units; and 2) most states have not yet formally classified oil and gas drill rig personnel as occupational radiation workers.

Oil and gas NORM occurs in both liquid (produced waters), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the largest volume of NORM is in produced waters, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (scale) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also filter media from the treatment of production waters may concentrate NORM and require controls to limit radiation exposure to workers handling this material.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (see table below). Radon gas, the main human health concern from NORM, is produced by the decay of Radium-226, which occurs in the Uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Radionuclide Half-Lives

Radionuclide	Half-life	Mode of Decay
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of produced waters (>109 bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

6.9 Visual Impacts

Aesthetic impact occurs when there is a detrimental effect on the perceived beauty of a place or structure. Significant aesthetic impacts are those that may cause a diminishment of the public enjoyment and appreciation of an inventoried resource, or one that impairs the character or quality of such a place.

The requirement to assess impacts to visual resources was the subject of a topical response in the GEIS. The conclusion was that visual impacts from oil and gas drilling and completion activities are primarily minor and short-term, vary with topography, vegetation, and distance to viewer, and rarely trigger a need for site-specific comprehensive review or mitigating conditions such as limited drilling hours and camouflage or landscaping of the drill site. The Department's *Visual EAF Addendum* is available to conduct a comprehensive review of visual impacts when one is needed.[75]

The visual impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. They include drill site and access road clearing and grading, drill rig and equipment during the drilling phase, and production equipment if the well is viable. The 1992 GEIS stated that drill rigs vary in height from 30 feet for a small cable tool rig to 100 feet or greater for a large rotary, though the larger 100 foot rotary rigs are not commonly used in New York. By comparison, the rigs used for horizontal drilling could be 140 feet or greater and will have more supporting equipment. Additionally, the site clearing for the pad will increase from approximately two acres to approximately five acres. The most important difference, however, is in the duration of drilling and hydraulic fracturing. A horizontal well takes four to five weeks of 24 hours per day drilling to complete with an additional 3 to 5 days for the hydraulic fracture. This compares to the approximately one to two weeks or longer drill time as discussed in 1992. There was no mention of the time required for hydraulic fracturing in 1992.[76]

Multi-well pads will be slightly larger but the equipment used is often the same, resulting in similar visual issues as those associated with a single well pad. Based on industry response, a taller rig with a larger footprint and substructure, 170-foot total height, may be used for drilling consecutive wells on a pad. In other instances, smaller rigs may be used to drill the initial hole and conductor casing to just above the kick-off point. The larger rig would then be used for the final horizontal portion of the hole. Typically one or two wells are drilled and then the rig is removed. If the well(s) are viable, the rig is brought back and the remaining wells are drilled and

[75] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/visualeaf.pdf

[76] NTC, pp. 15-16

stimulated. As industry gains confidence in the production of the play, there is the possibility that all wells on a pad would be drilled, stimulated and completed consecutively, reducing the time frame of the visual impact. The regulations require that all wells on a multi-well pad be drilled within three years of starting the first well.[77]

The benefit of the multi-well pad is that it decreases the number of pads on the landscape. Current regulations allow for one single well pad per 40-acre spacing unit, one multi-well pad per 640-acre spacing unit or various other configurations as described in Section 5.1.3.2. Use of multi-well pads will reduce the number of long term visual impacts that result from reclaimed pads and production equipment and reduce the overall amount of land disturbance. The drilling technology also provides flexibility in pad location allowing visual impacts, both long and short-term, to be minimized as much as possible.[78]

Long term visual impacts of a pad after the drilling phase are determined by whether the well is a producer or a dry hole. In either case, reclamation work must begin with closure of any on-site reserve pit within 45 days of cessation of drilling and stimulation. If the well is a dry hole, the entire site will be reclaimed with very little permanent visual impact unless the site had been heavily forested, in which case the drilling will leave a changed landscape until trees grow back. All that will remain at a producing gas well site is an assembly of wellhead valves and auxiliary equipment such as meters, a dehydrator, a gas-water separator, a brine tank and a small fire-suppression tank. Multi-well pads may have somewhat larger equipment to handle the increased production. The remainder of a producing well site will be reclaimed with current well pads leaving as much as three acres for production equipment compared to less than one acre for a single well, as discussed in 1992.[79]

For informational purposes, Photos 6.2 - 6.13 depict a variety of actual wellsites in New York developed since the publication of the GEIS to illustrate their appearance during different stages of operations.

[77] NTC, pp. 15-16

[78] NTC, pp. 15-16

[79] NTC, pp. 15-16

6.10 Noise [80]

In NYS-DEC Policy DEP-00-1, noise is defined as any loud, discordant or disagreeable sound or sounds. More commonly, in an environmental context, noise is defined simply as unwanted sound. The environmental effects of sound and human perceptions of sound can be described in terms of the following four characteristics:

1) Sound Pressure Level (SPL may also be designated by the symbol L_p), or perceived loudness as expressed in decibels (dB) or A-weighted decibel scale dB(A) which is weighted towards those portions of the frequency spectrum, between 20 and 20,000 Hertz, to which the human ear is most sensitive. Both measure sound pressure in the atmosphere.

2) Frequency (perceived as pitch), the rate at which a sound source vibrates or makes the air vibrate.

3) Duration i.e., recurring fluctuation in sound pressure or tone at an interval; sharp or startling noise at recurring interval; the temporal nature (continuous vs. intermittent) of sound.

4) Pure tone, which is comprised of a single frequency. Pure tones are relatively rare in nature but, if they do occur, they can be extremely annoying.

[80] NTC, pp. 7-11

Photo 6.1- Electric Generators, Active Drilling
Site: Source: NTC Consulting

To aid staff in its review of a potential noise impact, Program Policy DEP-00-1 identifies three major categories of noise sources;

1) Fixed equipment or process operations;

2) Mobile equipment or process operations; and,

3) Transport movements of products, raw material or waste.

On Page 3 of its Notice of Determination of Non-Significance for a well drilled in Chemung County in 2002, the Department found that "Impacts associated with noise during drilling are directly related to the distance from a receptor. Drilling operations involve various sources of noise. The primary sources of noise were determined to be as follows:[81]

1) *Air Compressors:* Air compressors are typically powered by diesel engines, and generate the highest degree of noise over the course of drilling operations. Air

[81] Pages 4-5 - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002).

compressors will be in operation virtually throughout the drilling of a well. However, the actual number of operating compressors will vary.

2) *Tubular Preparation and Cleaning:* Tubular preparation and cleaning is an operation that is conducted as drill pipe is placed into the wellbore. As tubulars are raised onto the drill floor, workers physically hammer the outside of the pipe to displace internal debris. This process, when conducted during the evening hours, seems to generate the most concern from adjacent landowners. While the decibel level is comparatively low, the acute nature of the noise is noticeable.

3) *Elevator Operation:* Elevators are used to move drill pipe and casing into and/or out of the wellbore. During drilling, elevators are used to add additional pipe to the drill string as the depth increases. Elevators are used when the drilling contractor is removing multiple sections of pipe from the well or placing drill pipe or casing into the wellbore. Elevator operation is not a constant activity and its duration is dependent on the depth of the well bore. The decibel level is low.

4) *Drill Pipe Connections:* As the depth of the well increases, the drilling contractor must connect additional pipe to the drill string. Most operators in the Appalachian Basins use a method known as "air-drilling." As the drill bit penetrates the rock the cuttings must be removed from the wellbore. Cuttings are removed by displacing pressurized air (from the air compressors discussed above) into the well bore. As the air is circulated back to the surface, it carries with it the rock cuttings. To connect additional pipe to the drill string, the operator will release the air pressure. It is the release of pressure that creates a noise impact.

5) *Noise Generated by Support of Equipment and Vehicles:* Similar to any construction operation, drill sites require the use of support equipment and vehicles. Specialized cement equipment and vehicles, water trucks and pumps, flatbed tractor trailers and delivery and employee vehicles are the most common forms of support machinery and vehicles. Noise generated from these sources is consistent with other road-based vehicles. Cementing equipment will generate additional noise during operations but this impact is typically short lived and is at levels below that of the compressors described above.

Noise associated with the above activities is temporary and end once drilling operations cease.[82]

The noise impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. Site preparation and access road building will have noise that is associated with a construction site, including noise from bulldozers, backhoes, and other types of construction equipment. The rigs and supporting equipment are somewhat larger than the commonly-used equipment described in 1992, but with

[82] Page 4, - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002).

the exception of specialized downhole tools, horizontal drilling is performed using the same equipment, technology and procedures as many wells that have been drilled in New York. The basic procedures described for hydraulic fracturing are also the same. Production phase well site equipment is very quiet with negligible impacts.

The largest difference with relation to noise impacts, however, is in the duration of drilling. A horizontal well takes four to five weeks of 24-hours-per-day drilling to complete. The 1992 GEIS anticipated that most wells drilled in New York with rotary rigs would be completed in less than one week, though drilling could extend two weeks or longer.

High volume hydraulic fracturing is also of a larger scale than the water-gel fracs addressed in 1992. These were described as requiring 20,000 to 80,000 gallons of water pumped into the well at pressures of 2,000 to 3,500 psi. The procedure for a typical horizontal well requires one to three million or more gallons of water with a maximum casing pressure from 10,000 to 11,000 psi. This volume and pressure will result in more pump and fluid handling noise than anticipated in 1992. The proposed process requires three to five days to complete. There was no mention of the time required for hydraulic fracturing in 1992.

There will also be significantly more trucking and associated noise involved with high volume hydraulic fracturing than was addressed in the 1992 GEIS. In addition to the trucks required for the rig and its associated equipment, trucks are used to bring in water for drilling and hydraulic fracturing, sand for proppant, and frac tanks if pits are not used. Trucks are also used for the removal of flowback for the site. Estimates of truck trips per well are as follows:

Drill Pad and Road Construction Equipment	10 - 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 - 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 - 50 Truckloads
Completion Rig	15 Truckloads
Completion Fluid and Materials	10 - 20 Truckloads
Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads

This level of trucking could have negative noise impacts for those living in close proximity to the well site and access road. Like other noise associated with drilling this is temporary.
Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. Thus it is possible that someone living in close proximity to the pad will experience adverse noise impacts intermittently for up to three years.

The benefits of a multi-well pad are the reduced number of sites generating noise and, with the horizontal drilling technology, the flexibility to site the pad in the best location to mitigate the impacts. As described above and in more detail in Section 5.1.3.2, current regulations allow for one single well pad per 40-acre spacing unit, one multi-well pad per 640-acre spacing unit or various other combinations. This provides the potential for one multi-well pad to drain the same area that could contain up to 16 single well pads. With proper pad location and design the adverse noise impacts can be significantly reduced.

Multi-well pads also have the potential to greatly reduce the amount of trucking and associated noise in an area. Rigs and equipment may only need to be delivered and removed one time for the drilling and stimulation of all of the wells on the pad. Reducing the number of truck trips required for frac water is also possible by reusing water for multiple frac jobs. In certain instances it also may be economically viable to transport water via pipeline to a multi-well pad.

6.11 Road Use [83]

While the trucking for site preparation, rig, equipment, materials and supplies is similar for horizontal drilling to what was anticipated in 1992, the water requirement of high volume hydraulic fracturing could lead to significantly more truck traffic than was discussed in the GEIS. It is estimated that each horizontal well will need between one to three million gallons or more of water for stimulation. Estimates of truck trips per well are as follows:

Drill Pad and Road Construction Equipment	10 - 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 - 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 - 50 Truckloads
Completion Rig	15 Truckloads
Completion Fluid and Materials	10 - 20 Truckloads

[83] NTC, pp. 22-23

Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand Trucks	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads

As can be seen, trucking of hydraulic fracture equipment, water, sand and flow back removal is over 80% of the total. This trucking will take place in weeks-long periods before and after the hydraulic fracture.

Multi-well pads have the potential to reduce some of the total trucking in an area. Consecutively drilling and stimulating multiple wells from one pad will eliminate the trucking of equipment for single well pad to single well pad. Reduced water trucking is also a possibility. There is the potential to reuse flow back water for other fracturing operations. The centralized location of water impoundments may also make it economically viable for water to be brought in by pipeline or means other than trucking.

As discussed in 1992 regarding conventional vertical wells, trucking during the long term production life of a horizontally drilled single or multi-well pad will be insignificant.

6.12 Community Character Impacts[84]

Many of the community character impacts associated with horizontal drilling and high volume hydraulic fracturing are the same as those addressed in the 1992 GEIS, and no further mitigation measures are required. These include:

1) The possibility of injury to humans or the environment if site access is not properly restricted to prevent accidents or vandalism.

2) Temporal noise or visual impacts.

3) Temporary land use conflicts are identified in the discussion of unavoidable impacts.

4) Potential positive impacts from gas development identified including the availability of clean burning natural gas, generation of State and local taxes, revenues to landowners, and the multiplier effects of private investment in the State.

[84] NTC, pp. 21-23

5) Increased human activity and access to remote areas provided by the access roads as secondary impacts, with the former more intense during the drilling phase.

Community impacts related to horizontal drilling and high volume hydraulic fracturing needing further discussion include trucking, land use changes and environmental justice. Trucking is discussed in Section 6.11 of this Supplement.

6.12.1 Land Use Patterns

The spacing unit density for vertical shale wells is the same as discussed and anticipated in 1992. This density has been experienced in New York in Chautauqua and Seneca Counties without significant changes in land use patterns. The new drilling technology should not be expected to change the 1992 GEIS findings.

As mentioned previously, there is the option, not discussed in 1992, to use multi-well pads with a 640-acre spacing unit. This option has the potential to create less of an impact on community character by significantly reducing the total area required for roadways, pipelines, and well pads. While the pad will be larger and the activity at the location will be longer than for single well pads, the fewer total sites will reduce the cumulative changes to the host community, and should minimize loss or fragmentation of habitats, agricultural areas, forested areas, disruptions to scenic view sheds, and the like.

6.12.2 Environmental Justice

This is an issue that is not discussed in the 1992 GEIS. The United States Environmental Protection Agency definition is as follows: "Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work." The SGEIS/SEQRA process provides opportunity for public input and the resulting permitting procedures will apply state wide and provide equal protection to all communities and persons in New York. The location of drilling will be determined by where the gas is located and the resulting revenues will benefit the land owners and the surrounding community.

6.13 Cumulative Impacts[85]

Cumulative impacts are the effects of two or more single projects considered together. Adverse cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. The 1992 GEIS defines the project scope as an individual well with a limited discussion of cumulative impacts. Chapter 18 discusses the positive economic impacts of gas development for municipalities and for the entire State. Additionally, as an unavoidable adverse impact it states: "Though the potential for severe negative impacts from any one site is low. When all activities in the State are considered together, the potential for negative impacts on water quality, land use, endangered species and sensitive habitats increases significantly."

Cumulative impacts will be discussed from two perspectives;

1) **Site Specific** cumulative impacts beyond those considered in the 1992 GEIS resulting from multi-well pads and
2) **Regional** impacts which may be experienced as a result of gas development.

6.13.1 Site-Specific Cumulative Impacts

The potential for site specific cumulative impacts as a result of multi-well pads, while real, is easily quantified and can be adequately addressed during the application review process. General areas of concern with regard to noise, visual, and community character issues are the same as those of individual well pads. While the pads may be slightly larger than those used for single wells, the significant impacts are due to the cumulative time and trucking necessary to drill and stimulate each individual well.

When reviewed in 1992, it was assumed that a well pad would be constructed, drilled and reclaimed in a period measured in a few months, with the most significant activity being measured in one or two weeks for the majority of wells. By comparison, a horizontal well takes four to five weeks of 24-hour-per-day drilling with an additional three to five days for the

[85] NTC, pp. 26-31

hydraulic fracture. This duration will be required for each well, with industry indicating that it is common for six to eight wells to be drilled on a multi-well pad. Typically, one or two wells are drilled and stimulated and then the equipment is removed. If the well(s) are economically viable, the equipment is brought back and the remaining wells drilled and stimulated. Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. As industry gains confidence in the production of the play, there is the possibility that all wells on a pad would be drilled, stimulated and completed consecutively. This concept will shorten the time frame of noise generation and eliminate the noise generated by one rig disassembly/reassembly cycle.

The trucking requirements for rigging and equipment will not be significantly greater than for a single well pad, especially if all wells are drilled consecutively. Water and materials requirements, however, will greatly increase the amount of trucking to a multi-well pad compared to a single well pad. Estimates of truck trips per multi-well pad are as follows (assumes two rig and equipment deliveries and 8 wells):

Drill Pad and Road Construction Equipment	10 – 45 Truckloads
Drilling Rig	60 Truckloads
Drilling Fluid and Materials	200 – 400 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	200 – 400 Truckloads
Completion Rig	30 Truckloads
Completion Fluid and Materials	80 – 160 Truckloads
Completion Equipment – (pipe, wellhead)	10 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	300 – 400 Truckloads
Hydraulic Fracture Water	3,200 – 4,800 Tanker Trucks
Hydraulic Fracture Sand	160 – 200 Trucks
Flow Back Water Removal	1,600 – 2,400 Tanker Trucks

As can be seen, the vast majority of trucking is involved in delivering water and removing flow back. Multiple wells in the same location provide the potential to reduce this amount of trucking by reusing flow back water for the stimulation of other wells on the same pad. The centralized location of water impoundments may also make it economically viable to transport water via pipeline or rail in certain instances.

In the production phase, the operations at multi-well pads are similar to what was addressed in 1992. There will be a small amount of equipment, including valves, meters, dehydrators and tanks remaining on site, which may be slightly larger than what is used for single wells but is still minor and is quiet in operation. The reclamation procedures are the same as for single well pads, however, there will be more area left for production equipment and activities. It is anticipated that a multi-well pad will require up to three acres compared to one acre or less as discussed in 1992.

6.13.1.2 Site-Specific Cumulative Impacts Conclusions

A single multi-well pad on a 640-acre spacing unit will drain the same area that could contain up to 16 single well pads. As discussed earlier, the pad will be larger, the area left for production will be larger and, the duration of drilling and stimulating activities on the pad will be longer. The decrease in the number of drilling sites reduces the regional long term and short-term cumulative impacts.

6.13.2 Regional Cumulative Impacts

The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource, rig, equipment and crew availability, permitting and oversight capacity, leasing, and most importantly, economic factors. This holds true regardless of the type of drilling and stimulation utilized. Historically in New York, and in other plays around the country, development has occurred in a sequential manner over years with development activity concentrated in one area then moving on with previously drilled sites fully or partially reclaimed as new sites are drilled. As with the development addressed in 1992, once drilling and stimulation activities are completed and the sites have been reclaimed, the long term impact will consist of widely spaced and partially re-vegetated production sites and fully reclaimed plugged and abandoned well sites.

The statewide spacing regulations for vertical shale wells of one single well pad per 40-acre spacing unit will allow no greater density for horizontal drilling with high volume hydraulic fracturing than is allowed for conventional drilling techniques. This density was anticipated in 1992 and areas of New York, including Chautauqua, Cayuga and Seneca Counties, have experienced drilling at this level without significant negative impacts to agriculture, tourism, other land uses or any of the topics discussed in this report.

As discussed earlier, the density for multi-well pads, one per 640-acre spacing unit, is significantly less than for single well pads, reducing the total number of disturbances to the landscape. While multi-well pads will be slightly larger than single well pads the reduction in number will lead to a substantial decrease in the total amount of disturbed acreage, providing additional mitigation for long term visual and land use impacts on a regional basis. The following table provides an example for a 10 square mile area (i.e., 6,400 acres), completely drilled, comparing the 640 acre spacing option with multi-well pads and horizontal drilling to the 40 acre spacing option with single well pads and vertical drilling.

Spacing Option	**Multi-Well 640-Acre**	**Single Well 40-Acre**
Number of Pads	10	160
Total Disturbance - Drilling Phase	50 Acres (5 ac. per pad)	480 Acres (3 ac. per pad)
% Disturbance - Drilling Phase	.78	7.5
Total Disturbance - Production Phase	30 Acres (3 ac. per pad)	240 Acres (1.5 ac. per pad)
% Disturbance - Production Phase	.46	3.75

As can be seen, multi-well pads will significantly decrease the amount of disturbance on a regional basis in all phases of development. The reduction in sites should also allow for more resources to be devoted to proper siting and design of the pad and to mitigating the short-term impacts that occur during the drilling and stimulation phase.

6.13.2.1 Rate of Development and Thresholds

In response to questioning, a representative for one company estimated a peak activity for all of industry at 2,000 wells per year ± 25% in the New York Marcellus play. Other companies did not provide an estimate. By comparison, in Pennsylvania, where the reservoir is much more widespread, permitting activity is ongoing.

Year	Marcellus Permits Issued
2007	99
2008	510
2009 (Through 8/31)	1127

SOURCE: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG09.htm

Recent development in the Barnett play in Texas, which utilizes the same horizontal drilling with high volume hydraulic fracturing that will be used in New York, has occurred at a rapid rate over the last decade. It is an approximately 4,000 square mile play located in and around the Dallas – Fort Worth area. In the eight-year period from 2002 to 2008 approximately 10,500 wells were drilled.

The final scoping document summarizes the challenge of forecasting rates of development as follows:

> The number of wells which will ultimately be drilled cannot be known in advance, in large part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. Changes in the market and other economic conditions also have an impact on whether and how quickly individual wells are drilled.[86]

Additional research has identified that "Experience developing shale gas plays in the past 20 years has demonstrated that every shale play is unique."[87] Each individual play has been defined, tested and expanded based on an understanding of the resource distribution, natural fracture patterns, and limitations of the reservoir, and each play has required solutions to problems and issues required for commercial production. Many of these problems and solutions are unique to the play.[88]

The timing, rate and pattern of development, on either a statewide or local basis, are very difficult to accurately predict.[89] As detailed in Section 2.1.6 of the Final Scoping Document, "overall site density is not likely to be greater than was experienced and envisioned when the GEIS and its Findings were finalized and certified in 1992."

The rate of development cannot be predicted with any certainty based on the factors cited above and in the Final Scoping Document. Nor is it possible to define the threshold at which development results in adverse noise, visual and community character impacts. Some people will feel that one drilling rig on the landscape is too many, while others will find the changes in

[86] Final Scoping Document (Page 39)

[87] Fractured Shale Gas Potential in New York (Page 1)

[88] Ibid

[89] Final Scoping Document (Page 39)

the landscape inoffensive and will want full development of the resource as quickly as possible. There is no way to objectify these inherently subjective perspectives. As a result, there is no supportable basis on which to set a limit on the rate of development of the Marcellus and other low-permeability gas reservoirs.

It is certain that widespread development of the Marcellus shale as described in this document will have community impacts that will change the quality of life in the affected areas in the short term. For purposes of this review, however, there is no sound basis for an administrative determination limiting the shale development on the basis of those changes at this time. Accordingly, any limitation on development, aside from the mitigation measures discussed in the next chapter, is more appropriately considered in the context of policy making, primarily at the local level, outside of the SGEIS.

6.14 Seismicity[90]

Economic development of natural gas from low permeability formations requires the target formation to be hydraulically fractured to increase the rock permeability and expose more rock surface to release the gas trapped within the rock. The hydraulic fracturing process fractures the rock by controlled application of hydraulic pressure in the wellbore. The direction and length of the fractures are managed by carefully controlling the applied pressure during the hydraulic fracturing process.

The release of energy during hydraulic fracturing produces seismic pressure waves in the subsurface. Microseismic monitoring commonly is performed to evaluate the progress of hydraulic fracturing and adjust the process, if necessary, to limit the direction and length of the induced fractures. Chapter 4 of this Supplement presents background seismic information for New York. Concerns associated with the seismic events produced during hydraulic fracturing are discussed below.

[90] Alpha, Section 7; discussion was provided for NYSERDA by Alpha Environmental, Inc., and Alpha's references are included for informational purposes.

6.14.1 Hydraulic Fracturing-Induced Seismicity

Seismic events that occur as a result of injecting fluids into the ground are termed "induced." There are two types of induced seismic events that may be triggered as a result of hydraulic fracturing. The first is energy released by the physical process of fracturing the rock which creates microseismic events that are detectable only with very sensitive monitoring equipment. Information collected during the microseismic events is used to evaluate the extent of fracturing and to guide the hydraulic fracturing process. This type of microseismic event is a normal part of the hydraulic fracturing process used in the development of both horizontal and vertical oil and gas wells, and by the water well industry.

The second type of induced seismicity is fluid injection of any kind, including hydraulic fracturing, which can trigger seismic events ranging from imperceptible microseismic, to small-scale, "felt" events, if the injected fluid reaches an existing geologic fault. A "felt" seismic event is when earth movement associated with the event is discernable by humans at the ground surface. Hydraulic fracturing produces microseismic events, but different injection processes, such as waste disposal injection or long term injection for enhanced geothermal, may induce events that can be felt, as discussed in the following section. Induced seismic events can be reduced by engineering design and by avoiding existing fault zones.

6.14.1.1 Background

Hydraulic fracturing consists of injecting fluid into a wellbore at a pressure sufficient to fracture the rock within a designed distance from the wellbore. Other processes where fluid is injected into the ground include deep well fluid disposal, fracturing for enhanced geothermal wells, solution mining and hydraulic fracturing to improve the yield of a water supply well. The similar aspect of these methods is that fluid is injected into the ground to fracture the rock; however, each method also has distinct and important differences.

There are ongoing and past studies that have investigated small, felt, seismic events that may have been induced by injection of fluids in deep disposal wells. These small seismic events are not the same as the microseismic events triggered by hydraulic fracturing that can only be detected with the most sensitive monitoring equipment. The processes that induce seismicity in both cases are very different.

Deep well injection is a disposal technology which involves liquid waste being pumped under moderate to high pressure, several thousand feet into the subsurface, into highly saline, permeable injection zones that are confined by more shallow, impermeable strata (FRTR, August 12, 2009). The goal of deep well injection is to store the liquids in the confined formation(s) permanently.

Carbon sequestration is also a type of deep well injection, but the carbon dioxide emissions from a large source are compressed to a near liquid state. Both carbon sequestration and liquid waste injection can induce seismic activity. Induced seismic events caused by deep well fluid injection are typically less than a magnitude 3.0 and are too small to be felt or to cause damage. Rarely, fluid injection induces seismic events with moderate magnitudes, between 3.5 and 5.5, that can be felt and may cause damage. Most of these events have been investigated in detail and have been shown to be connected to circumstances that can be avoided through proper site selection (avoiding fault zones) and injection design (Foxall and Friedmann, 2008).

Hydraulic fracturing also has been used in association with enhanced geothermal wells to increase the permeability of the host rock. Enhanced geothermal wells are drilled to depths of many thousands of feet where water is injected and heated naturally by the earth. The rock at the target depth is fractured to allow a greater volume of water to be re-circulated and heated. Recent geothermal drilling for commercial energy-producing geothermal projects have focused on hot, dry, rocks as the source of geothermal energy (Duffield, 2003). The geologic conditions and rock types for these geothermal projects are in contrast to the shallower sedimentary rocks targeted for natural gas development. The methods used to fracture the igneous rock for geothermal projects involve high pressure applied over a period of many days or weeks (Florentin 2007 and Geoscience Australia, 2009). These methods differ substantially from the lower pressures and short durations used for natural gas well hydraulic fracturing.

Hydraulic fracturing is a different process that involves injecting fluid under higher pressure for shorter periods than the pressure level maintained in a fluid disposal well. A horizontal well is fractured in stages so that the pressure is repeatedly increased and released over a short period of time necessary to fracture the rock. The subsurface pressures for hydraulic fracturing are sustained typically for one or two days to stimulate a single well, or for approximately two weeks at a multi-well pad. The seismic activity induced by hydraulic fracturing is only detectable at the surface by very sensitive equipment.

Avoiding pre-existing fault zones minimizes the possibility of triggering movement along a fault through hydraulic fracturing. It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing. Generally, operators will avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process. The presence of faults also potentially reduces the optimal recovery of gas and the economic viability of a well or wells.

Injecting fluid into the subsurface can trigger shear slip on bedding planes or natural fractures resulting in microseismic events. Fluid injection can temporarily increase the stress and pore pressure within a geologic formation. Tensile stresses are formed at each fracture tip, creating shear stress (Pinnacle; "FracSeis;" August 11, 2009). The increases in pressure and stress reduce the normal effective stress acting on existing fault, bedding, or fracture planes. Shear stress then overcomes frictional resistance along the planes, causing the slippage (Bou-Rabee and Nur, 2002). The way in which these microseismic events are generated is different than the way in which microseisms occur from the energy release when rock is fractured during hydraulic fracturing.

The amount of displacement along a plane that is caused by hydraulic fracturing determines the resultant microseism's amplitude. The energy of one of these events is several orders of magnitude less than that of the smallest earthquake that a human can feel (Pinnacle; "Microseismic;" August 11, 2009). The smallest measurable seismic events are typically between 1.0 and 2.0 magnitude. In contrast, seismic events with magnitude 3.0 are typically large enough to be felt by people. Many induced microseisms have a negative value on the MMS. Pinnacle Technologies, Inc. has determined that the characteristic frequencies of microseisms are between 200 and 2,000 Hertz; these are high-frequency events relative to typical seismic data. These small magnitude events are monitored using extremely sensitive instruments that are positioned at the fracture depth in an offset wellbore or in the treatment well (Pinnacle; "Microseismic;" August 11, 2009). The microseisms from hydraulic fracturing can barely be measured at ground surface by the most sensitive instruments (Sharma, personal communication, August 7, 2009).

There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing. Nonetheless, operators monitor the hydraulic fracturing process to optimize the results for successful gas recovery. It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process.

The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments. Multiple receivers on a wireline array are placed in one or more offset borings (new, unperforated well(s) or older well(s) with production isolated) or in the treatment well to detect microseisms and to monitor the hydraulic fracturing process. The microseism locations are triangulated using the arrival times of the various p- and s-waves with the receivers in several wells, and using the formation velocities to determine the location of the microseisms. A multi-level vertical array of receivers is used if only one offset observation well is available. The induced fracture is interpreted to lie within the envelope of mapped microseisms (Pinnacle; "FracSeis;" August 11, 2009).

Data requirements for seismic monitoring of a hydraulic fracturing treatment include formation velocities (from a dipole sonic log or cross-well tomogram), well surface and deviation surveys, and a source shot in the treatment well to check receiver orientations, formation velocities and test capabilities. Receiver spacing is selected so that the total aperture of the array is about half the distance between the two wells. At least one receiver should be in the treatment zone, with another located above and one below this zone. Maximum observation distances for microseisms should be within approximately 2500 ft of the treatment well; the distance is dependent upon formation properties and background noise level (Pinnacle; "FracSeis;" August 11, 2009).

6.14.1.2 Recent Investigations and Studies

Hydraulic fracturing has been used by oil and gas companies to stimulate production of vertical wells in New York State since the 1950s. Despite this long history, there are no records of induced seismicity caused by hydraulic fracturing in New York State. The only induced seismicity studies that have taken place in New York State are related to seismicity suspected to have been caused by waste fluid disposal by injection and a mine collapse, as identified in Section 4.5.4. The seismic events induced at the Dale Brine Field (Section 4.5.4) were the result of the injection of fluids for extended periods of time at high pressure for the purpose of salt solution mining. This process is significantly different from the hydraulic fracturing process that will be undertaken for developing the Marcellus and other low permeability shales in New York.

Gas producers in Texas have been using horizontal drilling and high-volume hydraulic fracturing to stimulate gas production in the Barnett Shale for the last decade. The Barnett is geologically similar to the Marcellus, but is found at a greater depth; it is a deep shale with gas stored in unconnected pore spaces and adsorbed to the shale matrix. High-volume hydraulic fracturing allows recovery of the gas from the Barnett to be economically feasible. The horizontal drilling and high-volume hydraulic fracturing methods used for the Barnett shale play are similar to those that would be used in New York State to develop the Marcellus, Utica, and other gas bearing shales.

Alpha contacted several researchers and geologists who are knowledgeable about seismic activity in New York and Texas, including:

- Mr. John Armbruster, Staff Associate, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Cliff Frohlich, Associate Director of the Texas Institute for Geophysics, The University of Texas at Austin
- Dr. Won-Young Kim, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Mr. Eric Potter, Associate Director of the Texas Bureau of Economic Geology, The University of Texas at Austin
- Mr. Leonardo Seeber, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Mukul Sharma, Professor of Petroleum and Geosystems Engineering, The University of Texas at Austin
- Dr. Brian Stump, Albritton Professor, Southern Methodist University

None of these researchers have knowledge of any seismic events that could be explicitly related to hydraulic fracturing in a shale gas well. Mr. Eric Potter stated that approximately 12,500 wells in the Barnett play and several thousand wells in the East Texas Basin (which target tight gas sands) have been stimulated using hydraulic fracturing in the last decade, and there have been no documented connections between wells being fractured hydraulically and felt quakes (personal communication, August 9, 2009). Dr. Mukul Sharma confirmed that microseismic events associated with hydraulic fracturing can only be detected using very sensitive instruments (personal communication, August 7, 2009).

The Bureau of Geology, the University of Texas' Institute of Geophysics, and Southern Methodist University are planning to study earthquakes measured in the vicinity of the Dallas–Fort Worth (DFW) area, and Cleburne, Texas, that appear to be associated with salt water disposal wells, and oil and gas wells. The largest quakes in both areas were magnitudes of 3.3, and more than 100 earthquakes with magnitudes greater than 1.5 have been recorded in the DFW area in 2008 and 2009. There is considerable oil and gas drilling and deep brine disposal wells in the area and a small fault extends beneath the DFW area. Dr. Frohlich recently stated that "[i]t's always hard to attribute a cause to an earthquake with absolute certainty." Dr. Frohlich has two manuscripts in preparation with Southern Methodist University describing the analysis of the DFW activity and the relationship with gas production activities (personal communication, August 4 and 10, 2009). Neither of these manuscripts was available before this document was completed. Nonetheless, information posted online by Southern Methodist University (SMU, 2009) states that the research suggests that the earthquakes seem to have been caused by injections associated with a deep brine disposal well, and not with hydraulic fracturing operations.

6.14.1.3 Correlations between New York and Texas

The gas plays of interest, the Marcellus and Utica shales in New York and the Barnett shale in Texas, are relatively deep, low permeability, gas shales deposited during the Paleozoic Era. Horizontal drilling and high-volume hydraulic fracturing methods are required for successful, economical gas production. The Marcellus shale was deposited during the early Devonian, and the slightly younger Barnett was deposited during the late Mississippian. The depth of the Marcellus in New York ranges from exposure at the ground surface in some locations in the northern Finger Lakes area to 7,000 feet or more below the ground surface at the Pennsylvania border in the Delaware River valley. The depth of the Utica shale in New York ranges from exposure at the ground surface along the southern Adirondacks to more than 10,000 feet along the New York Pennsylvania border.

Conditions for economic gas recovery likely are present only in portions of the Marcellus and Utica members, as described in Chapter 4. The thickness of the Marcellus and Utica in New York ranges from less than 50 feet in the southwestern portion of the state to approximately 250 feet at the south-central border. The Barnett shale is 5,000 to 8,000 feet below the ground surface and 100 to 500 feet thick (Halliburton; August 12, 2009). It is estimated that the entire Marcellus shale may hold between 168 and 516 trillion cubic feet of gas; in contrast, the Barnett has in-place gas reserves of approximately 26.2 trillion cubic feet (USGS, 2009A) and covers approximately 4 million acres.

The only known induced seismicity associated with the stimulation of the Barnett wells are microseisms that are monitored with downhole transducers. These small-magnitude events triggered by the fluid pressure provide data to the operators to monitor and improve the fracturing operation and maximize gas production. The hydraulic fracturing and monitoring operations in the Barnett have provided operators with considerable experience with conditions similar to those that will be encountered in New York State. Based on the similarity of conditions, similar results are anticipated for New York State; that is, the microseismic events will be unfelt at the surface and no damage will result from the induced microseisms. Operators are likely to monitor the seismic activity in New York, as in Texas, to optimize the hydraulic fracturing methods and results.

6.14.1.4 Affects of Seismicity on Wellbore Integrity

Wells are designed to withstand deformation from seismic activity. The steel casings used in modern wells are flexible and are designed to deform to prevent rupture. The casings can withstand distortions much larger than those caused by earthquakes, except for those very close to an earthquake epicenter. The magnitude 6.8 earthquake event in 1983 that occurred in Coalinga, California, damaged only 14 of the 1,725 nearby active oilfield wells, and the energy released by this event was thousands of times greater than the microseismic events resulting from hydraulic fracturing. Earthquake-damaged wells can often be re-completed. Wells that cannot be repaired are plugged and abandoned (Foxall and Friedmann, 2008). Induced seismicity from hydraulic fracturing is of such small magnitude that it is not expected to have any effect on wellbore integrity.

6.14.2 Summary of Potential Seismicity Impacts

The issues associated with seismicity related to hydraulic fracturing addressed herein include seismic events generated from the physical fracturing of the rock, and possible seismic events produced when fluids are injected into existing faults.

The possibility of fluids injected during hydraulic fracturing the Marcellus or Utica shales reaching a nearby fault and triggering a seismic event are remote for several reasons. The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica shales. Similarly, the paucity of historic seismic events and the low seismic risk level in the fairways for these shales indicates that geologic conditions generally are stable in these areas. By definition, faults are planes or zones of broken or fractured rock in the subsurface. The geologic conditions associated with a fault generally are unfavorable for hydraulic fracturing and economical production of natural gas. As a result, operators typically endeavor to avoid faults for both practical and economic considerations. It is prudent for an applicant for a drilling permit to evaluate and identify known, significant, mapped, faults within the area of effect of hydraulic fracturing and to present such information in the drilling permit application. It is Alpha's opinion that an independent pre-drilling seismic survey probably is unnecessary in most cases because of the relatively low level of seismic risk in the fairways of the Marcellus and Utica shales. Additional evaluation or monitoring may be necessary if hydraulic fracturing fluids might reach a known, significant, mapped fault, such as the Clarendon-Linden fault system.

Recent research has been performed to investigate induced seismicity in an area of active hydraulic fracturing for natural gas development near Fort Worth, Texas. Studies also were performed to evaluate the cause of the earthquakes associated with the solution mining activity near the Clarendon-Linden fault system near Dale, N.Y. in 1971. The studies indicated that the likely cause of the earthquakes was the injection of fluid for brine disposal for the incidents in

Texas, and the injection of fluid for solution mining for the incidents in Dale, N.Y. The studies in Texas also indicate that hydraulic fracturing is not likely the source of the earthquakes.

The hydraulic fracturing methods used for enhanced geothermal energy projects are appreciably different than those used for natural gas hydraulic fracturing. Induced seismicity associated with geothermal energy projects occurs because the hydraulic fracturing is performed at greater depths, within different geologic conditions, at higher pressures, and for substantially longer durations compared with the methods used for natural gas hydraulic fracturing.

There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed in preparing this discussion indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells.

Seismic monitoring by the operators is performed to evaluate, adjust, and optimize the hydraulic fracturing process. Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude. The existing and well-established seismic monitoring network in New York is sufficient to document the locations of larger-scale seismic events and will continue to provide additional data to monitor and evaluate the likely sources of seismic events that are felt.

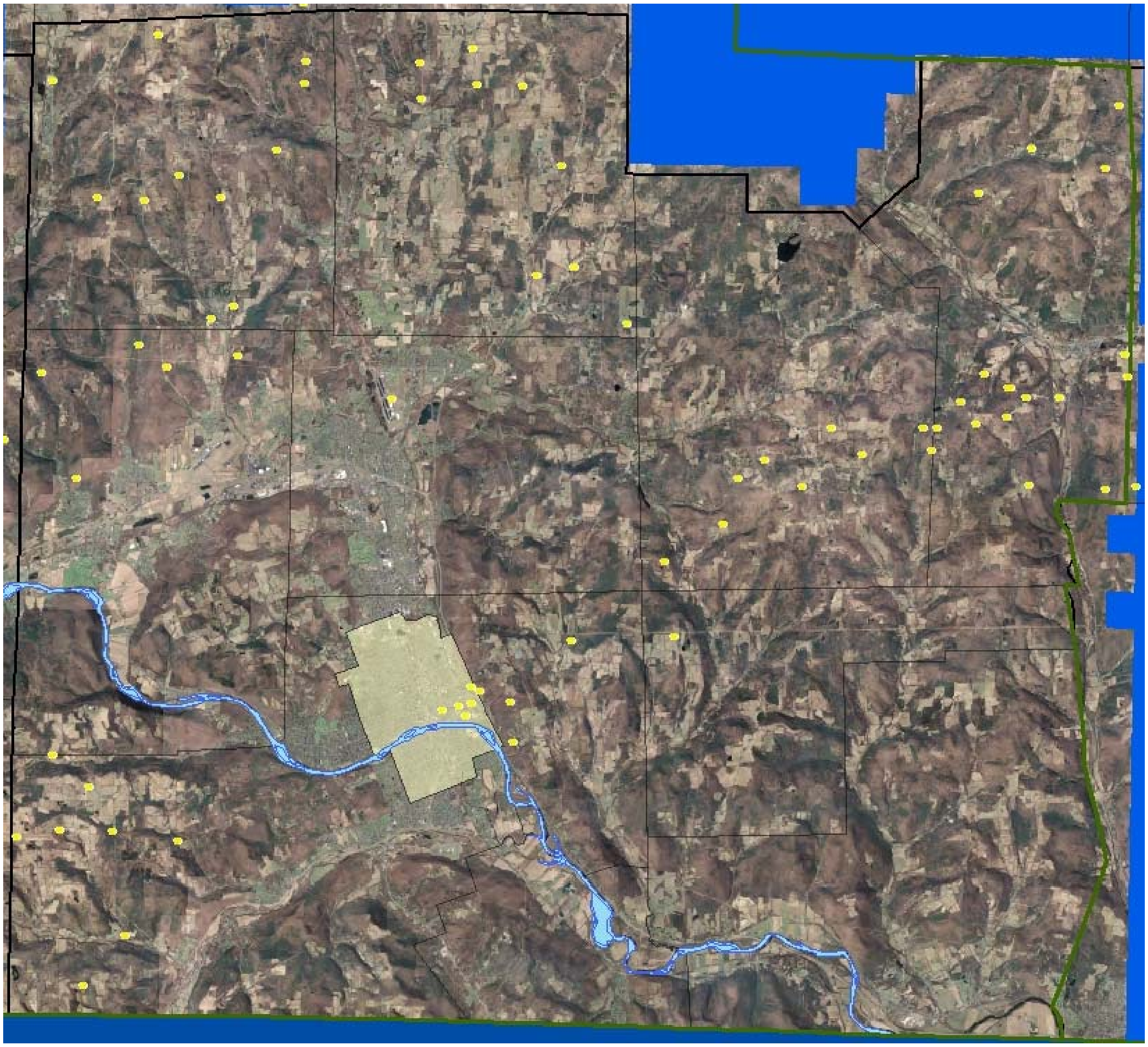
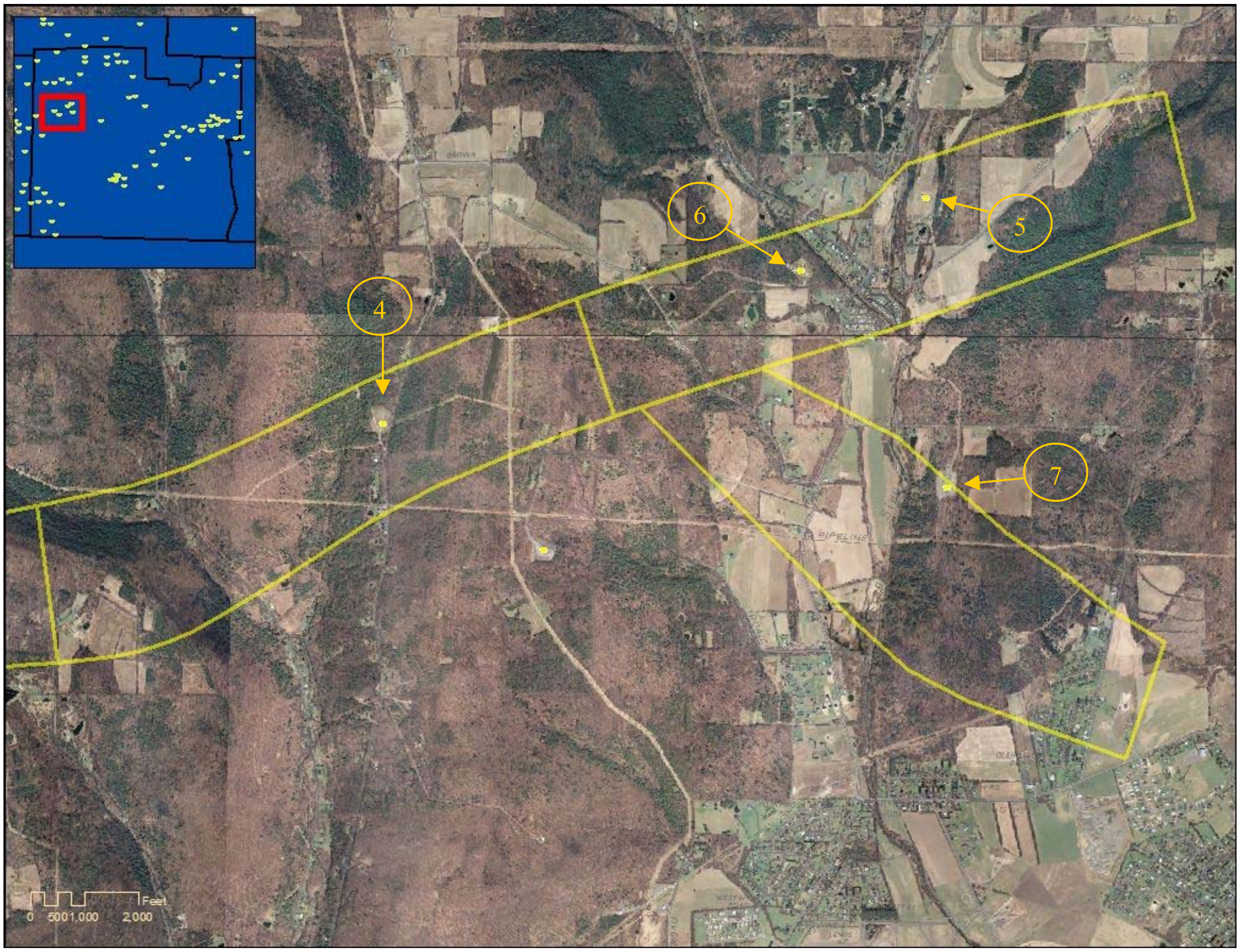


Photo 6.2 The following series of photos shows Trenton-Black River wells in Chemung County. These wells are substantially deeper than Medina wells, and are typically drilled on 640 acre units. Although the units and well pads typically contain one well, the size of the well units and pads is closer to that expected for multi-well Marcellus pads. Unlike expected Marcellus wells, Trenton-Black River wells target geologic features that are typically narrow and long. Nevertheless, photos of sections of Trenton-Black River fields provide an idea of the area of well pads within producing units.

The above photo of Chemung County shows Trenton-Black River wells and also historical wells that targeted other formations. Most of the clearings visible in this photo are agricultural fields.

Photo 6.3 The Quackenbush Hill Field is a Trenton-Black River field that runs from eastern Steuben County to north-west Chemung County. The discovery well for the field was drilled in 2000. The above map shows five wells in the eastern end of the field. Note the relative proportion of well pads to area of entire well units. We unit sizes shown are approximately 640 acres, similar to expected Marcellus Shale multi-well pad units.



Photos 6.4 Well #4 (Hole number 22853) was a vertical completed in February 2001 at a total vertical depth of 9,682 feet. The drill site disturbed area was approximately 3.5 acres. The site was subsequently reclaimed to a fenced area of approximately 0.35 acres for production equipment. Because this is a single-well unit, it contains fewer tanks and other equipment than a Marcellus multi-well pad. The surface within a T-BR well fenced area is typically covered with gravel.

Rhodes 1322 11/13/2001

Rhodes 1322 5/6/2009

Photos 6.5 Well #5 (Hole number 22916) was completed as a directional well in 2002. Unit size is 636 acres. Total drill pad disturbed area was approximately 3 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Gregory #1446A 12/27/2001

Gregory #1446A 5/6/2009

Photo 6.6 Well #6 (Hole number 23820) was drilled as a horizontal infill well in 2006 in the same unit as Well #6. Total drill pad disturbed area was approximately 3.1 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Schwingel #2 5/6/2009

Photos 6.7 Well #7 (Hole number 23134) was completed as a horizontal well in 2004 to a vertical depth of 9,695 and a total drilled depth of 12,050 feet Well unit size is 624 acres. The drill pad disturbed area was approximately 4.2 acres which has been reclaimed to a gravel pad of approximately 1.3 acres of which approximately 0.5 acres is fenced for equipment.

Soderblom #1 8/19/2004

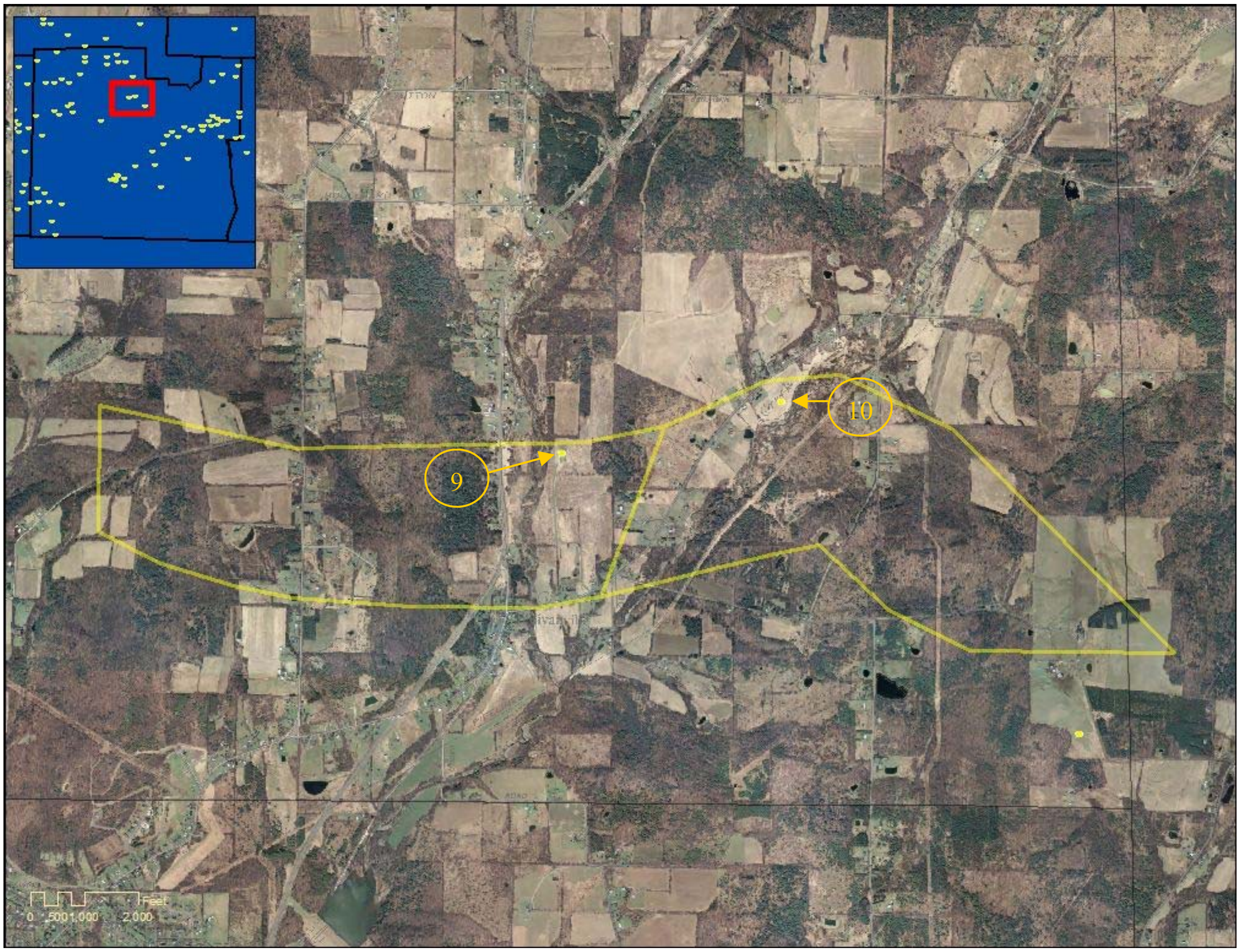
Soderblom #1 8/19/2004

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Photo 6.8 This photo shows two Trenton-Black River wells in north-central Chemung County. The two units were established as separate natural gas fields, the Veteran Hill Field and the Brick House Field.



Photos 6.9 Well #9 (Hole number 23228) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a total vertical depth of 9,461 and a total drilled depth of 12,550 feet. The well unit is approximately 622 acres.

Little 1 10/6/2005

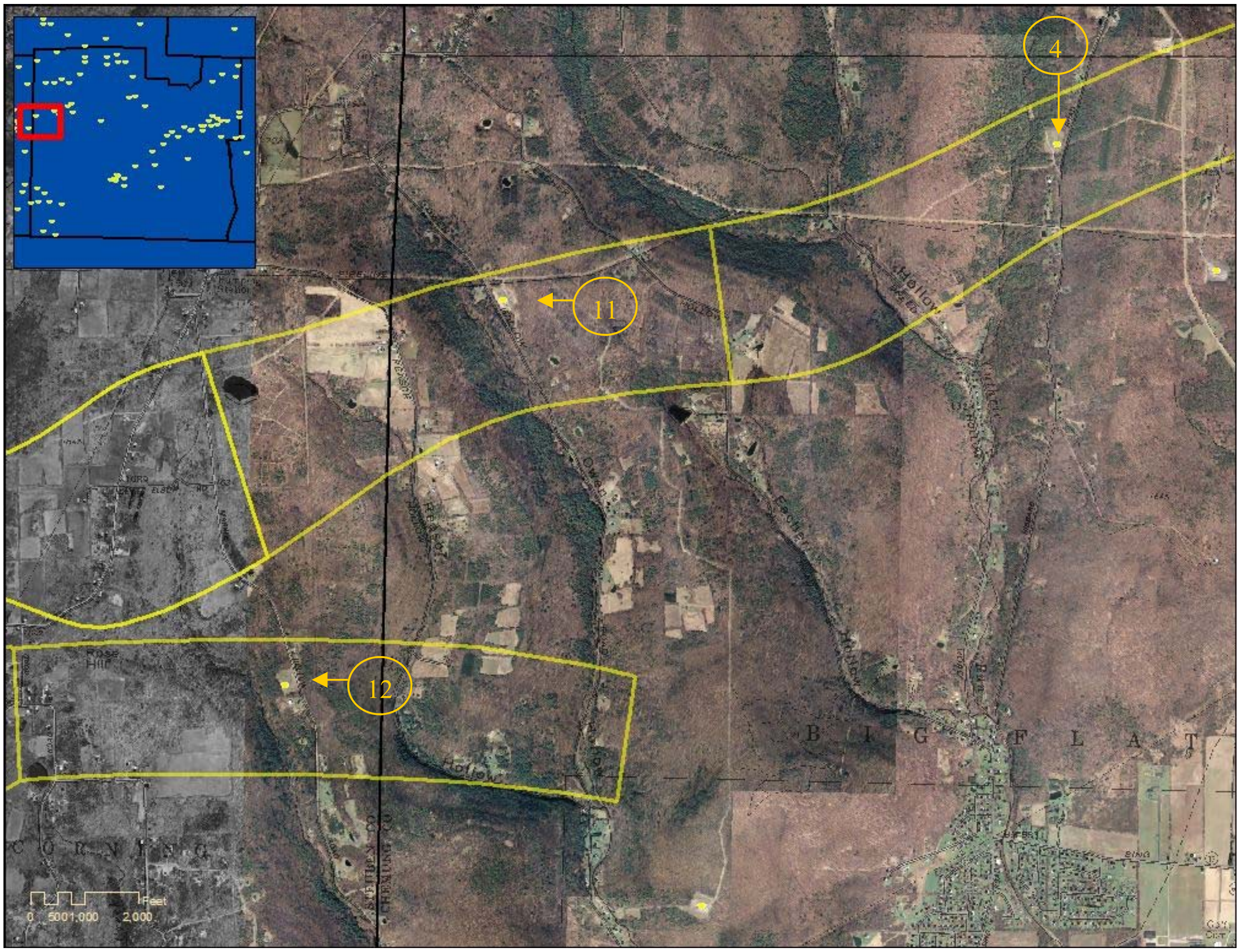
Little 1 11/3/2005

Photos 6.10 Well #10 (Hole number 23827) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a total vertical depth of 9,062 and a total drilled depth of 13,360 feet. The production unit is approximately 650 acres.

Hulett #1 10/5/2006

Hulett #1 5/6/2009

Photo 6.11 This photo shows another portion of the Quackenbush Hill Field in western Chemung County and eastern Steuben County. As with other portions of Quackenbush Hill Field, production unit sizes are approximately 640 acres each.



Photos 6.12 Well #11 (Hole number 22831) was completed in 2000 as a directional well to a total vertical depth of 9,824 feet. The drill site disturbed area was approximately 3.6 acres which has been reclaimed to a fenced area of 0.5 acres.

Lovell 11/13/2001

Lovell 5/6/2009

Photos 6.13 Well #12 (Hole number 22871) was completed in 2002 as a horizontal well to a total vertical depth of 9,955 feet and a total drilled depth of 12,325 feet. The drill site disturbed area was approximately 3.2 acres which has been reclaimed to a fenced area of 0.45 acres.

Henkel 10/22/2002

Henkel 5/6/2009

Chapter 7 – Mitigation Measures

Chapter 7 MITIGATION MEASURES

Many of the potential impacts identified in Chapter 6 are mitigated by existing regulatory programs, both within and outside of DEC. These are identified and described in this chapter, along with recommendations for enhanced procedures and permit conditions necessitated by the unique aspects of horizontal drilling and high-volume hydraulic fracturing. In addition, the proposed EAF Addendum contains a series of informational requirements, such as the disclosure of additives, the proposed volume of fluids used for fracturing, the percentage weight of water, proppants and each additive, and mandatory pre-drilling plans, that also serve as mitigation measures. As with Chapter 6, this Supplement text is not exhaustive with respect to mitigation measures because it incorporates by reference the entire 1992 GEIS and Findings Statement. This document focuses on:

1) mitigation of impacts not addressed by the GEIS (e.g., water withdrawal) and
2) enhancements to GEIS mitigation measures to target potential impacts associated with horizontal drilling, multi-well pad development and high-volume hydraulic fracturing.

Although every single mitigation measure provided by the GEIS is not reiterated herein, such measures remain available and applicable as warranted.

7.1 Protecting Water Resources

The Department is authorized by statute to require the drilling, casing, operation, plugging and replugging of wells and reclamation of surrounding land to, among other things, prevent or remedy "the escape of oil, gas, brine or water out of one stratum into another" and "the pollution of fresh water supplies by oil, gas, salt water or other contaminants."[1]

In addition to its specific authority to regulate well operations to protect the environment, the Department also has broad authority to "[p]romote and coordinate management of water . . . resources to assure their protection, enhancement, provision, allocation and balanced utilization . . . and take into account the cumulative impact upon all of such resources in making any determination in connection with any . . . permit . . ."[2]

7.1.1 Water Withdrawal Regulatory and Oversight Programs

Existing jurisdictions and regulatory programs address some concerns regarding the impacts related to water withdrawal that are described in Chapter 6. These programs are summarized below, followed by a discussion of three methodologies for mitigating impacts from surface water withdrawals. These are DRBC's method, SRBC's method and the Natural Flow Regime Method, which is preferred by the Department for purposes of the development of gas reserves as described in this document and will be employed unless and until further regulatory guidance or regulations are formally adopted. Mitigation of cumulative impacts is also addressed.

7.1.1.1 NYSDEC Jurisdictions

Degradation of Water Use

Public Water Supply - New York State currently regulates public drinking water supply ground and surface water withdrawals through the public water supply permit program[3] . The NYSDEC also specifically regulates all significant ground water withdrawals for any purpose. These limited water supply permit programs help to protect and conserve available water supplies.

Other Water Withdrawals - NYSDEC also regulates non-public water supply withdrawals in Long Island counties from wells with pumping capacities in excess of 45 gallons per minute. (ECL 15-1527). All water withdrawals within New York's portion of the great lakes basin of 100,000 gallons per day or more (30 day average) must register with the Department (ECL 15-

[1] ECL §23-0305(8)(d)

[2] ECL §23-0301(1)(b)

[3] *Environmental Conservation Law Article 15 Title 15*

1605). Also, all withdrawals within New York's portion of the Delaware and Susquehanna river basins greater than 100,000 gpd must have the approval of the respective basin commission. Although they may be subject to the reporting and registration requirements described below, surface and ground water withdrawals that are not on Long Island and not for drinking water supply currently are unregulated unless the withdrawals occur within the lands regulated by the DRBC and the SRBC. Surface water withdrawals are subject to the recently enacted narrative water quality standard for flow promulgated at 6 NYCRR 703.2. This water quality standard generally prohibits any alteration in flow that would impair a fresh surface waterbody's designated best use.[1] Determination of an appropriate passby flow needs to be done on a case by case basis. However, the TOGS that is necessary to provide effective guidance on the application of the narrative water quality for flow has not been promulgated. For the purpose of this SGEIS only, the Department intends to employ the Natural Flow Regime Method as an interim protection measure in lieu of the flow standard pending completion of the flow standard TOGS.

Water Withdrawal Reporting - Recently passed legislation[4] requires any entity that withdraws, or that has the capacity to withdraw, ground water or surface water in quantities greater than 100,000 gallons per day to file an annual report with the NYSDEC. Inter-basin diversions must be reported on the same form.

Great Lakes Basin Registration - With the exception of water withdrawals subject to ECL Article 15, Title 15 Public Water Supply permits, any existing withdrawal of surface or ground water from the Great Lakes Basin of more than 100,000 gallons per day averaged over a 30 day period must be registered with the Department's Division of Water.

Reduced Stream Flow

The NYSDEC primarily addresses the withdrawal of water and its potential impacts in the following regulations:

- 6 NYCRR 601: Water Supply
- 6 NYCRR 675: Great Lakes Withdrawal Registration Regulations

[4] *ECL Article 15, Title 33*

The requirements of 6 NYCRR 601 pertain to public water supply withdrawals and include an application that describes the project (map, engineer's report and project justification) and the proposed water withdrawal. The applicant is required to identify the source of water, projected withdrawal amounts and detailed information on rainfall and streamflow.

The purpose of 6 NYCRR 675 is to establish requirements for the registration of water withdrawals and reporting of water losses in the Great Lakes Basin. Part 675 is applicable because a portion of the shales considered for potential high-volume fracturing are located within the Great Lakes Basin. Registration is required for non-agricultural purposes in excess of 100,000 gallons per day (30 day consecutive period). An application for withdrawal in the Great Lakes basin is required and addresses location and source of withdrawal, return flow, water usage description, annual and monthly volumes of withdrawal, water loss and a list of other regulatory (federal, state and local) requirements. There are also additional requirements for inter-basin surface water diversions.

Impacts to Aquatic Ecosystems

With respect to disturbances of surface water bodies such as rivers and streams, equipment or structures such as standpipes may require permits under Article 15 of the ECL. The NYSDEC has authority to control the use and protection of the waters of New York State through 6NYCRR, Part 608, Use and Protection of Waters. This regulation enables the agency to control any change, modification or disturbance to a "protected stream", which includes all navigable streams and any stream or portion of a stream with a classification or standard of AA, AA(t), A, A(t), B, B(t) or C(t), and "navigable waters". 6 NYCRR Part 608 regulates the use and protection of waters in the state, and has subparts that address the protection of fish and wildlife species. Under Part 608.2, "No person or local public corporation may change, modify or disturb any protected stream, its bed or banks, nor remove from its bed or banks sand, gravel or other material, without a permit issued pursuant to this Part". The Department reviews permits for changes, modifications, or disturbances to streams with respect to potential environmental impacts on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality; hydrology; and water course and waterbody integrity. Part 608 does not regulate disturbances of the many streams classified as "C" or below.

Impacts to Wetlands

Actions located within 100 feet of wetlands regulated by Article 24 of the ECL generally require a permit from DEC. Thus, the placement of a structure to withdraw surface water or to withdraw groundwater within 100 feet of the wetland requires a permit. Permits for these structures can only be granted if there is no alternative to placement within 100 feet. If there is no alternative location, a permit can only be granted if the structure has no impact on the wetlands or if that impact is outweighed by an economic and social need.

Aquifer Depletion

The concern for aquifer depletion due to increased ground water use in New York currently is being reviewed and addressed by the DEC. The Department's Division of Water's Pump Test Procedures for Water Supply Applications in conjunction with the SRBC's aquifer testing protocol will be used to evaluate proposed groundwater withdrawals for high-volume hydraulic fracturing.

7.1.1.2 Other Jurisdictions - Great Lakes-St. Lawrence River Water Resources Compact

The recently enacted Great Lakes-St. Lawrence River Water Resources Compact prohibits the bulk transport of water from that basin in containers larger than 5.7 gallons.[1] In addition, effective December 8, 2008, the Great Lakes-St. Lawrence River Basin Water Resources Compact ("Compact")[5] prohibits any new or increased diversion of any amount of water out of the Great Lakes Basin with certain limited exceptions. Also under the Compact, any proposed new or increased withdrawal of surface or groundwater that will result in a consumptive use of 5 million gallons per day or greater averaged over a 90-day period requires prior notice and consultation with the Great Lakes-St. Lawrence River Basin Water Resources Council and the Canadian Provinces of Ontario and Quebec.

Once New York establishes legislation to implement the Compact, all new and increased water withdrawals must comply with the Compact's Decision-Making Standard, Section 4.11, which establishes five criteria all water withdrawal proposals must meet, including:

1) The return of all water not otherwise consumed to the source watershed;

[5] Title 10 of ECL Article 21

2) No significant adverse individual or cumulative impacts shall to the quantity of the waters and water-dependent natural resources;

3) Implementation of environmentally sound and economically feasible water conservation measures shall be implemented;

4) Compliance with all other applicable federal, state, and local laws as well as international agreements and treaties; and

5) Reasonable proposed use of water.

However, until New York establishes implementing legislation and regulations under the Compact, existing requirements for the registration of major withdrawals and diversion approval remain in effect under ECL Article 15, Title 16.

The Great Lakes Commission does not have regulatory authority similar to that held by Susquehanna River Basin Commission (SRBC) and Delaware River Basin Commission (DRBC) to review water withdrawals and uses and require mitigation of environmental impacts. However, the new Great Lakes-St. Lawrence River Water Resources Council has specific authority for the review and/or approval of certain new and increased water withdrawals. Review by the Compact Council will require compliance with the Compact's Decision-Making Standard and Standard for Exceptions.

7.1.1.3 Other Jurisdictions - River Basin Commissions

The Susquehanna River Basin Commission (SRBC) and the Delaware River Basin Commission (DRBC) are interstate compact entities with authority over certain water uses within discrete portions of the State. New York is a member of the Board of these river basin commissions. Those commissions with regulatory programs which address water withdrawals are described below, and mitigation measures provided by those programs are incorporated into subsequent sections.

Table 7.1 is a summary of relevant regulations for each of the governmental bodies with jurisdiction over issues related to water withdrawals. Surface water withdrawals in excess of 100,000 gpd require the approval of the SRBC and DRBC within their respective river basins. In response to increased gas drilling in Pennsylvania, SRBC has recently amended its regulations to further address gas drilling withdrawals and consumptive use. In addition to surface water withdrawals, SRBC and DRBC control diversions of water into and out of their respective basins. While ECL 15-1505 prohibits transport of water out of New York State via pipes, canals or streams without a permit from the Department, it does not specifically prohibit such transport by tanker truck. Neither SRBC nor DRBC control transfers of water from state-to-state within their basins.

Delaware River Basin Commission Jurisdictions

Degradation of a Stream's Use - Section 3.8 of the DRBC's Compact states "No project having a substantial effect on the water resources of the basin shall hereafter be undertaken by any person, corporation or governmental authority unless it shall have been first submitted to and approved by the Commission, subject to the provisions of Sections 3.3 and 3.5. The Commission shall approve a project whenever it finds and determines that such project would not substantially impair or conflict with the Comprehensive Plan and may modify and approve as modified, or may disapprove any such project whenever it finds and determines that the project would substantially impair or conflict with such Plan". DRBC regulations work collectively to protect Delaware River Basin streams from sources of degradation that would affect the best

Table 7.1 - Regulations Pertaining to Watershed Withdrawal

Agency	Potential Impacts of Reduced Stream Flow	Denigration of Stream's Designated Best Use	Potential Impacts to Downstream Wetlands	Potential Impacts to Fish and Wildlife	Potential Aquifer Depletion
DRBC	Water Code §2.50.2.A Water Code §2.1.1 Water Code §2.5	Water Code, 18 CFR §410 DRBC Compact	Water Code §2.350	Water Code §2.1.1 Water Code §2.200.1 Water Code §3.10.2.B Water Code §3.10.3.A.2 Water Code §3.10.3.A.2.e Water Code §3.30.4.A.1 Water Code §2.1.2 Water Code §3.10.3.A.2.b Water Code 3.20 Water Code 3.30 Water Code 3.40 Water Code 3.30.4.A.1	Water Code §2.50.2.A Water Code §2.20
NYSDEC	6 NYCRR §675 6 NYCRR §605 6 NYCRR §666	6 NYCRR §608 6NYCRR §666	6 NYCRR §663 6 NYCRR §664 6 NYCRR §665	6 NYCRR §595 6 NYCRR §608 6NYCRR §666	Env. Conservation Law §15-15 Env. Conservation Law §15-1528 6 NYCRR §666
SRBC	Reg. of Projects §806.30 Reg. of Projects §801.3 Reg. of Projects §806.23	Reg. of Projects, 18 CFR §801, §806, §807, §808	Reg. of Projects §801.8 Reg. of Projects §806.14	Reg. of Projects §806.23.b.2 Policy 2003_1 Reg. of Projects §801.9 Reg. of Projects §806.14.b.1.v.C	Reg. of Projects §806.23.b.2 Reg. of Projects §806.12 Reg. of Projects §806.22

usage. The DRBC Water Code[6] provides the regulations, requirements, and programs enacted into law that serve to facilitate the protection of these water resources in the Basin.

Reduced Stream Flow - Potential impacts of reduced stream flow associated with shale gas development by high-volume hydraulic fracturing in the Delaware River Basin are under the purview of the DRBC. The DRBC has the authority to regulate and manage surface and ground water quantity-related issues throughout the Delaware River Basin. The DRBC requires that all gas well development operators complete an application for water use that will be subject to Commission review. The DRBC primarily uses the following regulations, procedures and programs to address potential impacts of reduced stream flow associated with a water taking:

- Allocation of water resources, including three major reservoirs for the New York City Water supply;
- Reservoir release targets to maintain minimum flows of surface water;
- Drought management including water restrictions on use, and prioritizing water use;
- Water conservation program;
- Passby flow requirements;
- Monitoring and reporting requirements;
- Aquifer testing protocol.

Impacts to Aquatic Ecosystems - DRBC regulations concerning the protection of fish and wildlife are located in the Delaware River Basin Water Code [7]. In general, DRBC regulations require that the quality of waters in the Delaware basin be maintained "in a safe and satisfactory condition…for wildlife, fish, and other aquatic life" (DRBC Water Code, Article 2.200.1).

One of the primary goals of the DRBC is basin-wide water conservation, which is important for the sustainability of aquatic species and wildlife. Article 2.1.1 of the Water Code provides the basis for water conservation throughout the basin. Under Section A of this Article, water

---

[6] 18 CFR Part 410

[7] 18 CFR Part 410

conservation methods will be applied to, "reduce the likelihood of severe low stream flows that can adversely affect fish and wildlife resources." Article 2.1.2 outlines general requirements for achieving this goal, such as increased efficiency and use of improved technologies or practices.

All surface waters in the Delaware Basin are subject to the water quality standards outlined in the Water Code. The quality of Basin waters, except intermittent streams, is required by Article 3.10.2B to be maintained in a safe and satisfactory condition for wildlife, fish and other aquatic life. Certain bodies of water in the Basin are classified as Special Protection Waters (also referred to as Outstanding Basin Waters and Significant Resource Waters) and are subject to more stringent water quality regulations. Article 3.10.3.A.2 defines Special Protection Waters as having especially high scenic, recreational, ecological, and/or water supply values. Per Article 3.10.3.A.2.b, no measureable change to existing water quality is permitted at these locations. Under certain circumstances wastewater may be discharged to Special Protection Areas within the watershed; however, it is discouraged and subject to review and approval by the Commission. These discharges are required to have a national pollutant discharge elimination system (NPDES) permit. Non-point source pollution within the Basin that discharges into Special Protection Areas must submit for approval a Non-Point Source Pollution Control Plan.[8]

Interstate streams (tidal and non-tidal) and groundwater (basin wide) water quality parameters are specifically regulated under the DRBC Water Code Articles 3.20, 3.30, and 3.40, respectively. Interstate non-tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident game fish and other aquatic life, maintenance and propagation of trout, spawning and nursery habitat for anadromous fish, and wildlife. Interstate tidal streams are required to be maintained in a safe and satisfactory condition for the maintenance and propagation of resident fish and other aquatic life, passage of anadromous fish, and wildlife. Groundwater is required to be maintained in a safe and satisfactory condition for use as a source of surface water suitable for wildlife, fish and other aquatic life. It shall be "free from substances or properties in concentrations or combinations

[8] DRBC Water Code, Article 3.10.3.A.2.e

which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, or odor of the waters."[9]

Impacts to Wetlands - DRBC regulations concerning potential impacts to downstream wetlands are located in the Delaware River Basin Water Code[10] addressed under Article 2.350, Wetlands Protection. It is the policy of the DRBC to support the preservation and protection of wetlands by:

1) Minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands;

2) Safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation;

3) Preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and

4) Preventing destructive construction activities generally.

Item 1 directly addresses wetlands downstream of a proposed water withdrawal.

The DRBC reviews projects affecting 25 acres or more of wetlands[11] . Projects affecting less than 25 acres are reviewed by the DRBC only if no state or federal review and permit system is in place, and the project is determined to be of major significance by the DRBC. Additionally, the DRBC will review state or federal actions that may not adequately reflect the Commission's policy for wetlands in the basin.

Aquifer Depletion - DRBC regulations concerning the mitigation of potential aquifer depletion are located in the Delaware River Basin Water Code (18 CFR Part 410). The protection of underground water is covered under Section 2.20 of the DRBC Water Code. Under Section 2.20.2, "The underground water-bearing formations of the Basin, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected". Projects that withdraw underground waters must be planned and operated in a manner which will reasonably

[9] DRBC Water Code, Article 3.30.4.A.1

[10] 18 CFR 410

[11] DRBC Water Code, Article2.350.4

safeguard the present and future groundwater resources of the Basin. Groundwater withdrawals from the Basin must not exceed sustainable limits. No groundwater withdrawals may cause an aquifer system's supplies to become unreliable, or cause a progressive lowering of groundwater levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows or perennial streams (DRBC Water Code, Article 2.20.4) Additionally, "The principal natural recharge areas through which the underground waters of the Basin are replenished shall be protected from unreasonable interference with their recharge function" (DRBC Water Code, Article 2.20.5).

The interference, impairment, penetration, or artificial recharge of groundwater resources in the basin are subject to review and evaluation by the DRBC. All owners of individual wells or groups of wells that withdraw an average of 10,000 gallons per day or more during any 30-day period from the underground waters of the Basin must register their wells with the designated agency of the state where the well is located. Registration may be filed by the agents of owners, including well drillers. Any well that is replaced or re-drilled, or is modified to increase the withdrawal capacity of the well, must be registered with the designated state agency (Delaware Department of Natural Resources and Environmental Control; New Jersey Department of Environmental Protection; New York State Department of Environmental Conservation; or the Pennsylvania Department of Environmental Protection) (DRBC Water Code, Article 2.20.7).

Groundwater withdrawals from aquifers in the Basin that exceed 100,000 gallons per day during any 30-day period are required be metered, recorded, and reported to the designated state agencies. Withdrawals are to be measured by means of an automatic continuous recording device, flow meter, or other method, and must be measured to within five percent of actual flow. Withdrawals must be recorded on a biweekly basis and reported as monthly totals annually. More frequent recording or reporting may be required by the designated agency or the DRBC (DRBC Water Code, 2.50.2.A).

Susquehanna River Basin Commission Jurisdictions

Degradation of a Stream's Use - The SRBC has been granted statutory authority to regulate the conservation, utilization, development, management, and control of water and related natural resources of the Susquehanna River Basin and the activities within the basin that potentially affect those resources. The SRBC controls allocations, diversions, withdrawals, and releases of water in the basin to maintain the appropriate quantity of water. The SRBC Regulation of Projects[12] provides the details of the programs and requirements that are in effect to achieve the goals of the commission.

Reduced Stream Flow - The SRBC has the authority to regulate and manage surface and ground water withdrawals and consumptive use in the Susquehanna River Basin. The SRBC requires that all gas well development operators complete an application for water use that will be subject to Commission review. The SRBC primarily uses the following regulations, procedures and programs to address potential impacts of reduced stream flow associated with a water taking:

- Consumptive use regulations;
- Mitigation measures;
- Conservation measures and water use alternatives;
- Conservation releases;
- Evaluation of safe yield (7-day, 10-year low flow);
- Passby requirements;
- Monitoring and reporting requirements;
- Aquifer testing protocol.

Impacts to Aquatic Ecosystems -SRBC regulations concerning the protection of fish and wildlife are located in the Susquehanna River Basin Commission Regulation of Projects [13]. In general, the Commission promotes sound practices of watershed management for the purposes of improving fish and wildlife habitat (SRBC Regulation of Projects, Article 801.9).

Projects requiring review and approval of the SRBC under §§ 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on fish and wildlife (SRBC Regulation of

[12] 18CFR, Parts 801, 806, 807, and 808

[13] 18 CFR Parts 801, 806, 807, and 808

Projects, Article 806.14.b.1.v.C). "The Commission may deny an application, limit or condition an approval to ensure that the withdrawal will not cause significant adverse impacts to the water resources of the basin."[14] The Commission considers water quality degradation affecting fish, wildlife or other living resources or their habitat to be grounds for application denial.

Water withdrawal from the Susquehanna River Basin is governed by passby flow requirements that can be found in the SRBC Policy Document 2003-1, "Guidelines for Using and Determining Passby Flows and Conservation Releases for Surface-water and Ground-water Withdrawal Approvals." A passby flow is a prescribed quantity of flow that must be allowed to pass a prescribed point downstream from a water supply intake at any time during which a withdrawal is occurring. The methods by which passby flows are determined for use as impact mitigation are described below.

Impacts to Wetlands - Projects requiring review and approval of the SRBC under §§ 806.4, 806.5, or 806.6 are required to submit to the Commission a water withdrawal application. Applications are required to contain the anticipated impact of the proposed project on surface water characteristics, and on threatened or endangered species and their habitats.[15]

Aquifer Depletion - Evaluation of ground water resources includes an aquifer testing protocol to evaluate whether well(s) can provide the desired yield and assess the impacts of pumping. The protocol includes step drawdown testing and a constant rate pumping test. Monitoring requirements of ground water and surface water are described in the protocol and analysis of the test data is required. This analysis typically includes long term yield and drawdown projection and assessment of pumping impacts.

7.1.1.4 Impact Mitigation Measures for Surface Water Withdrawals

Delaware River Basin Commission Method

DRBC has the charge of conserving water throughout the Delaware basin by reducing the likelihood of severe low stream flows that can adversely affect fish and wildlife resources and

[14] SRBC Regulation of Projects, Article 806.23.b.2

[15] SRBC Regulation of Projects, Article 806.14

recreational enjoyment (18 CFR Part 410, section 2.2.1). The DRBC currently has no specific passby regulation or policy. Prescribed reservoir releases play an important role in Delaware River flow. The DRBC uses a Q7-10 flow for water resource evaluation purposes. The Q7-10 flow is the drought flow equal to the lowest mean flow for seven consecutive days, that has a 10-year recurrence interval.

The Q7-10 is a flow statistic developed by sanitary engineers to simulate drought conditions in water quality modeling when evaluating waste load assimilative capacity (e.g., for point sources from waste water treatment plants). Q7-10 is not meant to establish a direct relation between Q7-10 and aquatic life protection.[16] For most streams, the Q7-10 flow is less than 10% of the average annual flow and may result in degradation of aquatic communities if it becomes established as the only flow protected in a stream.[17]

Susquehanna River Basin Commission Method

The SRBC requires that passby flows, prescribed quantities of flow that must be allowed to pass a prescribed downstream point, be provided as mitigation for water withdrawals. This requirement is prescribed in part to conserve fish and wildlife habitats. "Approved surface-water withdrawals from small impoundments, intake dams, continuously flowing springs, or other intake structures in applicable streams will include conditions that require minimum passby flows. Approved ground water withdrawals from wells that, based on an analysis of the 120-day drawdown without recharge, impact streamflow, or for which a reversal of the hydraulic gradient adjacent to a stream (within the course of a 48-hour pumping test) is indicated, also will include conditions that require minimum passby flows."[18] There are three exceptions to the required passby flow rules stated above:

1) If the surface-water withdrawal or groundwater withdrawal impact is minimal in comparison to the natural or continuously augmented flows of a stream or river, no passby flow will be required. Minimal is defined by SRBC as 10

[16] Camp, Dresser and McKee 1986

[17] Tennant 1976a,b

[18] SRBC, Policy 2003-01

percent or less of the natural or continuously augmented 7-day, 10-year low flow (Q7-10) of the stream or river.

2) For projects requiring Commission review and approval for an existing surface-water withdrawal where a passby flow is required, but where a passby flow has historically not been maintained, withdrawals exceeding 10 percent of the Q7-10 low flow will be permitted whenever flows naturally exceed the passby flow requirement plus the taking. Whenever stream flows naturally drop below the passby flow requirement plus the taking, both the quantity and the rate of the withdrawal will be reduced to less than 10 percent of the Q7-10 low flow.

3) If a surface-water withdrawal is made from one or more impoundments (in series) fed by a stream, or if a ground-water withdrawal impacts one or more impoundments fed by a stream, a passby flow, as determined by the criteria discussed below or the natural flow, whichever is less, will be maintained from the most downstream impoundment at all times during which there is inflow into the impoundment or series of impoundments.

In cases where passby flow is required, the following criteria are to be used to determine the appropriate passby flow for SRBC-Classified Exceptional Value (EV) Waters, High Quality (HQ) Waters, and Cold-Water Fishery (CWF) Waters; For EV Waters, withdrawals may not cause greater than five percent loss of habitat. For HQ Waters, withdrawals may not cause greater than five percent loss of habitat as well; however, a habitat loss of 7.5 percent may be allowed if:

1) The project is in compliance with the Commission's water conservation regulations of Section 804.20;

2) No feasible alternative source is available; and

3) Available project sources are used in a program of conjunctive use approved by the Commission, and combined alternative project source yields are inadequate.

For Class B[19], CWF Waters, withdrawals may not cause greater than a 10 percent loss of habitat. For Classes C and D, CWF Waters, withdrawals may not cause greater than a 15 percent loss of habitat. For areas of the Susquehanna River Basin not covered by the above regulations, the following shall apply:

[19] Water classifications referenced in this section are those established by State of PA which are not equivalent to NYS stream classifications

1) On all EV and HQ streams, and those streams with naturally reproducing trout populations, a passby flow of 25 percent of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made.

2) On all streams not covered in Item 1 above and which are not degraded by acid mine drainage, a passby flow of 20 percent of average daily flow will be maintained downstream from the point of withdrawal whenever withdrawals are made. These streams generally include both trout stocking and warm-water fishery uses.

3) On all streams partially impaired by acid mine drainage, but in which some aquatic life exists, a passby flow of 15 percent of ADF will be maintained downstream from the point of withdrawal whenever withdrawals are made.

4) Under no conditions shall the passby flow be less than the Q7-10 flow.

Natural Flow Regime Method

The "Natural Flow Regime Method" is an alternative to the DRBC and SRBC methods and establishes a passby flow designed to avoid significant adverse environmental impacts from withdrawals for high-volume hydraulic fracturing; specifically impacts associated with: degradation of a stream's best use and reduced stream flow including impacts to aquatic habitat and aquatic ecosystems.

To assure adequate surface water flow, water withdrawals must provide for a passby flow in the stream, as defined above. In general, when streamflow data exist for the proposed withdrawal location, the passby flow is calculated for each month of the year using a combination of 30% of Average Daily Flows (ADF), <u>and</u> 30% of Average Monthly Flows, (AMF). For any given month, the minimum passby flow must be the greater of either the 30% ADF **<u>or</u>** 30% AMF flow.

The purpose of the "Natural Flow Regime Method" is to provide seasonally adjusted instream flows that maintain the natural formative processes of the stream while requiring only minimal to moderate effort to calculate. Once adequate streamflow records are obtained, ADF is easily calculated. The foundation of the "Natural Flow Regime Method" is based on work of Tennant[20] using percentages of average daily flow (ADF) derived from estimated or recorded hydrologic records, limited field measurements, and photographs taken at multiple discharges. The basic

[20] Tennant 1972, 1975, 1976a,b

assumption of the method is that varying flows based on percentages of ADF or AMF are appropriate for maintaining differing levels of habitat quality within the stream and that the time periods for providing different levels of flow are appropriate based on life stage needs of the aquatic biota. Natural hydrologic variability is used as a surrogate for biological, habitat, and use parameters including: depth, width, velocity, substrate, side channels, bars and islands, cover, migration, temperature, invertebrates, fishing and floating, and aesthetics.

The “Natural Flow Regime Method” approach to passby flow is to retain naturalized annual stream flow patterns (hydrographs) and otherwise, avoid non-naturalized flows that may degrade stream conditions and result in adverse impacts.[21] Tennant never intended users to select only one flow throughout the year (e.g., 20% ADF) because using a single flow would not reflect seasonal patterns in hydrology. Tessmann[22] and others [23] adapted Tennant's seasonal flow recommendations to calibrate the percentages of ADF to local hydrologic and biologic conditions including monthly variability based on average monthly flow (AMF).

The “Natural Flow Regime Method” described here has adopted and refined these recommendations to provide for different flows on a monthly basis. The result is that passby flows calculated under this method follow the natural hydrograph, including flushing flows that define and maintain the stream habitat suitable for aquatic biota. Research by Estes[24] and Reiser et al.[25] supports the need for these channel-maintaining flows.

There are certain limitations associated with the “Natural Flow Regime Method” that must be considered, as it assumes a relationship to the stream biology. Data on historic stream flows must be of a sufficient duration and quality to represent the natural flow regimes of the stream[26] as prescriptions for passby flows are only as good as the hydrologic records on which they are based. Beyond concerns over the quality of available hydrologic data, data that are not based on

---

[21] IFC 2004

[22] Tessmann 1980

[23] Estes 1984, 1998

[24] Estes 1984

[25] Reiser et al. 1988

[26] Estes 1998

natural flow conditions (e.g., releases from dams) will influence the calculation of pass by flows and may not support fishery management objectives.

The following considerations regarding the quality of the streamflow data to be used for a proposed water withdrawal location should be applied for each withdrawal (also see Table 7.1 below):

- If the proposed water withdrawal site is in close proximity to an existing USGS gauge location, with at least 10 recent years of continuous daily flow monitoring data, regardless of drainage basin size, then the passby flow can be calculated which incorporates the appropriate ADF and AMF values.

- If the proposed water withdrawal site is within the same drainage as a USGS gauge location possessing 10 recent years or more of continuous daily flow monitoring data , but sources of inflow exist between the two locations then either of the following criteria apply regardless of drainage basin size:

    - When the gauge is located upstream from the withdrawal location, the gauge data must be appropriately adjusted to account for the percent increase in the drainage area at the withdrawal location. (Example: If the drainage area at gauge is 250 square miles and the drainage area at the withdrawal point is 300 square miles, then the data statistics from the gauge would be multiplied by 1.2 for determining passby flows at the withdrawal site.), OR

    - When the gauge is located downstream from the withdrawal location, the gauge data must be appropriately adjusted to account for the percent decrease in the drainage area at the withdrawal location. (Example: If the drainage area at gauge is 250 square miles and the drainage area at the withdrawal point is 200 square miles, then the data statistics from the gauge would be multiplied by 0.8 for determining passby flows at the withdrawal site.)

- If the proposed water withdrawal site is located in a drainage that does not possess a USGS source of streamflow data, then streamflow data can be developed from surrogate streams that have USGS gauging. Surrogate streams should have similar drainage characteristics to the stream where the withdrawal is proposed.

- If the proposed water withdrawal site is located in a drainage basin that is not capable of being represented by a surrogate stream that possesses USGS streamflow data, then the passby flow shall be determined as follows:

  The Aquatic Base Flow method should be used where the passby flow is based on the drainage basin size where:

- from June 1 through October 31, 0.5 cfs/mi^2 of drainage area should be provided, and
- from November 1 through May 31, 1.0 cfs/mi^2 of drainage area should be provided.

For trout waters (i.e protected streams possessing a NY State water quality classification or standard with a (t) or (ts) designation), 4.0 cfs/mi^2 of drainage area during the spring (March 1 through May 31) should be provided. As a general rule, streams having a drainage area of less than 100 square miles may not have suitable surrogates available from which to obtain appropriate streamflow data.

Table 7.2 - Methods for Determination of Passby Flow Based on Data Availability

Data Availability	**Method for Determination of Passby Flow**	
For locations where at least 10 recent years of gauging data are available	A passby flow shall be calculated for each month of the year using a combination of 30% of Average Daily Flows (ADF), and 30% of Average Monthly Flows, (AMF). For any given month the proposed passby flow must be the greater of either the 30% ADF or 30% AMF Flow.	
For locations where less than 10 recent years of gauging data are available	0.5 cfs/mi^2 of drainage area during summer	1.0 cfs/mi^2 of drainage area during winter
In addition, for locations known to support trout, where less than 10 recent years of gauging data are available	4.0 cfs/mi^2 of drainage area during the spring (March 1 through May 31)	

7.1.1.5 Cumulative Water Withdrawal Impacts

The SRBC (February, 2009) stated that "the cumulative impact of consumptive use by this new activity (natural gas development), while significant, appears to be manageable with the mitigation standards currently in place." The extent of the gas-producing shales in New York extends beyond the jurisdictional boundaries of the SRBC and the DRBC. The potential exists for gas drilling and associated water withdrawal to occur outside of the Susquehanna and Delaware River Basins. New York State regulations do not address water quantity issues in a manner consistent with those applicable within the Susquehanna and Delaware River Basins with respect to controlling, evaluating, and monitoring surface water and ground water withdrawals for shale gas development. The application of the Natural Flow Regime Method to all surface water withdrawals to support the subject hydraulic fracturing operations is an option to comprehensively address cumulative impacts on stream flows. Adverse cumulative impacts could be addressed by the Natural Flow Regime Method described above if each operator of a permitted surface water withdrawal estimated or reported the maximum withdrawal rate and measured the actual passby flow for any period of withdrawal. This is because the stream gauge measurements which govern the pass by flow calculation reflect the natural hydrograph of an unregulated stream and do not take into account pre-existing or upstream withdrawals.

7.1.2 Stormwater

The principal control mechanism to mitigate negative impacts from stormwater runoff is to develop, implement and maintain comprehensive Stormwater Pollution Prevention Plans (SWPPP). These plans address the often significant impacts of erosion, sedimentation, peak flow increase, contaminate discharge and nutrient pollution that is associated with industrial activity, including construction projects. Such concerns are raised with the excavation necessary to support the access roads, drill pads, impoundments, staging areas, and pipeline routes associated with the subject operations. This is commonly conducted through the administration of the NYSDEC general permits for stormwater runoff, which require operators to develop, implement and maintain up-to-date SWPPPs. To assist this effort, the NYSDEC has produced technical criteria for the planning, construction, operation and maintenance of stormwater control practices and procedures, including temporary, permanent, structural and non-structural measures. Copies of the general permits and technical guidance can be found on the NYSDEC website at http://www.dec.ny.gov/chemical/8468.html. These controls are Clean Water Act permits required pursuant to the Act and underlying EPA regulations.

A successful SWPPP employs fairly simple concepts aimed at preventing erosion and maintaining post-development runoff characteristics in roughly the same manner as the pre-development condition. Many adverse impacts may be avoided by planning a development to fit site characteristics, like avoiding steep slopes and maintaining sufficient separation from environmentally sensitive features, such as streams and wetlands. Another basic principal is to divert uncontaminated water away from excavated or disturbed areas. In addition, limiting the amount of exposed soil at any one time, stabilizing disturbed areas with mulch and seed as soon as possible, and following equipment maintenance, rapid spill cleanup and other basic good housekeeping measures will act to minimize potential impacts. Lastly, measures to treat stormwater and control runoff rates are used.

A comprehensive SWPPP that is well developed, implemented, maintained and adapted to changing circumstances in strict compliance with the DEC general permit and associated technical standards should effectively act to heighten the beneficial aspects of stormwater runoff while minimizing its potential deleterious impacts.

The Department has determined that natural gas well development using high-volume hydraulic fracturing is eligible for inclusion in Sector AD of the Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (GP-0-06-002) (MGSP).[27] The Department is proposing the option of amending this Multi-Sector General Permit to address a number of potential pollutant discharges associated with the subject operations. As discussed below, the Department is proposing a method to terminate the application of the MSGP after completion of major operations.

7.1.2.1 Construction Activities

In order to facilitate the permitting process for activities addressed by this Supplement, the requirements associated with the General Permit for Stormwater Discharges Associated with Construction Activities (Construction General Permit) will be incorporated into Sector AD of the MGSP as it applies to the subject operation.

[27] http://www.dec.ny.gov/chemical/9009.html

A SWPPP, meeting or exceeding the requirements of the Construction General Permit, must be developed as a stand-alone document and incorporated, by reference, in a comprehensive SWPPP. The SWPPP will address all phases and elements of the activity, including all land clearing and access road, well pad and impoundment construction and apply during all hydraulic fracturing and flowback operations at a well pad. SWPPPs shall be prepared in accordance with good engineering practices and DEC's General Permit for Construction Activity.

Inspections and documentation of inspections must be initiated upon commencement of construction activities and continue until coverage under the MSGP has been appropriately terminated.

7.1.2.2 Industrial Activities

The MSGP will be revised as necessary to incorporate a required SWPPP for industrial activities to address potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges associated with industrial activity from Marcellus Shale and other low-permeability gas reservoir hydraulic fracturing operations. In addition, the comprehensive SWPPP shall describe and ensure the implementation of Best Management Practices (BMPs) which are to be used to reduce the pollutants in stormwater discharges associated with industrial activity at the facility and to ensure compliance with the terms and conditions of the MSGP. Structural, nonstructural and other BMPs must be considered in the SWPPP. Structural BMPs include features such as dikes, swales, diversions, drains, traps, silt fences and vegetative buffers. Nonstructural BMPs include good housekeeping, sheltering activities to minimize exposure to precipitation to the extent practicable, preventative maintenance, spill prevention and response procedures, routine facility inspections, employee training and use of designated vehicle and equipment storage or maintenance areas with adequate stormwater controls. A copy of the SWPPP must be kept on site and available to Department inspectors while permit coverage is in effect.

Monitoring and reporting, in addition to construction related inspections and reports, includes quarterly visual monitoring, an annual dry weather flow inspection, annual site compliance evaluation and annual benchmark monitoring and analysis. Quarterly visual monitoring must commence with construction. Benchmark monitoring must be completed while hydraulic fracturing operations are being conducted or, if no qualifying storms occurred during hydraulic fracturing operations, during the first qualifying storm event thereafter.[28] Sites active for less than one year must satisfy all annual reporting requirements within the period of activity.

MSGP coverage may be terminated upon completion of all drilling and hydraulic fracturing operations, fracturing flowback operations and partial site reclamation. Partial site reclamation has occurred when the Department determines that drilling and fracturing equipment has been removed, pits used for those operations have been reclaimed and surface disturbances not associated with production activities have been re-graded and seeded, and vegetation cover reestablished, and post-construction management practices are fully operational. Operators may, however, elect to maintain coverage if they so choose. In addition, coverage must be maintained if it is otherwise required under the Clean Water Act.

7.1.3 Surface Spills and Releases at the Well Pad

A combination of existing Department tools, enhanced as necessary to address unique aspects of multi-well pad development and high-volume hydraulic fracturing, will be required in appropriate permits to prevent spills and mitigate adverse impacts from any that do occur. Activities and materials on the well pad of concern with respect to potential surface and groundwater impacts from unmitigated spills and releases include the following:

- drilling rig fuel tank and tank refilling activities,
- drilling fluids,
- hydraulic fracturing additives, and
- flowback water.

The proposed spill prevention and mitigation measures advanced herein reflect consideration of the following information reviewed by Department staff:

- The 1992 GEIS and its Findings;

[28] A qualifying storm is one greater than 0.1 inch in magnitude that occurs at least 72 hours from the previously measurable (>0.1 inch rainfall) storm event.

- GWPC, 2009b:
- Alpha, 2009, regarding:
    - a survey of regulations related to natural gas development activities in Pennsylvania, Colorado, New Mexico, Wyoming , Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas;
    - materials handling and transport requirements, including USDOT and NYSDOT regulations, NYSDEC Bulk Storage Programs and USEPA reporting requirements; and
    - specific recommendations for minimizing potential liquid chemical spills;
- Guidance documents relative to the Department's Petroleum Bulk Storage Program, including:
    - Spill Prevention Operations Technology Series (SPOTS) 10, Secondary Containment Systems for Aboveground Storage Tanks,[29] and
    - Draft DEC Program Policy DER-17[30];
- SWPPP guidance compiled by the Department's Division of Water;
- US Department of the Interior and US Department of Agriculture, 2007; and
- An industry Best Management Practices (BMP) manual provided to the Department.

7.1.3.1 Drilling Rig Fuel Tank and Tank Refilling Activities

The diesel tank associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank is removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fuel tank. Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements. The following measures will be implemented to mitigate spills:

[29] http://www.dec.ny.gov/docs/remediation_hudson_pdf/spots10.pdf

[30] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf

1) The EAF Addendum will require information regarding the capacity and planned well pad location of rig fuel tanks and distance to any primary or principal aquifer, public or private water well, domestic-supply spring, reservoir, reservoir stem, controlled lake, watercourse, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned tank location. To the extent practical, the Department will encourage operators to position the tank more than 500 feet from these water resources.

2) For multi-well pads, supplementary permit conditions for high-volume hydraulic fracturing will include the following requirements:

    a. Secondary containment consistent with the objectives SPOTS 10 for all tanks larger than 10,000 gallons and for smaller tanks if the tank will be positioned within 500 feet of a primary or principal aquifer, public or private water well, a domestic-supply spring, a reservoir, reservoir stem or controlled lake, watercourse, perennial or intermittent stream, storm drain, wetland, lake or pond.

       The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, impoundments, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel. Soil that is used for secondary containment should be of such character that a spill into the soil will be readily recoverable and will result in a minimal amount of soil contamination and infiltration. Draft DEC Program Policy DER-17[31] may be consulted for permeability criteria for dikes and impoundment floors and dike construction standards, including capacity of at least 110% of the tank's volume.

       Implementation of secondary containment and permeability criteria is consistent with GWPC's recommendations.

    b. Tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck.

    c. Troughs, drip pads or drip pans will be required beneath the fill port of the tank during filling operations if the fill port is not within the secondary containment.

3) The comprehensive Stormwater Pollution Prevent Plan (SWPPP) that is required by the Department's Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (GP-0-06-002) (MSGP) will include Best Management Practices to minimize or eliminate pollutants in stormwater. Such BMPs include, but are not limited to, a combination of some or all of the following, or other equally protective practices:

    a. Identification of a spill response team and employee training on proper spill prevention and response techniques,

[31] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf

b. Inspection and preventative maintenance protocols for the tank(s) and fueling area,

c. Procedures for notifying appropriate authorities in the event of a spill,

d. Procedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete,

e. Ready availability of appropriate spill containment and clean-up materials and equipment, including oil-containment booms and absorbent material,

f. Disposal of cleanup materials in the same manner as the spilled material,

g. Use of dry cleanup methods and non-use of emulsifiers or dispersants,

h. Protocols for checking/testing stormwater in containment area prior to discharge,

i. Conduct of tank filling operations under a roof or canopy where possible, with the covering extending beyond the spill containment pad to prevent rain from entering,

j. Use of drip pans where leaks or spills could occur during tank filling operations and where making and breaking hose connections,

k. Use of fueling hoses with check valves to prevent hose drainage after spilling,

l. Use of spill and overflow protection devices,

m. Use of diversion dikes, berms, curbing, grading or other equivalent measures to minimize or eliminate run-on into tank filling areas,

n. Use of curbing or posts around the fuel tank to prevent collisions during vehicle ingress and egress, and

o. Availability of a manual shutoff valve on the fueling vehicle.

7.1.3.2 Drilling Fluids

The GEIS describes reserve pits excavated at the well which may contain drill cuttings, drilling fluid, formation water, and flowback water from a single well. As stated in the GEIS:

> Although the existing regulations do mention clay and hardpan as options in pit construction, the Department has consistently required that all earthen temporary drilling pits be lined with sheets of plastic before they can be used. Clay and hardpan are both low in permeability, but they are not watertight. They are also subject to chemical reaction with some drilling and completion fluids. In addition, the time constraints on drilling operations do not allow adequate time for the percolation tests which should be performed to check the permeability of a clay lined pit. Liners for large pits are usually made from several sheets of plastic which should be factory seamed. Careful attention to sealing the seams is extremely important in preventing groundwater contamination; [32]

and:

> Pits for fluids used in the drilling, completion, and re-completion of wells should be constructed, maintained and lined to prevent pollution of surface and subsurface waters and to prevent pit fluids from contacting surface soils or ground water zones. Department field inspectors are of the opinion that adequate maintenance after pit liner installation is more critical to halting pollution than the initial pit liner specifications. Damaged liners must be repaired or replaced promptly. Instead of very detailed requirements in the regulations, the regulatory and enforcement emphasis will be on a general performance standard for initial review of liner-type and on proper liner maintenance.
>
> The type and specifications of the liner proposed by the well drilling applicant will require approval by the DEC Regional Minerals Manager. The acceptability of each proposed pit construction and location should be determined during the pre-site inspection. Any pit site or pit orientation found unacceptable to the Department must be changed as directed by the regional site inspector.[33]

Regulations require that pit fluids must be removed within 45 days of cessation of drilling operations (includes stimulation), “unless the department approves an extension based on circumstances beyond the operator’s control. The Department may also approve an extension if the fluid is to be used in subsequent operations according to the submitted plan, and the department has inspected and approved the storage facilities.” [34]

[32] p. 9-32

[33] p. FGEIS48

[34] 6 NYCRR 554.(1)(c)(3)

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.[35] After the cessation of drilling and/or stimulation operations, pit fluids must be removed within seven days.

Recommended GEIS specifications, and the ultimate decision to use a site and performance-based standard rather than detailed specifications, were largely based upon the short duration of a pit's use. Pits used for more than one well will be used for a longer period of time. "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination."[36] Specifications more stringent than those proposed in the GEIS which relate to durability and longer duration of use are appropriate, and are consistent with GWPC's recommendations (Section 5.18.1.2). Additional protection will be provided by the requirement for an SWPPP and by measuring SEQRA setbacks from the edge of the well pad instead of from the well.

The following measures will be implemented to mitigate the potential for releases associated with the on-site reserve pit:

1) The EAF Addendum will require information about the planned location, construction and capacity of the reserve pit. The Department will not approve reserve pits on the filled portion of cut-and-fill sites.

2) Supplementary permit conditions for multi-well pad high-volume hydraulic fracturing will include the following requirements:

    a. Diversion of surface water and stormwater runoff away from the pit,

    b. Pit volume limit of 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land,

    c. Beveled walls (45 degrees or less) for pits constructed in unconsolidated materials,

    d. Sidewalls and bottoms free of objects capable of puncturing and ripping the liner,

    e. Sufficient slack in liner to accommodate stretching,

[35] Freshwater Aquifer Supplementary Permit Conditions, www.dec.ny.gov/energy/42714.html

[36] GWPC, 2009a. p. 29

f. Minimum 30-mil liner thickness,

g. Liners installed and seamed in accordance with the manufacturer's specifications,

h. Freeboard monitoring and maintenance of 2 feet of freeboard at all times,

i. Fluids removed and pit inspected prior to additional use if longer than a 45-day gap in use, and

j. Fluids removed and pit reclaimed within 45 days of completing drilling and stimulation operations at last well on pad.

2) The following additional or more stringent requirements will be included in well permit conditions for multi-well pad high-volume hydraulic fracturing in primary or principal aquifers areas or unfiltered water supply areas.

   a. Removal of pit fluids within 7 days of drilling/stimulation operations for each well, and inspection by the Department prior to use for the next well;

   b. Immediate removal of pit fluids if operations are suspended and the site is left unattended; and

   c. Removal of pit fluids within 7 days of completing drilling and stimulation operations at last well on pad.

3) The comprehensive SWPPP that is required by the Department's MSGP (GP-0-06-002) will include Best Management Practices relative to reserve pit fluid containment, including, but not limited to, a combination of some or all of the following, or other equally protective practices:

   a. Identification of a spill response team and employee training on proper spill prevention and response techniques,

   b. Inspection and preventative maintenance protocols for the pit walls and liner,

   c. Procedures for immediately notifying appropriate authorities in the event of a significant pit failure resulting in discharge to ground or surface water,

   d. Procedures for immediately repairing the pit or liner and containing the released liquid until cleanup is complete,

   e. Ready availability of appropriate spill clean-up materials and equipment,

   f. Disposal of cleanup materials in the same manner as the spilled material, and

   g. Use of dry cleanup methods, and non-use of emulsifiers or dispersants.

7.1.3.3 Hydraulic Fracturing Additives

Chapter 5 describes the USDOT- or UN-approved containers in which hydraulic fracturing additives are delivered and held until they are mixed with water and proppant and pumped into the well, and also describes the length of time that additives are present on the site. The inherent mitigation factors stated in Section 6.1.11 with respect to the risks presented by high-volume hydraulic fracturing in the New York City Watershed are not unique to that watershed but exist at all locations. Well pad setbacks from water resources described in Section 7.1.12 also apply to all locations. Additional mitigation measures will be implemented as follows:

1) Specific secondary containment requirements will be included in supplementary well permit conditions for high-volume hydraulic fracturing on a site-specific basis if the proposed location or operation raises a concern about potential liquid chemical releases that is not, in the Department's judgment, sufficiently addressed by the GEIS, the SGEIS, inherent mitigation factors and well pad setbacks.

   In this instance, the Department may require the applicant to identify in application materials the anticipated maximum number, type, and volume of liquid fracturing additive containers to be simultaneously present onsite. This is in addition to the fluid disclosure requirements on the EAF Addendum. The Department will evaluate whether those containers could reasonably be anticipated to discharge to surface or ground water, if a spill occurred. The criteria for this evaluation will include consideration of factors such as the nature and classification of the liquid, qualitative soil permeability, relative topographic position, engineered or designed containment controls, or other physical factors specific to the application.[37]

   Secondary containment requirements could include, as deemed appropriate, one or a combination of the following; dikes, liners, pads, holding ponds, impoundments, curbs, ditches, sumps, receiving tanks, or other equipment capable of containing the substance. The secondary containment should be sufficient to contain 110% of the single largest liquid chemical container within a common staging area.

   Supplementary well permit conditions will also require removal of hydraulic fracturing additives from the site if the site will be unattended.

2) The comprehensive SWPPP that is required by the Department's MSGP (GP-0-06-002) will include Best Management Practices relative to additive containers, mixing and pumping, including, but not limited to, a combination of some or all of the following, or other equally protective practices:

[37] Alpha, 2009, section 2.14

a. Identification of a spill response team and employee training on proper spill prevention and response techniques;

b. Location of additive containers and transport, mixing and pumping equipment as follows:

    i. within secondary containment,

    ii. away from high traffic areas,

    iii. as far as is practical from surface waters,

    iv. not in contact with soil or standing water, and

    v. product and hazard labels not exposed to weathering;

c. Use of troughs, drip pads or drip pots under hose connections;

d. Inspection and preventative maintenance protocols for containers, pumping systems and piping systems, including manned monitoring points during additive transfer, mixing and pumping activities;

e. Protocols for ensuring that incompatible materials such as acids and bases are not held within the same containment area;

f. Procedures for notifying appropriate authorities in the event of a spill;

g. Procedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete;

h. Maintenance of a running inventory of additive products present and used on-site;

i. Ready availability of appropriate spill containment and clean-up materials and equipment including absorbent material;

j. Disposal of cleanup materials in the same manner as the spilled material;

k. Use of dry cleanup methods and non-use of emulsifiers or dispersants;

l. Protocols for checking/testing stormwater in any secondary containment area prior to discharge;

m. Use of drip pads or pans where additives and fracturing fluid are transferred from containers to the blending unit, from the blending unit to the pumping equipment and from the pumping equipment to the well;

n. Use of spill and overflow protection devices,;

o. Use of diversion dikes, berms, curbing, grading or other equivalent measures to minimize or eliminate run-on into additive holding, mixing and pumping areas, and

p. Availability of manual shutoff valves.

7.1.3.4 Flowback Water

The GEIS addresses use of the on-site reserve pit for flowback water associated with a single well. However, even in the single-well case, potential flowback water volumes associated with high-volume hydraulic fracturing exceed GEIS descriptions. Estimates provided in Section 5.11.1 are for 216,000 gallons to 2.7 million gallons of flowback water recovered within two to eight weeks of hydraulic fracturing a single well. The volume of flowback water that would require handling and containment on the site is variable and difficult to predict, and data regarding its likely composition are incomplete. Therefore, the Department proposes a requirement that flowback water handled at the well pad be directed to and contained in steel tanks. Even without this requirement, the pit volume limitation proposed above would necessitate that tank storage be available on site. The Department will also continue to encourage exploration of technologies that promote reuse of flowback water when practical. Additional mitigation measures will be implemented as follows:

1) The EAF Addendum will require information about the number, individual and total capacity and location on the well pad of receiving tanks for flowback water.

2) Supplementary permit conditions for high-volume hydraulic fracturing will include the following requirements:

   a. Fluids removed if there will be a hiatus in site activity longer than 45 days,

   b. Fluids removed within 45 days of completing drilling and stimulation operations at last well on pad, and

   c. Fluid transfer operations from tanks to tanker trucks must be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck.

3) The following additional or more stringent requirements will be included in well permit conditions for multi-well pad high-volume hydraulic fracturing in primary or principal aquifers areas or unfiltered water supply areas.

a. Removal of fluids within 7 days of drilling/stimulation operations for each well;

b. Immediate fluid removal if operations are suspended and the site is left unattended at any time; and

c. Removal of fluids within 7 days of completing drilling and stimulation operations at last well on pad.

4) The comprehensive SWPPP that is required by the Department's MSGP (GP-0-06-002) will include Best Management Practices relative to flowback water tanks, including, but not limited to, a combination of some or all of the following, or other equally protective practices:

a. Identification of a spill response team and employee training on proper spill prevention and response techniques,

b. Location of tanks within secondary containment, away from high traffic areas and as far as is practical from surface waters,

c. Protocols for checking/testing stormwater in any secondary containment area prior to discharge,

d. Maintenance of a running inventory of flowback water recovered, present on site, and removed from the site,

e. Use of troughs, drip pads or drip pots under hose connections that are not within secondary containment,

f. Inspection and preventative maintenance protocols for containers, pumping systems and piping systems, including manned monitoring points during initial flowback operations,

g. Inspection and preventative maintenance protocols for the tanks and associated piping, hoses and valves,

h. Procedures for notifying appropriate authorities in the event of a spill,

i. Procedures for immediately repairing any leak or breach and containing the released liquid until cleanup is complete,

j. Ready availability of appropriate spill clean-up materials and equipment,

k. Disposal of cleanup materials in the same manner as the spilled material, and

l. Use of dry cleanup methods, and non-use of emulsifiers or dispersants

7.1.4 Ground Water Impacts Associated With Well Drilling and Construction

Existing construction and cementing practices and permit conditions to ensure the protection and isolation of fresh water will remain in use, and will be enhanced by Supplementary Permit Conditions for High-Volume Hydraulic Fracturing. See Appendices 8, 9 and 10. Based on discussion in Chapters 2 and 6 of this Supplement, along with GWPC's regulatory review,[38] issues associated with well drilling and construction relate to ground water and include the following:

- Baseline water quality testing of private wells within a specified distance of the proposed well;
- Sufficiency of as-built wellbore construction prior to high-volume hydraulic fracturing, including:
    - Adequacy of surface casing to protect fresh water and to isolate potable fresh water supplies from deeper gas-bearing zones,
    - Adequacy of cement in the annular space around the surface casing,
    - Adequacy of cement on production (and intermediate) casing to prevent upward migration of fluids during all reservoir conditions,
    - Use of centralizers to ensure that the cement sheath surrounds the casing strings, and
    - The opportunity for state regulators to witness casing and cementing operations and
- Prevention of pressure build-up in the annular space between the surface casing and intermediate or production casing.

The proposed well construction-related requirements advanced herein reflect consideration of the following information and sources:

- The 1992 GEIS and its Findings;
- The Department's existing required casing and cementing practices (Appendix 8);

[38] GWPC, 2009b

- The Department's existing supplementary freshwater aquifer permit conditions (Appendix 9);

- Harrison, 1984, with respect to the importance of maintaining the surface-production casing annulus in a non-pressurized condition (a preventative measure which has been implemented as part of the Department's required casing and cementing practices since at least 1985);

- DEC Commissioner's Decision, 1985, regarding well casing cement and the requirement to maintain an open annulus to prevent gas migration into aquifers;

- Ohio Department of Natural Resources, 2008, regarding permit conditions developed to prevent over-pressurized conditions in the surface-production casing annulus;

- GWPC, 2009b, well construction recommendations;

- NYSDOH Recommended Residential Water Quality Testing, Individual Water Supply Wells Fact Sheet #3, relative to recommended water quality testing for all wells and recommended additional parameters to test if gas drilling nearby is the reason for water testing;[39]

- NYSDOH recommendations relative to private water well testing dated July 21, 2009, based on review of fracturing fluid constituents and flowback characteristics;

- URS, 2009, water well testing recommendations based on review of fracturing fluid constituents and flowback characteristics;

- Alpha, 2009, regarding:

  - water well testing requirements in other states identified through a survey of regulations in 10 other jurisdictions, and

  - previous drilling in aquifers, watersheds and aquifer recharge areas; and

- ICF, 2009a, regarding:

  - water well testing recommendations and

  - review of hydraulic fracturing design and subsurface fluid mobility.

[39] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs3_water_quality.htm, accessed 9/16/09

7.1.4.1 Private Water Well Testing

Supplementary permit conditions for high-volume hydraulic fracturing will require the sampling and testing of residential water wells within 1,000 feet of the well pad, subject to the property owner's permission, or within 2,000 feet of the well pad if no wells are available for sampling within 1,000 feet either because there are none of record or because the property owner denies permission. All testing and analysis must be by an ELAP-certified laboratory,[40] and the results of each test must be provided to the property owner and the county health department prior to commencing drilling operations.

Schedule

Testing before drilling provides a baseline for comparison in the event that water contamination is suspected. Testing prior to drilling each well at a multi-well pad provides ongoing monitoring between drilling operations, so the requirement will be attached to every well permit that authorizes high-volume hydraulic fracturing. Testing at established intervals after drilling or hydraulic fracturing operations provides opportunities to detect contamination or confirm its absence. If no contamination is detected a year after the last hydraulic fracturing event on the pad, then further routine monitoring should not be necessary. The Department proposes the following ongoing monitoring schedule:

- Initial sampling and analysis prior to site disturbance at the first well on the pad, and prior to drilling commencement at additional wells on multi-well pads;
- Sampling and analysis three months after reaching total measured depth (TMD) at any well on the pad if there is a hiatus of longer than three months between reaching TMD and any other milestone on the well pad that would require sampling and analysis; and
- Sampling and analysis three months, six months and one year after hydraulic fracturing operations at each well on the pad.

For multi-well pads where drilling and hydraulic fracturing activity is continuous, to the extent that water well sampling and analysis according to the above schedule would occur more often than every three months, then the Department proposes to simplify the protocol so that sampling and analysis occurs at three month intervals until six months after the last well on the pad is

[40] http://www.wadsworth.org/labcert/elap/elap.html, accessed 9/16/09

hydraulically fractured, with a final round of sampling and analysis one year after the last well on the pad is hydraulically fractured.

More frequent sampling and analysis, or sampling and analysis beyond one year after last hydraulic fracturing operations, may be warranted in response to complaints as described below.

Parameters

The New York State Department of Health recommends water well testing as set forth in Table 7.1 prior to using a new residential water well. DEC proposes that the same parameters also be tested prior to high-volume hydraulic fracturing, in order to establish a baseline and to ensure that pre-existing conditions are adequately characterized.

Table 7.3 - NYSDOW Water Well Testing Recommendations[41]

Analysis	Recommended MCL[42,43]	Concerns
Coliform Bacteria	Any positive result is unsatisfactory	Indicator of possible disease-causing contamination, e.g. Gastro-intestinal illness
Lead	0.015 mg/l	Brain, nerve and kidney damage (especially in children)
Nitrate	10 mg/l as N	Methemoglobinemia ("blue baby syndrome")
Nitrite	1 mg/l as N	Methemoglobinemia ("blue baby syndrome")
Iron	0.3 mg/l	Rust-colored staining of fixtures or clothes
Manganese	0.3 mg/l	Black staining of fixtures or clothes
Iron plus manganese	0.5 mg/l	Rusty or black staining of fixtures or clothes
Sodium	No designated limit[44]	Effects on individuals with high blood pressure
pH	No designated limit	Pipe corrosion (lead and copper), metallic-bitter taste
Hardness	No designated limit	Mineral and soap deposits, detergents are less effective
Alkalinity	No designated limit	Inhibits chlorine effectiveness, metallic-bitter taste
Turbidity	5 NTU	Cloudy, "piggybacking" of contaminants, interferes with chlorine and UV-light disinfection

Based on recommendations from the sources (including NYSDOH) cited above, that reviewed fracturing additive and flowback water composition data provided to the Department and

[41] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs3_water_quality.htm, accessed 9/16/09

[42] MCL means maximum contaminant level. The MCLs listed are based upon requirements for Public Water Supply systems and are also recommended for use on individual residential systems.

[43] mg/l means milligram per liter (parts per million); NTU means Nephelometric Turbidity Units

[44] Water containing more than 20 mg/l of sodium should not be used for drinking by people on severely restricted sodium diets. Water containing more than 270 mg/l of sodium should not be used by people on moderately restricted sodium diets.

summarized in Chapters 5 and 6, the following additional testing parameters have been identified:

- Static water level
- Total dissolved solids (TDS)
- Total suspended solids (TSS)
- Chlorides
- Carbonates
- Bicarbonates
- Sulfate
- Barium
- Strontium
- Arsenic
- Surfactants
- Methane
- Hydrogen sulfide
- Benzene
- Gross alpha
- Gross beta

Contaminant-indicators should be included in the initial, pre-drilling or baseline round of sampling to ensure that pre-existing conditions are considered in response to complaints of suspected contamination. Of the above parameters, barium, TDS and pH are identified as those which could initially suggest contamination as a result of the fracturing operation. Monitoring for strontium, sodium, chloride, hardness, surfactants, TSS, iron, carbonates and bicarbonates could provide a better understanding of the extent of potential contamination. As diesel-based fracturing fluid is not proposed or reviewed by this Supplement, the primary reason for its inclusion is to indicate above-ground fuel spills.[45] NYSDOH Bureau of Environmental Radiation Protection staff indicates that total gross alpha activity is an inexpensive (but effective) screening tool, and would indicate the need for additional analysis if the value is greater than 15 pCi/L. Analysis of changes in static water level should carefully consider the well's construction, maintenance and operational history, recent precipitation and use patterns, the season and the effects of competing wells.

[45] URS, p. 8-4

Complaints

As noted in the GEIS:

> The diversity of jurisdictions having authority over local water supplies complicates the response to complaints about water supplies, including those complaints that complainants believe are related to oil and gas activity. Water supply complaints occur statewide and take many forms, including taste and turbidity problems, water quantity problems, contamination by salt, gasoline and other chemicals and problems with natural gas in water wells. All of these problems, including natural gas in water supplies, occur statewide and are not restricted to areas with oil and gas development.[46]

and:

> The initial response to water supply complaints is best handled by the appropriate local health office, which has expertise in dealing with water supply problems.[47]

Under the proposed protocols, county health departments will receive the results of baseline testing and ongoing monitoring that occurs until a year after the last hydraulic fracturing operations on a well pad. Therefore, they remain in the best position to investigate initial water well complaints from residential well users. The Department has MOUs in place with several county health departments in western NY whereby the county health department initially investigates a complaint and then refers it to DEC when a problem has been verified and other potential causes have been ruled out. For complaints that occur more than a year after the last hydraulic fracturing operations on a well pad within the radius where baseline sampling occurred (1,000 feet or 2,000 feet), or for complaints regarding water wells that are more than 2,000 feet away from any well pad, the Department proposes to follow this procedure statewide. Complaints would be referred to the county health department, who would refer them back to DEC for investigation when a problem has been verified and other potential causes have been ruled out. Sampling and analysis to verify and evaluate the problem would be according to protocols that are satisfactory to the county health department, with advice from NYSDOH as necessary.

---

[46] GEIS, pp. 15-4 et seq.

[47] GEIS, p. 15-5

Complaints that occur during active operations at a well pad within 2,000 feet or the radius where baseline sampling occurred, or within a year of last hydraulic fracturing at such a site, should be jointly investigated by DEC and the county health department. Mineral Resources staff shall conduct a site inspection, and if a complaint coincides with any of the following documented potentially polluting non-routine well pad incidents, then the Department will consider the need to require immediate cessation of operations, immediate corrective action and/or revisions to subsequent plans and procedures on the same well pad, in addition to any applicable formal enforcement measures:

- Surface chemical spill;
- Fracture equipment failure;
- Observed leaks in surface equipment onto the ground , into stormwater runoff or into a surface waterbody;
- Observed pit liner failure;
- Significant lost circulation or fresh water flow below surface casing;
- The presence of brine, gas or oil zones not anticipated in the pre-drilling prognosis;
- Evidence of a gas-cut cement job;
- Anomalous flow or pressure profile during fracturing operations;
- Any non-routine incident listed in ECL §23-0305(8)(h) (i.e., casing and drill pipe failures, casing cement failures, fishing jobs, fires, seepages, blowouts); or
- Any violation of the ECL, its implementing rules and regulations, or any permit condition, including the requirement that the annulus between the surface casing and the next casing string be maintained in a non-pressurized condition.

DEC and the county health department will share information. All data on file with the county health department relative to the subject water well, including pre-existing conditions and any available information about the well's history of use and maintenance, shall be considered in determining the proper course of action with respect to well pad activities.

7.1.4.2 Sufficiency of As-Built Wellbore Construction

Wellbore construction is addressed by the existing GEIS. While the same concepts apply to wells used for high-volume hydraulic fracturing, some enhancements are proposed because of the high pressures that will be exerted, the large fluid volumes that will be pumped and potential concentration of the activity in areas without much subsurface well control.

Surface Casing

As defined in regulations, the purpose of surface casing is to protect potable fresh water.[48] For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 parts per million of sodium chloride or 1,000 parts per million of total dissolved solids.[49] As stated in Chapter 2, maximum depth of potable water in an area should be determined based on the best available data. This would include water wells and other oil and gas wells in the area, any available local or regional geological or hydrogeological reports, and information gleaned from the sources listed in Section 7.1.10.1. When information is not available, a depth of 850 feet to the base of potable water is a commonly used and practical generalization.

Current casing and cementing practices attached as conditions to all oil and gas permits require:

- surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into bedrock, whichever is deeper, and deeply enough to allow the blow-out preventer stack to contain any formation pressures that may be encountered before the next casing is run;

- surface casing shall not extend into zones known to contain measurable quantities of shallow gas, and, in the event such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and take Department-approved actions to protect the fresh water zone(s); and

- surface casing shall consist of new pipe with a mill test of at least 1,000 pounds per square inch, or used casing that is pressure tested before drilling ahead after cementing; welded pipe must also be pressure tested.

The following more stringent requirements are implemented as permit conditions in primary and principal aquifers:

[48] 6 NYCRR 550.3(au)

[49] 6 NYCRR 550.3(ai)

- surface casing hole must be drilled on air, fresh water or fresh water mud;

- surface casing must extend at least 100 feet below the deepest fresh water zone and at least 100 feet into bedrock;

- pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 pounds per square inch or reconditioned pipe that has been tested internally to a minimum of 2,700 psi; and

- if multiple fresh water zones are known to exist or are found or if shallow gas is present, multiple strings of surface casing may be required to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. Notification to the Department is required of the occurrence of fresh water or shallow gas zones not noted in the well permit application materials and prognosis, and the Department may require changes to the casing and cementing plan and may also require the immediate, temporary cessation of operations while such changes are developed, evaluated and approved.

All of the above requirements will remain in effect, enhanced as follows by the attachment of Supplementary Permit Conditions for High-Volume Hydraulic Fracturing:

1) The Supplementary Permit Conditions will require submission of a *Pre-Frac Checklist and Certification Form* (pre-frac form) at least 48 hours prior to commencement of high-volume hydraulic fracturing operations. Regarding the surface casing hole, the pre-frac form will:

    a. attest to well construction having been performed in accordance with the well permit or approved revisions,

    b. list the depth and estimated flow rates where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations, and

    c. include information about how any lost circulation zones were addressed.

Hydraulic fracturing will not be authorized to proceed without the above information and certifications.

Surface Casing Cement

Current casing and cementing practices attached as conditions to all oil and gas permits require:

- cementing by the pump and plug method and circulation to surface,

- minimum of 25% excess cement pumped, with appropriate lost circulation materials,

- testing of the mixing water for pH and temperature prior to mixing,
- cement slurry preparation to the manufacturer's or contractor's specifications to minimize free water in the cement, and
- no casing disturbance after cementing until the cement achieves a calculated compressive strength of 500 pounds per square inch.

The following more stringent requirements are implemented as permit conditions in primary and principal aquifers:

- minimum of 50% excess cement pumped, with appropriate lost circulation materials,
- squeezing or grouting from the surface, or through perforations, if circulation is not achieved and
- remedial action prior to drilling out of and below the surface casing if there is any evidence or indication of flow behind the surface casing.

All of the above requirements will remain in effect, enhanced as described above by the requirement in Supplementary Permit Conditions for a pre-frac form prior to high-volume hydraulic fracturing.

Intermediate and Production Casing Cement

Current casing and cementing practices set requirements for production casing cement and state that intermediate casing cement requirements will be reviewed and approved on an individual well basis. The requirements for production casing cement are as follows:

- Cement must extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less;
- If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows;
- Weighted fluid may be used in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem;

- Cementing shall be by the pump and plug method for all jobs deeper than 1,500 feet, with a minimum of 25% excess cement unless caliper rugs are run, in which case 10% excess will suffice;

- The mixing water shall be tested for pH and temperature prior to mixing; and

- Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 pounds per square inch is achieved before the casing is disturbed in any way.

The above requirements will remain in effect, enhanced as follows by the attachment of Supplementary Permit Conditions for High-Volume Hydraulic Fracturing:

1) The pre-frac form will be required as described above;

2) If intermediate casing is not installed, then production casing must be fully cemented to surface. If intermediate casing is installed, it must be fully cemented to surface, and production casing cement must be tied into the intermediate casing string with at least 300 feet of cement. Any request to waive the preceding requirement must be made in writing with supporting documentation and is subject to the Department's approval. The Department will only approve a waiver if open hole wireline logs and all other information collected during drilling from the same well pad verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented. In any event, the top of cement on the production casing must be at least 500 feet above the casing shoe or tied into the previous casing string with at least 300 feet of cement.

3) The operator must run a cement bond log to verify the cement bond on the intermediate casing, if any, and the production casing. Remedial cementing shall be required if the cement bond is not adequate to isolate hydraulic fracturing operations.

Centralizers

The use and purpose of centralizers, as recommended by GWPC, is to keep the casing centered in the wellbore so that cement adequately fills the space around it. Current casing and cementing practices attached as conditions to all oil and gas drilling permits require use of centralizers on all casing strings and specify adequate hole diameters and spacing for their use. Centralizers are required every 120 feet on surface casing, but no fewer than two may be run. These requirements will continue to apply to wells drilled for high-volume hydraulic fracturing.

Inspections to Witness Casing and Cementing Operations

Current casing and cementing practices attached as conditions to all oil and gas well drilling permits require notification to the Department prior to any surface casing pressure test. In primary and principal aquifer areas, the Department must be notified prior to surface casing cementing operations and cementing cannot commence until a state inspector is present. These requirements will continue to apply to wells drilled for high-volume hydraulic fracturing. Supplementary Permit Conditions for High-Volume Hydraulic Fracturing will require notification prior to surface casing cementing for all wells, so that Department staff has the opportunity to witness the operations.

7.1.4.3 Annular Pressure Buildup

Current casing and cementing practices require that the annular space between the surface casing and the next string be vented at all times to prevent pressure build-up in the annulus. If the annular gas is to be produced, a pressure relieve valve shall be installed in an appropriate manner and set at a pressure approved by the Department. Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing state that "under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test."

7.1.5 Hydraulic Fracturing Procedure

As detailed in Section 6.15, potential impacts to ground water from the high-volume hydraulic fracturing procedure itself are, in most cases, not reasonably anticipated. To the extent that any could occur, mitigation is provided by all of the enhanced requirements proposed as Supplementary Permit Conditions for High-Volume Hydraulic Fracturing and discussed above. These include:

- Requirement for private water well testing;
- Pit construction and liner specifications for well pad reserve pits;
- Requirement that tanks be used to contain flowback water on site;
- Appropriate secondary containment measures;
- Removal of fluids within specified time frames;
- Use of appropriate pressure-control procedures and equipment, including blow-out prevention equipment that is tested on-site prior to drilling ahead and fracturing equipment that is pressure tested with fresh water ahead of pumping fracturing fluid;

- Requirement for notification to DEC prior to cementing surface casing;
- Requirements for cement to surface and a cement bond log;
- Use of a the pre-frac form to certify wellbore integrity prior to fracturing; and
- Pre-fracturing pressure testing of casing from surface to top of treatment interval.

In addition, the Department will continue to require that the annulus between the surface casing and the next casing string not be shut-in, except during a pressure test, and more stringent surface casing and cementing practices, fluid removal practices and inspection requirements in primary and principal aquifer areas.

As explained in Section 6.1.5.2, the conclusion that harm to freshwater aquifers from fracturing fluid migration is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. In addition, as stated in Section 5.18.1.1, GWPC recommended a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. Therefore, the Department proposes that site-specific SEQRA review be required for the following projects:

1) any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along the entire proposed length of the wellbore is shallower than 2,000; and

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

Review would focus on local geological, topographical and hydrogeological conditions, along with proposed fracturing procedures to determine the potential for a significant adverse impact to fresh ground water. The need for a site-specific supplemental environmental impact statement will be determined based upon the outcome of the review.

7.1.6 Waste Transport

7.1.6.1 Drilling and Production Waste Tracking Form

Because of the anticipated high volume of flowback water compared to traditional operations, the paucity of reliable data regarding flowback water and production brine composition, NORM concerns, the number of wells that may be drilled and the current limited disposal options, the Department will require that a *Drilling and Production Waste Tracking Form* be completed and maintained by generators, haulers and receivers of all flowback water associated with activities addressed by this Supplement. The record-keeping requirements and level of detail will be similar to what is presently required for medical waste.[50] The form will be required regardless of whether waste is taken to a treatment facility, disposal well, centralized surface impoundment, another well pad, a landfill, or elsewhere.

7.1.6.2 Road Spreading

Flowback Water

As explained in Chapter 5 and presented in Appendix 12, consistent with past practice, the Department began in January 2009 notifying Part 364 haulers applying for, modifying, or renewing their Part 364 permit that flowback water may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to the Division of Mineral Resources.

Produced Brine

The notification described above puts Part 364 haulers on notice that any entity applying for a Part 364 permit or permit modification to use production fluid for road spreading must submit a petition for a beneficial use determination ("BUD") to the Department. For production fluids that will be used on roads, the BUD and Part 364 permit must be issued by the Department prior to the removal of any production brine from the well site. As set forth in the notification, the BUD petition must include analytical results from a NYSDOH laboratory of a representative sample for the following parameters: calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Dependent upon the analytical results, the Department may require additional analyses.

---

[50] http://www.dec.ny.gov/docs/materials_minerals_pdf/medwste.pdf

The foregoing list of analysis parameters is not unique or specific to production brine from the Marcellus or any other particular rock formation, but is meant to be inclusive of all potential produced brines. For Marcellus production brine, the Department will add a radioactivity scan as set forth in Section 7.1.81 of this Supplement, and the BUD petition will be denied if levels indicate a potential public exposure concern.

7.1.6.3 Flowback Water Piping

Flowback water piping and conveyances between well pads and centralized flowback water facilities (or any other destination) must be described in the fluid disposal plan required by 6 NYCRR 554.1(c)(1) and the MSG SWPPP. The fluid disposal plan must demonstrate that pipelines and conveyances will be constructed of suitable materials, maintained in a leak-free condition, regularly inspected and operated using all appropriate spill control and stormwater pollution prevention practices.

7.1.7 Centralized Flowback Water Surface Impoundments

The Department's regulations require submission and approval for a fluid disposal plan "[p]rior to the issuance of a well drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in sufficient quantities to be deleterious to the surrounding environment . . ."[51] Consequently, the EAF Addendum will require information on the disposition of flowback water. Any proposed centralized surface impoundment will be considered part of the project for the first well permit application that proposes its use. All well permit applications proposing use of a centralized flowback water surface impoundment will be considered incomplete until the Department has approved the surface impoundment. Consistent with GWPC's recommendation that long-term storage pits be prohibited within the boundaries of public water supplies (Section 5.18.1.2), the Department will not approve use of centralized flowback water surface impoundments within the boundaries of primary and principal aquifers or unfiltered water supplies (e.g., the NYC Watershed).

[51] 6 NYCRR 554.1(c)(1)

To address the potential environmental impacts identified in Section 6.1.7, standards from two of the Department's regulatory programs will be applied to review of proposed centralized flowback water surface impoundments.

First, if dam safety permitting criteria based on the height and storage capacity of the surface impoundment are met (see Figure 5.5), then construction must be in accordance with the Department's technical guidance document, *Guidelines for Design of Dams.*[52] Operation must be in accordance with the Department's document, *An Owner's Guidance Manual for the Inspection and Maintenance of Dams in New York State.*

Second, upon review of the existing regulatory framework for liquid containment, the Department has determined that the existing regulatory structure established for solid waste management facilities, 6 NYCRR Part 360 (Part 360), is most applicable for the containment, operational, monitoring and closure requirements for centralized flowback water management facilities.[53] While it is acknowledged that flowback waters are not solid wastes, the characteristics of the flowback waters best compare qualitatively with landfill leachate regulated under the Part 360 provisions. The liner requirements as they exist in Part 360 have been proven through time to be conservative and, more importantly, have been determined to provide the requisite level of protection to ensure preservation of the ground water quality resources at solid waste management facilities throughout the State. Therefore, the Department will apply the existing Part 360 standards as described below to its review of centralized flowback water surface impoundments pursuant to 6 NYCRR 554.1(c)(1).

As with all environmental containment systems, it is acknowledged that conservative liner requirements alone do not guarantee groundwater protection. Emphasis has to be placed on the importance of proper facility design, material selection, construction quality and facility operation and monitoring. All are equally important to best ensuring successful protection of the groundwater resources of New York State.

---

[52] *Guidelines for Design of Dams*is available on the Department's website at http://www.dec.ny.gov/docs/water_pdf/damguideli.pdf or upon request from the DEC Regoinal Permit Administrator.

[53] Part 360 regulations: http://www.dec.ny.gov/regs/2491.html

The specific provisions of Subpart 360-6 Liquid Storage will provide the overall requirements for either flowback surface impoundments or tanks, describing the minimum liner, operational, monitoring and closure requirements. These provisions will cross reference other applicable provisions of Part 360 which more specifically address liner system design, construction materials, construction quality assurance and construction certification requirements that likewise will be applicable to the flowback water containment systems discussed in the dSGEIS.

7.1.7.1 Purpose of a Double-Liner System

The best way to ensure that leakage is prevented in lined facilities is to minimize the hydraulic head on the liner system. In crafting the liquid containment requirements of Part 360, the Department determined that the best approach is to use a double liner system. In doing so, a certain amount of leakage is allowed through the upper liner system into a lower leak removal, detection and monitoring system which is designed to be free-flowing such that the rate of leakage withdrawal from the leak detection system prevents any appreciable hydraulic head from building up on the lower most liner system.

To help prevent damage from unstable ballast materials, a double liner system with a properly designed leak detection and monitoring system will not necessarily require large amounts of ballast material on the upper liner system as long as the leak detection and removal system functions such that no upward hydraulic pressures are imposed on the upper liner system. This mitigates concerns for damage from unstable ballast materials as described in Section 6.1.7.

7.1.7.2 Liner Materials

The provisions of subdivision 360-2.14(a) for non-hazardous industrial waste facilities allows the Department to exercise site-specific judgment and flexibility on liner, operational and closure requirements for certain industrial waste materials without the need for regulatory variance determinations. In establishing the specific requirements for the flowback water management based on the general flowback water characterization and the temporary nature of these facilities, Department staff may consider proposals to use alternate materials in constructing these facilities. For instance, design engineers have latitude in the geomembrane polymer selection based on the individual application, provided the following requirements are met:

- High Density Polyethylene Geomembranes must be a minimum thickness of 60 mils thick for adequate ability to field seam the material.

- Linear Low Density Polyethylene Geomembranes must be a minimum thickness of 40 mils for adequate ability to field seam the material.

- Polyvinyl Chloride (PVC) must be minimum thickness of 30 mils thick and must be double hot wedge seamed and all field seams tested using the air channel test.

- Certain reinforced geomembrane polymers also may be considered, in light of the durable nature of scrim-reinforced geomembranes which makes them more ideal for exposed applications.

Subpart 360-6 requires that the lowermost liner of a double lined surface impoundments be a composite liner which consists of a 2-foot thick low permeability compacted clay soil barrier overlain by and in direct contact with a geomembrane. The composite liner greatly reduces the effects of leakage from any geomembrane liner defects. However, the relative short-term nature of the surface impoundments compared to landfills and the anticipated quality of the flowback waters supports use of subdivision 360-2.14(a) to allow, at the design engineers discretion, the substitution of a geosynthetic clay liner (GCL) in lieu of the 2-foot thick compacted clay barrier in the composite. This latitude will ease construction and reduce construction related truck traffic if low permeability soil is not available in the area.

7.1.7.3 Application of Section 360-6.5 Double Liner Requirements

The lowermost liner for a centralized flowback water surface impoundment must be a single composite liner and may be designed with a GCL in lieu of the 2 foot thick compacted low permeability soil (1 X 10^{-7} cm/sec) specified in regulations. The GCL must be directly below a geomembrane, which in turn would be overlain by an appropriately designed and specified geocomposite drainage system. The drainage system must be designed to be free flowing and be capable of monitoring flows for liner performance. Above this leak detection layer would be another geomembrane liner that would be selected by the design engineer to address durability matters associated with exposure concerns if the upper geomembrane is left exposed.

The design engineer will be required to submit a construction quality control and construction quality assurance plan and perform final certification reporting upon completion of construction in accordance with the applicable provisions of Section 360-2.13.

The maximum leakage rate monitored between the two liner systems should not exceed 100 gallons per acre per day (based on a 30-day average). The facility owner shall notify the Department within 7 days of the determination of exceedance and submit a report within 14 days of the exceedance detailing a plan for corrective action and repairs of the liner system's performance. Final repair and certification of the repair must be submitted by a licensed professional engineer and approved by Department prior to putting the surface impoundment back into service.

Quality construction and installation needs to be assured. Construction problems will be immediately evident with the double liner system. Literature reveals that 97 percent of all geomembrane defects occur during facility construction. If a surface impoundment experiences high leakage rates at the beginning of operations, impoundment usage would need to be curtailed until repairs are made. This typically results in costly delays. Consideration should be given to use of electrical leak location services prior to putting the surface impoundment into service. Many landfill owners require this as part of the construction quality assurance testing to minimize delays in putting the landfill into service. This approach also makes sense for surface impoundments.

7.1.7.4 Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage

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

7.1.7.5 Closure Requirements

The closure requirements for liquid storage facilities under Subpart 360-6 are specified in section 360-6.6 Closure of Liquid Storage Facilities. These provisions detail the specific closure requirements for these containment structures and require any post-operation residues to be properly handled and disposed of as part of the process.

7.1.8 SPDES-Regulated Discharges

Flowback water and production brine are considered industrial wastewater. Wastewater is generated by many water users and industries. NYSDEC's EPA-approved program for the control of wastewater discharges is called the State Pollutant Discharge Elimination System and is commonly referred to as SPDES. The program controls point source discharges to ground waters and surface waters.

7.1.8.1 Treatment Facilities

SPDES permits are issued to wastewater dischargers, including treatment facilities such as Publically Owned Treatment Works (POTW's) operated by municipalities. SPDES permits include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations and/or mass loadings for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

POTWs

A POTW must have an approved pretreatment program, or mini-pretreatment program, developed in accordance with the above requirements in order to accept industrial wastewater from non-domestic sources covered by Pretreatment Standards which are indirectly discharged into or transported by truck or rail or otherwise introduced into POTWs.

The NYSDEC's Division of Water shares pretreatment program oversight (approval authority) responsibility with the USEPA. Indirect discharges to POTWs are regulated by 6NYCRR Part 750-2.9(b), National Pretreatment Standards, which incorporates by reference the requirements set forth under 40CFR Part 403, "General Pretreatment Regulations for Existing and New Sources of Pollution." In accordance with Division of Water TOGS 1.3.8, 6NYCRR Part 750-2.9, 40CFR Part 403, and 40 CFR 122.42, New York State POTW permittees with industrial pretreatment or mini-pretreatment programs are required to notify NYSDEC of new discharges or substantial changes in the volume or character of pollutants discharged to the permitted POTW. NYSDEC must then determine if the SPDES permit needs to be modified to account for the proposed discharge, change or increase.

Flowback water and production brine from wells permitted pursuant to this Supplement may only be accepted by POTWs with approved pretreatment or mini-pretreatment programs, as noted above, and an approved headworks analysis for this wastewater source as described below and as required by the POTW's State Pollutant Discharge Elimination System (SPDES) permit.

Appendix 21 is a list of POTW's with approved pretreatment and mini-pretreatment programs. In addition, any industrial wastewater source, including this source of wastewater, may only be discharged utilizing all treatment processes within the POTW. Admixture of untreated flowback water or other well development water to the treated effluent of the POTW is not allowed. Improper handling could result in noncompliance with terms of the permit or the Environmental Conservation Law and result in formal enforcement actions.

The large volumes of return water from high-volume hydraulic fracturing combined with the diverse mixture of chemicals and high total dissolved solids (TDS) that exist in both flowback water and produced brine, requires that the permittee submit a headworks analysis to the Department for review in accordance with DOW's Technical and Operational Guidance Series(TOGS)1.3.8. New Discharges to Publicly Owned Treatment Works. TOGS 1.3.8 was developed to assist NYSDEC permit writers in evaluating the potential effect of a new, substantially increased, or changed non-domestic discharge to a POTW on that facility's SPDES permit and pretreatment program. The DOW must determine whether the POTW has adequately evaluated the effects of the proposed discharge on POTW operation, sludge disposal, effluent quality, and POTW health and safety; whether the discharge will result in the discharge of a substance that will be subject to effluent limits, action levels, or other monitoring requirements in the facility's SPDES permit; and whether the proposed discharge contains any Bioaccumulative Chemicals of Concern or persistent toxic substances that may be subject to SPDES effluent limits or other Departmental permit requirements or controls. Appendix C of TOGS 1.3.8, *Guidance for Acceptance of New Discharges*, describes the analyses and submittals necessary for a POTW to accept a new source of wastewater. Note that if a facility has a currently approved headworks analysis in place for the parameters and concentrations of those parameters typically found in flowback water and produced brine, the permittee may assess the impacts of the proposed discharge against the existing headworks analysis.

Flowback water and produced brine must be fully characterized prior to acceptance by a POTW for treatment. Please note in particular Appendix C. IV of TOGS 1.3.8, "Maximum Allowable Headworks Loading (MAHW)." Flowback water or produced brine may contain inhibitory amounts of dissolved solids, as well as an elevated pH, residual hydraulic fracturing additives, heavy metals, and potentially barium or other radioactive substances. The POTW should perform a MAHW analysis to assure that the flowback water and produced brine will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include effluent limits for TDS, if not already identified in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge.

Specific information regarding these fluids, such as chemical makeup and aquatic toxicity, will be required for this analysis. DOW has developed the form in Appendix 22 (Hydrofracturing Chemical Form HFC) which may be used to simplify and expedite the evaluation process. The form must be submitted for each proposed chemical to identify active ingredients and toxicity of fracturing additives or formation constituents that may be present in the wastewater. If any confidentiality is allowed under State law based upon the existence of proprietary material, that fact may be noted in the submission. However, in no circumstance shall a fracturing additive be approved or evaluated in a headworks analysis without aquatic toxicity data. Department approval of the headworks analysis, and the modification of the POTW's SPDES permit if necessary, must be received prior to the acceptance of flowback water or produced brine from wells permitted pursuant to this Supplement.

In conducting the headworks analysis, the parameters that must be analyzed include, at a minimum:

- constituents that were present in the hydraulic fracturing additives
- pH, range, SU

- Oil and Grease
- Solids, Total Suspended
- Solids, Total Dissolved
- Chloride
- Sulfate
- Alkalinity, Total (CaCO3)
- BOD, 5 day
- Chemical Oxygen Demand (COD)
- Total Kjeldahl Nitrogen (TKN)
- Ammonia, as N
- Total Organic Carbon
- Phenols, Total
- and the following scans:
    - Priority Pollutants Metals
    - Priority Pollutants Volatiles
    - Priority Pollutants SVOC Base/Neutral
    - Priority Pollutants SVOC Acid
- Radioactive scan including:
    - Gross Alpha - EPA Method 900.0, Standard Methods 7110-B
    - Gross Beta - EPA Method 900.0, Standard Methods 7110-B
    - Radium - EPA Method 903.0, Standard Methods 7500-Ra B
    - Uranium - EPA Method 908, Standard Methods 7500-U
    - Thorium - EPA Method 910, Standard Methods 7500-Th

The high concentrations of Total Dissolved Solids (TDS) present in this source of wastewater may prove to be inhibitory to biological wastewater treatment processes. It has been noted that the concentrations of TDS in the return and process water increase over the life of the well. The expected concentrations of TDS for both the initial flowback water as well as for the ongoing well operation must therefore be considered in the development of the headworks analysis. It is incumbent upon the POTW to determine whether the volumes and concentrations of chemicals present in the flowback water or production brine would result in adverse impacts to the facility's treatment processes as part of the above headworks analysis.

Private Treatment Facilities

Privately owned facilities for the treatment and disposal of industrial wastewater from high-volume hydraulic fracturing operate in other states, including Pennsylvania. Similar facilities that might be constructed in New York would require a SPDES permit. Again, the SPDES permit for a dedicated treatment facility would include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

7.1.8.2 Disposal Wells

Because of the 1992 Finding that brine disposal wells require site-specific SEQRA review, mitigation measures are discussed here for informational purposes only and are not being proposed on a generic basis.

Flowback and disposal strata water quality must be fully characterized prior to permitting and injecting into a disposal well. Additional geotechnical information regarding the disposal strata's ability to accept and retain the injected fluid is also necessary. Form HFC, in Appendix 22, may be used to simplify and expedite the water quality evaluation process. The water quality parameters that must be analyzed are the same as those listed in Section 7.1.8.1 and additional information regarding the use of Form HFC is presented in that section.

The Department may propose monitoring requirements and/or discharge limits in the SPDES permit in addition to any requirements included in the required USEPA Underground Injection Control permit. These will be determined during the site-specific permitting process required by the Uniform Procedures Act and the 1992 Findings Statement. To be protective of the overlying potable water aquifers, the site-specific permitting process will consider the following topics:

- Distance to drinking water supplies or sources, surface waterbodies and wetlands.
- Topography, geology, and hydrogeology.
- The proposed well construction and operation program.
- Water quality analysis of the receiving stratum for TDS, chloride, sulfate and metals.
- Effluent limits for injectate constituents, and potential applicability of 6 NYCRR 703.6 groundwater effluent limits or the groundwater effluent guidance values listed in Division of Water TOGS 1.1.1.
- Potential requirement for upgradient and downgradient monitoring wells installed in the deepest identified GA or GSA potable water aquifer.

7.1.9 Solids Disposal

Cuttings may be managed within a closed loop system or discharged to the lined reserve pit. If cuttings are discharged to the reserve pit and a common reserve pit is used for multiple wells on the pad, cuttings may have to be removed several times to maintain the required two feet of freeboard set forth in Section 7.1.3.2. Care must be taken during this operation not to damage the liner.

Cuttings or a pit liner contaminated with oil-based mud must not be buried on site, but must be removed for disposal in a Part 360 solid waste facility. Supplementary permit conditions for high-volume hydraulic fracturing require consultation with the Department's Division of Solid and Hazardous Materials.

One operator has suggested annular disposal of drill cuttings. This is not an acceptable practice in New York and would not be approved.

Although not directly related to a water resources impact, consideration also should be given to monitoring and mitigating subsidence by adding fill as any uncontaminated drill cuttings that are buried on site dewater and consolidate.[54]

7.1.10 Protecting New York City's Subsurface Water Supply Infrastructure

The advent, in the late 1990s and early 2000s, of geothermal well drilling – also regulated under Article 23 of the ECL if the wells are deeper than 500 feet – led to mutually agreed upon protocols between the Department and the NYCDEP for processing permits to drill in New York City and Delaware, Dutchess, Greene, Orange, Putnam, Rockland, Schoharie, Sullivan, Ulster and Westchester Counties. The Department agreed to notify NYCDEP of any proposed well in the counties outside of New York City, so that NYCDEP could determine if the proposed surface location is within a 1,000-foot wide corridor surrounding a water tunnel or aqueduct. For any well that NYCDEP confirms is outside the corridor, the Department processes the permit application following its normal procedures without any further NYCDEP involvement to address subsurface infrastructure.

[54] Alpha, p. 2-15.

For any well within the 1,000-foot corridor, the Department notifies the applicant that the proposed drilling is an unlisted action and may pose a significant threat to a municipal water supply, necessitating a site-specific SEQRA finding. A negative declaration is only filed upon a demonstration to NYCDEP's satisfaction, through proposed drilling and deviation surveying protocols, that it is feasible to drill at the proposed location with confidence that there will be no impact to tunnels or aqueducts. NYCDEP is provided with a copy of each application for a permit to drill, and any permit issued requires notification to NYCDEP prior to drilling commencement.[55]

Prior to reaching the above-described agreement with NYCDEP, Department staff had considered applying the 660-foot protective buffer for underground mining operations that is provided by the oil and gas regulations to New York City's underground water tunnels and aqueducts.[56] However, those regulations require the underground mine operator (or, in this case, the tunnel operator) to provide detailed location information regarding its underground property rights to the Department. NYCDEP has not provided such maps for the subject counties, and the 1,000-foot protective corridor suggested by NYCDEP was agreeable to Department staff because it is more protective and is consistent with the GEIS criteria for requiring supplemental environmental review for proposed well locations within 1,000 feet of municipal water supply wells.

To prevent impacts to NYC's subsurface water supply infrastructure, Department staff will continue to follow the above protocol for any proposed Article 23 well, including any proposed gas well, in the NYC Watershed. Except for the horizontal drilling and hydraulic fracturing that may occur thousands of feet below the depth of any tunnel or aqueduct, the methods and technologies for geothermal wells are the same as for natural gas wells.

7.1.11 Protecting the Quality of New York City's Drinking Water Supply

New York City's drinking water sources and water supplies are subject to the NYCDEP's Watershed Rules and Regulations and the Delaware River Basin Commission's regulations,

---

[55] Letter dated April 18, 2007, from Kathleen F. Sanford (Chief, Permits Section, Bureau of Oil & Gas Regulation, NYSDEC Division of Mineral Resources) to Kenneth E. Moriarty, Director, In-House Design, Bureau of Engineering Design & Construction, NYCDEP).

[56] 6 NYCRR 552.4

procedures and programs, in addition to the applicable regulations, policies, and guidelines of the NYSDEC (various divisions), NYSDOH, and USEPA. Local governments and agencies also may exert some control concerning specific activities within their respective jurisdiction, such as road use. The regulations, standards, policies, programs, and procedures of these various federal, state, and local authorities cover a myriad of physical, chemical, and biological aspects that directly and indirectly protect the quantity and quality of the City's drinking water.[57] The web of interrelated regulatory requirements is likely to present significant practical challenges to an operator wishing to engage in high volume hydraulic fracturing within the bounds of the New York City Watershed.

Activities within the NYC watershed that are deemed to potentially affect the City's water supplies require extensive documentation, reviews, and permits, as applicable to the proposed activity. Drilling and high-volume hydraulic fracturing for horizontal shale gas wells is an activity that will be subject to all of the mitigation measures discussed in the GEIS and the Supplement, in addition to requiring approval and compliance with multiple authorities.

Review of the existing authorities relative to both water resources in general and the New York City Watershed in particular indicates that the City's water supply is adequately protected regarding water quality and quantity, and that the possibility of high-volume hydraulic fracturing presents no realistic threat to the Filtration Avoidance Determination. New York City's control of a substantial amount of acreage surrounding the reservoirs through fee ownership or conservation easements provides further protection. Drilling and high-volume hydraulic fracturing cannot occur on such acreage without the City's permission.[58] Similarly, New York State's ownership of land within the New York City watershed, including portions of the Catskill Forest Preserve, provides protection.

Setbacks and procedures proposed in this Supplement, along with supplementary permit conditions for high-volume hydraulic fracturing will provide protection to surface water and ground water statewide. Proposed enhanced procedures and requirements specifically applicable to the New York City Watershed include:

---

[57] Alpha, p. 4-30

[58] Alpha, p. 4-30

- Prohibition against centralized flowback water surface impoundments within the boundaries of the New York City Watershed (Section 7.1.7),

- Requirement in an unfiltered watershed to remove fluids from any reserve pit or on-site (i.e., well pad) tanks within seven days of completing drilling and stimulation operations at the last well on the pad, or immediately if operations are suspended and the site will be left unattended (Section 7.1.3.2) , and

- Site-specific SEQRA determination for any proposed well pad within 300 feet of a reservoir, reservoir stem or controlled lake[59] or within 150 feet of a watercourse (Section 7.1.12.2).[60]

To the extent practical, operators should place any blending unit with a mixing hopper used for fracturing operations at least 500 feet from reservoir, reservoir stem or controlled lake and 100 feet from a watercourse or state-regulated wetland in the New York City Watershed, in consideration of Section 18-32(b) of NYC's Watershed Rules and Regulations relative to process tanks.

7.1.12 Setbacks

The New York State Department of Health (NYSDOH) recognizes separation distances, or setbacks, as a crucial element of protecting water resources against contamination.[61] While the cited reference pertains specifically to drinking water wells, setbacks also mitigate potential impacts to other water resources. As established in the 1992 GEIS with respect to municipal water supply wells, setback distances can be used to define the level of environmental review and mitigation required for a specific proposed activity.

The proposed setback distances advanced herein reflect consideration of the following information reviewed by Department staff:

- The 1992 GEIS and its Findings.

---

[59] The terms "reservoir stem" and "controlled lake" are applicable only in the New York City Watershed, as defined by the Watershed Rules and Regulations; see SGEIS Section 2.4.4.3.

[60] The term "watercourse" is applicable only in the New York City Watershed, as defined by the Watershed Rules and Regulations; see SGEIS Section 2.4.4.3.

[61] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs1_additional_measures.htm, viewed 8/26/09

- NYSDOH's required water well separation distances, set forth in Appendix 5-B of the State Sanitary Code.[62] Although sites specifically related to natural gas development and production are not explicitly listed among the potential contaminant sources addressed by Appendix 5-B, DOH staff assisted Department staff in identifying listed sources which are analogous to activities related to high-volume hydraulic fracturing.

- Results and discussion provided by Alpha Environmental Consultants, Inc. (Alpha), to NYSERDA regarding Alpha's survey of regulations related to natural gas development activities in Pennsylvania, Colorado, New Mexico, Wyoming , Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas.[63]

- Results and discussion provided by Alpha to NYSERDA regarding Alpha's review of the rules and regulations pertaining to protection of water supplies in New York City's Watershed.[64] Again, although natural gas development activities are not specifically addressed, Alpha identified activities which could be considered analogous to aspects of high-volume hydraulic fracturing, including:

    - Hazardous materials storage,
    - Radioactive materials disposal,
    - Storage of petroleum products,
    - Impervious surfaces,
    - Stormwater prevention plans,
    - Miscellaneous point sources, and
    - Solid waste disposal.

- Local watershed rules and regulations for various jurisdictions within the Marcellus and Utica Shale fairways. The counties searched included Broome, Chemung, Chenango, Cortland, Delaware, Madison, Otsego, Steuben, Sullivan, Tioga and Tompkins. Local watershed rules and regulations include setbacks from water supplies related to the following activities which are potentially analogous to aspects of high-volume hydraulic fracturing:

    - Chlorides/salt storage,
    - Burial of storage containers containing toxic chemicals or substances,

---

[62] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09

[63] Alpha, 2009.

[64] Alpha, 2009.

- Disposal of radioactive materials by burial in soil, and
- Direct discharge of polluted liquid to the ground or a waterbody.

7.1.12.1 Setbacks from Ground Water Resources

The following discussion pertains to the lateral distance, measured at the surface, to a water supply well or spring from one of the following:

- the surface location of the proposed well,
- the closest edge of the well pad, or
- a centralized surface flowback impoundment.

The proposed well and well pad setbacks apply to well permit applications where the target fracturing zone is either at least 2,000 feet deep or 1,000 feet below the underground water supply. These wells would be drilled vertically through the aquifer, so that the aquifer penetration at each well is beneath the well's surface location. Well permit applications where the target fracturing zone is less than either 2,000 feet deep or 1,000 feet below a known underground water supply are addressed in Section 7.1.5.

The EAF addendum for high-volume hydraulic fracturing will require evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within half a mile (2,640 feet) of any proposed drilling location. The Department proposes that this distance is adequate to ensure the 2,000-foot SEQRA threshold for public water supply wells is properly applied. The operator will be required to identify the wells and springs, and provide available information about their depth, completed interval and use. Use information will include whether the well is public or private, community or non-community and of what type in terms of the facility or establishment it serves if it is not a residential well. Information sources available to the operator include:

- direct contact with municipal officials,
- direct communication with property owners and tenants,
- communication with adjacent lessees,

- EPA's Safe Drinking Water Act Information System database, available at http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY , and

- DEC's Water Well Information search wizard, available at http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty .

Upon receipt of a well permit application, Department staff will compare the operator's well list to internally available information and notify the operator of any discrepancies or additional wells that are indicated within half a mile of the proposed well pad. The operator will be required to amend its EAF Addendum accordingly.

Public Water Supply Wells

The Department's 1992 SEQRA review found that issuance of a permit to drill less than 1,000 feet from a municipal water supply well is considered "always significant" and requires a site-specific Supplemental Environmental Impact Statement (SEIS) dealing with groundwater hydrology, potential impacts and mitigation measures. Any proposed well location between 1,000 and 2,000 feet from a municipal water supply well requires a site-specific assessment and SEQRA determination, and may require a site-specific SEIS. The GEIS provides the discretion to apply the same process to other public water supply wells. The Department is not proposing to alter its 1992 Finding with respect to municipal supply wells, and will continue to exercise its discretion regarding applicability to other public supply wells (i.e., community and non-community water supply system wells) when information is available.

For multi-well pads and high-volume hydraulic fracturing, the site-specific SEQRA process should also consider the adequacy of proposed measures to prevent surface spills and leaks on the well pad that could impact the groundwater supply. However, review of NYSDOH's separation distances in Appendix 5-B of the State Sanitary Code indicates that a 300-foot setback is the largest setback required for any potential contaminant. [65] This is the setback which applies to "chemical storage site(s) not protected from the elements," which could be considered analogous to uncovered pits or surface impoundments which hold flowback water. A 150-foot separation distance is required for "fertilizer and/or pesticide mixing and/or clean up areas," which are comparable to the areas on the well pad used for handling and mixing of frac

[65] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09

additives. Review of local Watershed Rules and Regulations, including New York City's, did not reveal any required setbacks for analogous activities that exceed the 2,000-foot threshold for site-specific review established in 1992 for municipal supply wells. Neither did Alpha's regulatory survey. Because the 2,000-foot threshold so greatly exceeds the NYSDOH-required setback distances for analogous activities that could occur on the pad, measuring the distance to the public supply well from the proposed surface location of the well itself (instead of from the edge of the well pad) is sufficiently protective with respect to potential spills or leaks on the well pad.

Centralized flowback water surface impoundments will be designed specifically to prevent groundwater infiltration, will be equipped with leak detection and groundwater monitoring systems, and do not involve the potential for undetected wellbore-to-wellbore contamination. Therefore, any setback from a public water supply well is based primarily on a concern about surface spills. In light of the above discussion about NYSDOH's separation distances for the analogous activity of "chemical storage site(s) not protected from the elements," the Department proposes that site-specific SEQRA review be required for the following project:

1) any proposed centralized flowback water surface impoundment within 300 feet of a public water supply well.

Areas where the Department proposes to disallow centralized flowback surface impoundment are listed in Section 7.7. The above proposed setback would apply outside those areas.

Private Water Wells and Domestic Supply Springs

Chapter 6 describes potential impacts related to high-volume hydraulic fracturing that may require enhanced protections for private water wells and domestic-supply springs. These concerns stem more from handling greater fluid volumes on the surface than from downhole activities. Fluid and chemicals could be present and handled anywhere on the well pad. Setbacks, therefore, should be measured from the edge of the well pad.

As stated above, pits or open surface impoundments that could contain flowback water are analogous to "chemical storage site(s) not protected from the elements," which are subject to a

300-foot separation distance from water wells under Appendix 5-B of the State Sanitary Code.[66] Flowback water tanks and additive containers could be compared to "chemical storage site(s) protected from the elements," which require a 100 foot setback from water wells.[67] Handling and mixing of frac additives onsite is comparable to "fertilizer and/or pesticide mixing and/or clean up areas," which require a 150 foot distance from water wells.[68]

Based on these existing DOH-established separation distances, the Department proposes that site-specific SEQRA review be required for the following high-volume hydraulic fracturing projects:

1) any proposed well pad within 150 feet of a private water well or domestic-supply spring, and

2) any proposed centralized surface flowback impoundment within 300 feet of a private water well or domestic-use spring.

Areas where the Department proposes to disallow centralized flowback impoundment are listed in Section 7.7. The above proposed setback would apply outside those areas.

7.1.12.2 Setbacks from Surface Water Resources

Application of setbacks from surface water resources prevents direct flow of the full, undiluted volume of a spilled contaminant into a surface water body. Some amount of soil adsorption or evaporation would occur in the event of a spill. Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any "public stream, river or other body of water."[69] The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the entire well site instead of just the well itself.

Significant surface spills at well pads which could contaminate surface water bodies, including municipal supplies, are most likely to occur during activities which are closely observed and controlled by personnel at the site. More people are present to monitor operations at the site

---

[66] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09

[67] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09

[68] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09

[69] 6 NYCRR Part 553.2

during high-volume hydraulic fracturing and flowback operations than at any other time period in the life of the well pad. Therefore, any surface spills during these operations are likely to be quickly detected and addressed rather than continue undetected for a lengthy time period. Other factors which mitigate the risk of surface water contamination resulting from well pad operations include the following:

- Required multi-sector industrial stormwater permit coverage, including a Stormwater Pollution Prevention Plan (SWPPP).
- Supplementary Permit Conditions for High-Volume Hydraulic Fracturing (see Appendix 10) , which are proposed to include:
  - Pit construction and liner specifications for well pad reserve pits;
  - Requirement that tanks be used to contain flowback water on site;
  - Appropriate secondary containment measures;
  - Use of appropriate pressure-control procedures and equipment, including blow-out prevention equipment that is tested on-site prior to drilling ahead and fracturing equipment that is pressure tested with fresh water ahead of pumping fracturing fluid; and
  - Pre-fracturing pressure testing of casing from surface to top of treatment interval.
- SGEIS setbacks related to potential surface activities measured from the edge of the well pad instead of from the well. Municipal ownership of land surrounding municipal surface water supplies may provide additional protection if the municipal-owned buffer exceeds the setback distance. Other waterfront owners may decline to lease or offer only non-surface entry leases [e.g., Otsego Lake owners around the lake include NYS (Glimmerglass State Park), Clark Foundation, etc.]
- Proposed requirement for closed-loop drilling in floodplains.
- The Department's existing requirement for a Freshwater Wetlands Permit in wetland or 100-foot buffer zone.

With respect to surface municipal supplies, the GEIS found that a 150-foot distance between the wellsite and a surface water supply would provide adequate protection in the event of an accidental spill. Required erosion and sedimentation control plans would address potential impacts to nearby waterbodies from ground disturbance. (As discussed elsewhere in this document, the Department has since determined that stormwater permit coverage is required for disturbance greater than one acre.)

Reservoir setbacks for comparable activities in the NYC Watershed Rules and Regulations range between 300 and 500 feet.[70] Other local Watershed Rules and Regulations establish various setbacks between 20 and 1,000 feet, but they generally pertain either to actual burial of materials for disposal purposes or direct discharges to the ground or surface waterbodies. Burial or direct discharges to the ground of fracturing fluid, additive chemicals or flowback water are not proposed and would not be approved. The only on-site burial discussed in Chapter 5 of this document pertains to uncontaminated cuttings and pit-liners associated with air or fresh-water drilling, as allowed under the 1992 GEIS. Direct discharges to surface water bodies are regulated by the Department's SPDES permitting program.

The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.[71] Colorado's new Public Water System Protection rule requires a variance for surface activity, including drilling, completion, production and storage, within 300 feet of a surface public water supply.[72]

Many local Watershed Rules and Regulations, including New York City's, require smaller setbacks from watercourses, as specifically defined within the watershed (see Section 2.4.4.3) than from reservoirs.

Based on the above information and mitigating factors, the Department proposes that site-specific SEQRA review be required for the following projects:

- any proposed well pad within 300 feet of a reservoir, reservoir stem or controlled lake; [73]
- any proposed well pad within 150 feet of a watercourse,[74] perennial or intermittent stream, storm drain, lake or pond;

---

[70] Alpha, 2009.

[71] Alpha, 2009.

[72] http://cogcc.state.co.us/RR_Docs_new/rules/300series.pdf, viewed 8/26/09

[73] The terms "reservoir stem" and "controlled lake" are applicable only in the New York City Watershed, as defined by the Watershed Rules and Regulations; see SGEIS Section 2.4.4.3.

- any proposed centralized flowback water impoundment within 1,000 feet of a reservoir; and

- any proposed centralized flowback water surface impoundment within 500 feet of a perennial or intermittent stream, wetland, storm drain, lake or pond.

Greater setback distances are proposed for centralized flowback water surface impoundments than for well pads for the reasons described in Section 7.7. Areas where the Department proposes to disallow centralized flowback surface impoundments are also listed in Section 7.7. The above proposed setbacks would apply outside those areas.

7.2 Protecting Floodplains

As detailed in Section 2.4.9, nearly all communities in New York with identified flood hazard areas participate in the National Flood Insurance Program (NFIP). The NFIP requires that a floodplain development permit issued by the local government be obtained before commencing any floodplain development activity.

The EAF Addendum will require the applicant to confirm that Flood Insurance Rate Maps and, if applicable, Flood Boundary and Floodway maps are checked to identify whether a proposed well pad is in a 100-year floodplain and a floodway.

Supplementary permit conditions for high-volume hydraulic fracturing will require that if a local floodplain development permit is necessary, a copy must be provided to the Department prior to any site disturbance. Because of the length of time that activity may continue at a multi-well pad, a closed-loop tank system will be required instead of a reserve pit for managing fluids and cuttings. Additional comprehensive guidelines relative to site construction in flood-prone areas are presented in Chapter 8 of the GEIS.

With respect to fluid disposal plans required under 6 NYCRR 554.1(c)(1), centralized flowback water surface impoundments will not be approved in 100-year floodplains, nor will above-ground flowback water piping and conveyances.

[74] The term “watercourse” is applicable only in the New York City Watershed, as defined by the Watershed Rules and Regulations; see SGEIS Section 2.4.4.3.

7.3 Protecting Freshwater Wetlands

Section 2.4.10 summarizes the State's Freshwater Wetlands regulatory program, which addresses activities within 100 feet of regulated wetlands. In addition, the federal government regulates development activities in wetlands under Section 404 of the Clean Water Act.

The Department found in 1992 that issuance of a well permit when another Department permit is necessary requires a site-specific SEQRA determination relative to the activities or resources addressed by the other permit. In such instances, which include Freshwater Wetlands Permits, the well permit is not issued until the SEQRA process is complete and the other permit is issued.

Mitigation measures for avoiding wetland impacts from well development activities are described in Chapter 8 of the GEIS, which provides that well permits are issued for locations in wetlands only when alternate locations are not available. Potential mitigation measures are not limited to those discussed in the GEIS, but may include other alternatives recommended by Fish, Wildlife and Marine Resources staff based on current techniques and practices. Additional measures proposed in this Supplement include the following:

- Requirement that, to the extent practical, fuel tanks for drilling rigs not be placed within 500 feet of a wetland (Section 7.1.3.1) ;
- Requirement for secondary containment consistent with the Department's SPOTS 10 for any drilling rig's fuel tank, regardless of size, that is placed within 500 feet of a wetland (Section 7.1.3.1); and
- Requirement for a site-specific SEQRA determination for any fluid disposal plan submitted pursuant to 6 NYCRR 554.1(c)(1) that includes a centralized flowback water surface impoundment within 500 feet of a regulated wetland (Section 7.1.12.2).

7.4 Protecting Ecosystems and Wildlife

Water withdrawal, invasive species concerns, and use of centralized flowback water surface impoundments are indentified in Chapter 6 as the ecosystem and wildlife concerns specifically related to high-volume hydraulic fracturing that are not addressed by the GEIS. Mitigation of the potential adverse impacts of water withdrawal is discussed in Section 7.1.1. The following text addresses invasive species and use of centralized flowback water surface impoundments.

7.4.1 *Invasive Species*

Chapter 26 of the Laws of New York, 2008, amended the Environmental Conservation Law (ECL) to create the New York Invasive Species Council[75,76] and define the DEC's authority regarding control of invasive species in New York. The Council, co-lead by the DEC and the Department of Agriculture and Markets (DAM), comprises the Department of Transportation (DOT), the Office of Parks, Recreation and Historic Preservation (OPRHP), the State Education Department (SED), the Department of State (DOS), the Thruway Authority, the New York State Canal Corporation, and the Adirondack Park Agency (APA).

The role of the Council includes identifying actions to prevent the introduction of invasive species, detect and respond rapidly to control populations of invasive species, monitor invasive species populations, provide for the restoration of native species and habitats that have been invaded, and promote public education on invasive species. [77]

Additionally, a comprehensive management plan is being developed which will address all taxa of invasive species in New York, with an emphasis on prevention, early detection and rapid response, and opportunities for control and restoration to prevent future damage. In accordance with ECL §9-1705(5)(c), the plan will incorporate the approved New York State Aquatic Nuisance Species Management Plan, the Lake Champlain Basin Aquatic Nuisance Species Management Plan, and the Adirondack Park Aquatic Nuisance Species Management Plan.

The Council will also submit to the legislature and governor a report recommending a four-tier system for non-native animal and plant species. The system will contain proposed lists of prohibited, regulated and unregulated species, and a procedure for the review of any non-native species that is not on the aforementioned lists before the use, distribution or release of such non-native species.

---

[75]ECL § 9-1707

[76] The New York Invasive Species Council supplanted the Invasive Species Task Force that was established in 2003 to explore the invasive species issue and provide recommendations to the Governor and Legislature by November 2005. The task force's findings and recommendations are summarized in the "Final Report of the New York State Invasive Species Task Force," which is available at http://www.dec.ny.gov/docs/wildlife_pdf/istfreport1105.pdf.

[77] ECL §9-1705(5)(b)

While the Council is currently developing a comprehensive invasive species management plan and the four-tier system previously discussed, ECL §9-1709(2)(d) authorizes the Department to prohibit and actively eliminate invasive species at project sites regulated by the State. This responsibility falls within the purview of the Department's Division of Fish, Wildlife and Marine Resources.

7.4.1.1 Terrestrial

In order to mitigate the potential transfer of terrestrial invasive species from project locations associated with high-volume hydraulic fracturing, including well pads, access roads, and engineered impoundments for fresh water and flowback water storage, well operators will be required to conduct all activities in accordance with the best management practices below. This requirement will be reflected by a permit condition which will be included on all well permits where high-volume hydraulic fracturing is proposed.

Survey for the Presence of Invasive Species

Invasive species control is two-fold in that it involves both limiting the spread of existing invasive species and limiting the introduction of new invasive species. In order to accomplish these objectives, it is necessary to identify the types of invasive species which are present at a project site as well as map the locations and extent of any established population.

Therefore, the Department will require that well operators submit, with the EAF Addendum, a comprehensive survey of the entire project site, documenting the presence and identity of any invasive plant species. This survey will establish a baseline measure of percent aerial coverage and, at a minimum, must include the plant species identified on the Interim List of Invasive Plant Species in New York State[78]. A map (1:24,000) showing all occurrences of invasive species within the project site must be produced and included with the survey as part of the EAF Addendum.

Field notes, photographs and GPS handheld equipment should be utilized in documenting any occurrences of invasive species and all such occurrences must be clearly identified in the field with signs, flagging, and/or stakes prior to any ground disturbance. Supplementary permit

[78] This list appears in Tables 6.4 and 6.5.

conditions for high-volume hydraulic fracturing will specify that if the invasive species survey submitted with the EAF Addendum shows the presence of invasive species in the topsoil, consultation with the Department's Division of Fish, Wildlife and Marine Resources is required prior to any ground disturbance.

Preventing the Spread of Invasive Species

- Prior to any ground disturbance, any invasive plant species encountered at the site should be stripped and removed. Cut plant materials should be placed in heavy duty, 3 mil or thicker, black, contractor quality plastic cleanup bags. The bags should then be securely tied and transported from the site to a proper disposal facility in a truck with a topper or cap, in order to prevent the spread or loss of the plant material during transport.

- Cut invasive plant species materials should not be disposed of into native cover areas.

- Machinery and equipment, including hand tools, used in invasive species affected areas must be pressure-washed and cleaned with water (no soaps or chemicals) prior to leaving the invasive species affected area to prevent the spread of seeds, roots or other viable plant parts. This includes all machinery, equipment and tools used in the stripping, removal, and disposal of invasive plant species.

- Equipment or machinery shall not be washed in any waterbody or wetland, and run-off resulting from washing operations should not be allowed to directly enter any waterbodies or wetlands.

- Loose plant and soil material that has been removed from clothing, boots and equipment, or generated from cleaning operations shall either be a) rendered incapable of any growth or reproduction or b) appropriately disposed of off-site. If disposed of off-site, the plant and soil material shall be transported in a secure manner.

Preventing New Invasive Species Introductions

- All machinery and equipment to be used in the construction of the proposed project, including but not limited to trucks, tractors, excavators, and any hand tools, must be washed with high pressure hoses and hot water prior to delivery to the project site to insure that they are free of invasive species.

- All fill and/or construction material (e.g. gravel, crushed stone, top soil, etc.) from offsite locations should be inspected for invasive species and should only be utilized if no invasive species are found growing in or adjacent to the fill/material source.

- Only certified weed-free straw should be utilized for erosion control.

Restoration and Preservation of Native Vegetation

- Native vegetation should be reestablished and weed-free mulch should be used on bare surfaces to minimize weed germination.

- Only native (non-invasive) seeds or plant material should be used for re-vegetation during site reclamation. An appropriate native seed mixture should be selected based on pre-disturbance surveys.

- All seed should be from local sources to the extent possible and should be applied at the recommended rates to ensure adequate vegetative cover to prevent the colonization of invasive species.

- As part of site reclamation, re-vegetation should occur as quickly as possible at each project site.

- Any top soil brought to the site for reclamation activities must be obtained from a source known to be free of invasive species.

- The site should be monitored for new occurrences of invasive plant species following partial reclamation. If new occurrences are observed, they should be treated with appropriate physical or chemical controls.

General

- Implementation of the above practices must be in accordance with a site-specific and species-specific invasive species mitigation plan that includes seasonally appropriate specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.). The invasive species mitigation plan must be available to the Department upon request and available on-site for a Department inspector's review at any time that related activities are occurring.

- The well operator should assign an environmental monitor to check that all trucks, machinery and equipment have been washed prior to entry and exit of the project site and that there is no dirt or plant material clinging to the wheels, tracks, or undercarriage of the vehicles or equipment.

- Any new invasive species occurrences found at the project location should be removed and disposed of appropriately.

7.4.1.2 Aquatic[79]

It is beneficial to the operators to implement water conservation and recycling practices because of the potential difficulties obtaining the large volumes of water needed for hydraulic fracturing. Most or all operators will recycle or reuse flowback water to reduce the need for fresh water.

It is possible that some unused fresh water may remain in a surface impoundment after drilling and hydraulic fracturing is completed. This is likely in circumstances where operators build large centralized surface impoundments to hold water for all drilling and hydraulic fracturing operations within a several mile radius. Unused water may be transported by truck or pipeline and discharged into tanks or surface impoundments for use at another drilling location. It also is possible that unused water could be transported and discharged at its point of origin with proper approval. Either of these options avoids the transfer of invasive species into a new habitat or watershed. Precautions must be implemented, especially when water is stored in surface impoundments, to preclude the transfer of invasive species into new habitats or watersheds.

Unused fresh water also could be transported to a wastewater treatment facility for processing, although this is considered unlikely given the anticipated demand for water in the drilling and hydraulic fracturing process. As detailed in Section 7.1.8.1, flowback water cannot be taken to a publicly owned treatment works without the Department's approval. Standard treatment processes at waste water treatment plants, such as dissolved air flotation, have been shown to successfully remove biological particles and sediments that might harbor invasive species; however, the safest method to avoid transfer of invasive species is to not transfer water from one waterbody to another.

Regulatory protections exist to mitigate the potential transfer of invasive species. Regulations and policies of SRBC and DRBC both address the transfer, reuse and discharge of water and have specific provisions to prevent transfer of invasive species. Table 7.3 is a matrix of SRBC and DRBC regulations pertaining to transfer of invasive species. The regulations are identified that specifically address the transport of invasive or nuisance aquatic species. Other regulations in Table 7.3 do not specifically relate to invasive species, but the required actions and policies nonetheless may have the effect of reducing or eliminating their transport.

[79] Text provided by Alpha, p. 3-6 *et seq.*, and supplemented by DEC

The SRBC's policy is to discourage the diversion or transfer of water from the basin with the objective of conserving and protecting water resources. Additionally, the SRBC specifically requires that "any unused (surplus) water shall not be discharged back to the waters of the basin without appropriate controls and treatment to prevent the spread of aquatic nuisance species."

The DRBC controls both exportation and importation of water from the Delaware River Basin. The DRBC's Rules of Practice and Procedure state that a project sponsor (e.g., operator) may not discharge to surface waters of the basin or otherwise undertake the project (gas well) until the sponsor has applied for, and received, approval from the commission. Flow-back water cannot be taken to a publicly owned treatment works within the Delaware River Basin without the approval of the DRBC. DRBC also prohibits discharge to the waters of the basin without prior approval. These actions and policies effectively control the use, withdrawal, discharge, and transfer to water from and into the basin and reduce the potential for transfer of invasive aquatic species.

The measures and protocols adopted by the SRBC and DRBC appear to be sufficient to address the potential for transfer of invasive species associated with water use for high-volume hydraulic fracturing. To the extent that operators seek to obtain, transport, use, and discharge water outside the jurisdictional boundaries of SRBC and DRBC, the NYSDEC may consider requiring equivalent mitigation measures for both large-scale basins and at smaller scales to avoid invasive species transfer.

7.4.2 Centralized Flowback Water Surface Impoundments

Impoundments should be constructed to be unattractive to wildlife. The inside slopes that could come into contact with fluctuating flowback water levels should be kept clear of vegetation. The impoundment must be fenced and to prevent access by larger species of wildlife. In addition, installation of netting should be considered as an additional measure to prevent wildlife from using the impoundment.

TABLE 7.3
Summary of Regulations Pertaining to Transfer of Invasive Species

Agency	Document		Article	Regulation Summary
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,8	All flowback and produced fluids, including brines, must be treated and disposed of in accordance with applicable state and federal law.
SRBC	Regulation of Projects		18 CFR Part 806.24,b,3,c	For diversions into the SRB, must provide: (1) the source, amount, and location of the diverted water,and (2) the water quality classification, if any, of the SRBC discharge stream and the discharge location(s). (3) All applicable withdrawal or discharge permits or approvals must have been applied for or received, and must prove that the diversion will not result in water quality degradation that may be injurious to any existing or potential ground or surface water use.
SRBC	Regulation of Projects		18 CFR Part 801.3,b	The SRBC will require evidence that proposed interbasin transfers of water will not jeopardize, impair or limit the efficient development and management of the SRBC's water resources, or any aspects of these resources for in-basin use, or have a significant unfavorable impact on the resources of the basin and the receiving waters of the Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 801.3,c,1	Allocations, diversions, or withdrawals of water must be based on (1) the rights of landholders in any watershed to use the stream water in reasonable amounts and to have the stream flow not unreasonably diminished in quality or quantity by upstream use or diversion of water; and (2) on the maintenance of the historic seasonal variations of the flows into Chesapeake Bay.
SRBC	Regulation of Projects		18 CFR Part 806.23,2	The SRBC may deny or limit an approval if a withdrawal may cause significant adverse impacts to SRB water, including: lowering of groundwater or stream flow levels; rendering competing supplies unreliable; affecting other water uses; causing water quality degradation that may be injurious to any existing or potential water use; affecting any living resources or their habitat; causing permanent loss of aquifer storage capacity; or affecting low flow of perennial or intermittent streams.
SRBC	Federal Register, Vol 73, No. 247, Rules and Regulations		18 CFR Part 806.22,f,6	Flowback fluids or produced brines used for hydrofracturing must be separately accounted for, but will not be included in the daily use volume or be subject to the mitigation requirements of § 806.22 [b].
SRBC	Standard Docket Conditions Contained In Gas Well **Consumptive Water Use**	*	Item 10.	Unused water shall not be discharged back to the SRB waters without appropriate controls and treatment to prevent the spread of aquatic nuisance species.
SRBC	Regulation of Projects		18 CFR Part 806.25,b, 4	Industrial water users must evaluate and utilize applicable recirculation and reuse practices.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 4. (Not contained in all approvals)	Within ninety (90) days of this approval, the project sponsor shall submit a plan of study and a schedule for completion to conduct a survey and evaluate the potential impacts on the rare and protected freshwater mussels located in the Susquehanna River within the area of the withdrawal.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets		Item 5. (Not contained in all approvals)	This approval does not become effective until the SRBC is satisfied that the withdrawal has no adverse impacts to the rare and protected freshwater mussel species of concern.
SRBC	Standard Docket Conditions Contained In Gas Well **Surface Water** Dockets	*	Item 10.	Must report the method of water transport (tanker truck or pipeline) and show that all water withdrawn from surface water sources is transported, stored, injected into a well, or discharged with appropriate controls and treatment to prevent the spread of aquatic nuisance species.
DRBC	Water Code 18 CFR Part 410		2.20.2	The underground water-bearing formations of the DRB, their waters, storage capacity, recharge areas, and ability to convey water shall be preserved and protected.
DRBC	Water Code 18 CFR Part 410		2.20.3	Projects that withdraw underground waters must reasonably safeguard the present and future public interest in the affected water resources.
DRBC	Water Code 18 CFR Part 410		2.20.4	Withdrawals from DRB ground water are limited to the maximum draft of all withdrawals from a ground water basin, aquifer, or aquifer system that can be sustained without rendering supplies unreliable, causing long-term progressive lowering of ground water levels, water quality degradation, permanent loss of storage capacity, or substantial impact on low flows of perennial streams, unless the DRBC decides a withdrawal is in the public interest. In confined coastal plain aquifers, the DRBC may apply aquifer management levels, if any, established by a signatory state in determining compliance with criteria relating to "longterm progressive lowering of ground water levels."
DRBC	Water Code 18 CFR Part 410		2.20.5	The principal natural recharge areas of the DRB shall be protected from unreasonable interference. No recharge sources (ground or surface water) shall be polluted based on water quality standards promulgated by the DRBC or any of the signatory parties.
DRBC	Water Code 18 CFR Part 410		2.20.6	The DRB ground water resources shall be used, conserved, developed, managed, and controlled for the needs of present and future generations, so interference, impairment, penetration, or artificial recharge shall be subject to review and evaluation under the Compact.
DRBC	Water Code 18 CFR Part 410		2.10.1	The DRBC may acquire, operate and control projects and facilities for the storage and release of waters, for the regulation of flows and DRB surface and ground water supplies, for the protection of public health, stream quality control, economic development, improvement of fisheries, recreation, pollution dilution and abatement, the prevention of undue salinity and other purposes. No signatory party may permit any augmentation of flow to be diminished by the diversion of any DRB water during any period in which waters are being released from storage by the DRBC for the purpose of augmenting such flow, except in cases where such diversion is authorized by this compact, or by the DRBC pursuant to, or by the order of a court of competent jurisdiction.

Agency	Document	Article	Regulation Summary
DRBC	Water Code 18 CFR Part 410	2.30.2	The waters of the DRB are limited in quantity and to drought. The exportation of DRB water is discouraged. The DRB waters have limited assimilative capacity to accept substances without significant impacts. Wastewater import that would significantly reduce the assimilative capacity of the receiving DRB stream is discouraged and should be reserved for users within the DRB.
DRBC	Water Code 18 CFR Part 410	2.30.3	Consideration of the importation or exportation of water will be conducted pursuant to this policy and include assessments of the water resource and economic impacts of the project and of all alternatives to any water exportation or wastewater importation project.
DRBC	Water Code 18 CFR Part 410	2.30.4	The DRBC has jurisdiction over exportations and importations of water (Section 3.8 of the Compact, and inclusion within the Comprehensive Plan) as specified in the Administrative Manual - Rules of Practice and Procedure. The applicant shall address those of the items listed below as directed by the DRBC: A. efforts to develop or use and conserve outside resources; B. water resource, economic, and social impacts of each alternative, including the "no project" alternative; D. amount, timing and duration of the proposed transfer and its relationship to DRB hydrologic conditions, and impact on instream uses and downstream waste assimilation capacity; E. benefits to the DRB as a result of the proposed transfer; F. volume of the transfer and its relationship to other specified actions or Resolutions by the DRBC; G. the relationship of the transfer volume to all other diversions; H. other significant benefits or impairments to the DRB as a result of the proposed transfer.
DRBC	Water Code 18 CFR Part 410	2.30.6	The DRBC gives no credit toward meeting wastewater treatment requirements for wastewater imported into the Delaware Basin. Wasteload allocations assigned to dischargers will not include loadings attributable to wastewater importation.
DRBC	Water Code 18 CFR Part 410	2.200.1	DRB water quality will be maintained in a safe and satisfactory condition for...wildlife, fish and other aquatic life.
DRBC	Water Code 18 CFR Part 410	2.350.2	The DRBC will preserve and protect wetlands by: A. minimizing adverse alterations in the quantity and quality of the underlying soils and natural flow of waters that nourish wetlands; B. safeguarding against adverse draining, dredging or filling practices, liquid or solid waste management practices, and siltation; C. preventing the excessive addition of pesticides, salts or toxic materials arising from non-point source wastes; and D. preventing destructive construction activities.
DRBC	Water Code 18 CFR Part 410	2.400.2	The drought of record, which occurred in the period 1961-1967, shall be the basis for planning and development of facilities and programs for control of salinity in the Delaware Estuary.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,1	The DRBC maintains the quality of interstate waters, where existing quality is better than the established stream quality objectives, unless such change is justifiable as a result of necessary economic or social development or to improve significantly another body of water. The DRBC will require the highest degree of waste treatment practicable. No change will be considered which would be injurious to any designated present or future use.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,b	There will be no measurable change in water quality except towards natural conditions in water that has high scenic, recreational, ecological, and/or water supply values. Waters with exceptional values may be classified as either **Outstanding Basin Waters (OBW) or Significant Resource Waters (SRW)**. OBW shall be maintained at their existing water quality. 2) SRW must not be degraded below existing water quality, although localized degradation of water quality may be allowed for initial dilution if the DRBC, after consultation with the state NPDES permitting agency, finds that the public interest warrants these changes, unless a mixing zone is allowed and then to the exten of the mixing zone designated as set forth in this section. If degradation of water quality is allowed for initial dilution purposes, the DRBC, will designate mixing zones for each point source and require the highest possible point source treatment levels necessary to limit the size and extent of the mixing zones. The dimensions of the mixing zone will be based upon an evaluation of (a) site specific conditions, including channel characteristics; (b) the cost and feasibility of treatment technologies; and (c) the design of the dis
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,c	1) Direct discharges of wastewater to **Special Protection Waters (SPW)** are discouraged. New wastewater treatment facilities and substantial alterations to existing facilities that discharge directly to SPW may be approved after the applicant has evaluated all nondischarge/ load reduction alternatives and is unable to implement these alternatives because of technical and/or financial infeasibility. 2) New wastewater treatment facilities and substantial alterations to existing facilities within the drainage area of SPW may be approved after the applicant fully evaluated all natural treatment alternatives and is unable to implement them because of technical and/or financial infeasibility. **For both 1) and 2)** above, the applicant will consider alternatives to all loadings – both existing and proposed – in excess of actual loadings at the time of SPW designation. 3) New wastewater treatment facilities and substantial alterations to existing facilities discharging directly to SRW may be approved only following a determination that the project is in the public interest as that term is defined in Section 3.10.3.A.2.a.5 4) The general number, location and size of future wastewater treatment facilities discharging to OBW (if an
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,d	Addresses emergency systems (standby power facilities, alarms, emergency management plans) for wastewater treatment facilities discharging to SPW. Emergency management plans shall include an emergency notification procedure covering all affected downstream users. The minimum level of wastewater treatment for new wastewate treatment facilities and substantial alterations to existing wastewater treatment facilities that discharge directly to OBW or SRW will be **Best Demonstrable Technology (BDT)** (See rule for chemical analyses results that define BDT.) BDT may be superseded by applicable federal, state or DRBC criteria that are more stringent. BDT for disinfection - ultraviolet light disinfection or an equivalent disinfection process that results in no harm to aquatic life, does not produce toxic chemical residuals, and results in effective bacterial and viral destruction. DRBC may approve effluent trading on a voluntary basis between point sources within the same watershed or between the same Interstate or Boundary Control Points to achieve no measurable change to existing water quality. Regulation discusses facilities within drainage areas of SPW and discharges to OBW and SRW and lists water quality control points and the analyses parameters.
DRBC	Water Code 18 CFR Part 410	3.10.3,A,2,e	1) Projects subject to review under Section 3.8 of the Compact that are located in the drainage area of SPW must submit for approval a Non-Point Source Pollution Control Plan that controls the new or increased non-point source loads generated within the portion of the project's service area which is also located within the drainage area of SPW The plan will state which BMPs must be used to control the non-point source loads. RULE DISCUSSES trade-off plans in detail. It discusses: projects located above major

Agency	Document	Article	Regulation Summary
			surface water impoundments; projects located in municipalities that have adopted and are actively implementing non-point source/stormwater control ordinances, projects located in watersheds where the applicable state environmental agency, county government, and local municipalities are participating in the development of a watershed plan. 2) Approval of a new or expanded water withdrawal and/or wastewater discharge project will be subject to the condition that any new connection to the project system only serve an area(s) regulated by a non-point source pollution control plan which has been approved by the DRBC. 3) Future plans for SPWs non-point source control regulations
DRBC	Water Code 18 CFR Part 410	3.10.3B	DRB waters will not contain substances attributable to municipal, industrial, or other discharges in concentrations or amounts sufficient to preclude the protection of specified water uses. a. The waters shall be substantially free from unsightly or malodorous nuisances due to floating solids, sludge deposits, debris, oil, scum, substances in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, odor of the water, or taint fish or shellfish flesh. b. The concentration of total dissolved solids, except intermittent streams, shall not exceed 133 percent of background. In no case shall concentrations of substances exceed those values given for rejection of water supplies in the United States Public Health Service Drinking Water Standards.
DRBC	Water Code 18 CFR Part 410	3.10.3C	The DRBC designates numerical stream quality objectives for the protection of aquatic life for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Aquatic life objectives for the protection from both acute and chronic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.3D	The DRBC designates numerical stream quality objectives for the protection of human health for the Delaware River Estuary (Zones 2 through 5) which correspond to the designated uses of each zone. Stream quality objectives for protection from both carcinogenic and systemic effects are herein established on a pollutant-specific basis. (See RULE)
DRBC	Water Code 18 CFR Part 410	3.10.4,A	All wastes shall receive a minimum of secondary treatment, regardless of the stated stream quality objective.
DRBC	Water Code 18 CFR Part 410	3.10.4,B	Wastes (exclusive of stormwater bypass) containing human excreta or disease producing organisms shall be effectively disinfected before being discharged into surface bodies of water as needed to meet applicable DRBC or State water quality standards.
DRBC	Water Code 18 CFR Part 410	3.10.4,C	Effluents shall not create a menace to public health or safety at the point of discharge.
DRBC	Water Code 18 CFR Part 410	3.10.4,D	Lists discharge contaminant limits.
DRBC	Water Code 18 CFR Part 410	3.10.4,E	Where necessary to meet the stream quality objectives, the waste assimilative capacity of the receiving waters shall be allocated in accordance with the doctrine of equitable apportionment.
DRBC	Water Code 18 CFR Part 410	3.10.4,F	1. Discharges to intermittent streams may be permitted by the DRBC only if the applicant can demonstrate that there is no reasonable economical alternative, the project is environmentally acceptable, and would not violate the stream quality objectives set forth in Section 3.10.3B.1.a. 2. Discharges to intermittent streams shall be adequately treated to protect stream uses, public health and ground water quality, and prevent nuisance conditions.
DRBC	Water Code 18 CFR Part 410	3.10.5,E	The DRBC will consider requests to modify the stream quality objectives for toxic pollutants based upon site-specific factors. Such requests shall provide a demonstration of the site-specific differences in the physical, chemical or biological characteristics of the area in question, through the submission of substantial scientific data and analysis. The demonstration shall also include the proposed alternate stream quality objectives. The methodology and form of the demonstration shall be approved by the DRBC.
NYSDEC	6 NYCRR Part 608	608.9	(a) Water quality certifications required by Section 401 of the Federal Water Pollution Control Act, Title 33 United States Code 1341(see subdivision (c)of this Section). Any applicant for a federal license or permit to conduct any activity, including but not limited to the construction or operation of facilities that may result in any discharge into navigable waters as defined in Section 502 of the Federal Water Pollution Control Act (33 USC 1362), must apply for and obtain a water quality certification from the department.The applicant must demonstrate compliance with Sections 301-303, 306 and 307 of the Federal Water Pollution Control Act (See RULE.)

* Connotes the indicated regulation pertains directly to invasive or nuisance species. All other regulations reference practices, methods, and actions that are not specifically targeted at reducing or eliminating the transport of invasive species, but nonetheless may indirectly address the issue.

7.5 Protecting Air Quality

7.5.1 Mitigation Measures Resulting from Regulatory Analysis (Internal Combustion Engines and Glycol Dehydrators)

7.5.1.1 NOx

Control Technologies for Natural Gas Engines

Three generic control techniques have been developed for reciprocating engines: parametric controls (timing and operating at a leaner air-to-fuel ratio); combustion modifications such as advanced engine design for new sources or major modification to existing sources (clean-burn cylinder head designs and pre-stratified charge combustion for rich-burn engines); and post-combustion catalytic controls installed on the engine exhaust system. Post-combustion catalytic technologies include selective catalytic reduction (SCR) for lean-burn engines, nonselective catalytic reduction (NSCR) for rich-burn engines, and CO oxidation catalysts for lean-burn engines.

CONTROL TECHNIQUES FOR 4-CYCLE RICH-BURN ENGINES

Nonselective Catalytic Reduction (NSCR) - This technique uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_x. The excess hydrocarbons, CO and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_x to N_2. NO_x reduction efficiencies are usually greater than 90 percent, while CO reduction efficiencies are approximately 90 percent.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of4 percent or less. This includes 4-stroke rich-burn, naturally aspirated engines and some 4-stroke rich-burn, turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.

Pre-Stratified Charge - Pre-stratified charge combustion is a retrofit system that is limited to 4-stroke carbureted natural gas engines. In this system, controlled amounts of air are introduced into the intake manifold in a specified sequence and quantity to create a fuel-rich and fuel-lean zone. This stratification provides both a fuel-rich ignition zone and rapid flame cooling in the fuel-lean zone, resulting in reduced formation of NO_x. A pre-stratified charge kit generally contains new intake manifolds, air hoses, filters, control valves, and a control system.

CONTROL TECHNIQUES FOR LEAN-BURN RECIPROCATING ENGINES

Selective Catalytic Reduction - Selective catalytic reduction is a post-combustion technology that has been shown to be effective in reducing NO_x in exhaust from lean-burn engines. An SCR system consists of an ammonia storage, feed, and injection system, and a catalyst and catalyst housing. Selective catalytic reduction systems selectively reduce NO_x emissions by injecting ammonia (either in the form of liquid anhydrous ammonia or aqueous ammonium hydroxide) into the exhaust gas stream upstream of the catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. For the SCR system to operate properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850F). The temperature range is dictated by the catalyst (typically made from noble metals, base metal oxides such as vanadium and titanium, and zeolite-based material). Exhaust gas temperatures greater than the upper limit (850F) will pass the NO_x and ammonia unreacted through the catalyst. Ammonia emissions, called NH_3 slip, are a key consideration when specifying a SCR system. SCR is most suitable for lean-burn engines operated at constant loads, and can achieve efficiencies as high as 90 percent. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.

Catalytic Oxidation - Catalytic oxidation is a post-combustion technology that has been applied, in limited cases, to oxidize CO in engine exhaust, typically from lean-burn engines. As previously mentioned, lean-burn technologies may cause increased CO emissions. The application of catalytic oxidation has been shown to be effective in reducing CO emissions from lean-burn engines. In a catalytic oxidation system, CO passes over a catalyst, usually a noble metal, which oxidizes the CO to CO_2 at efficiencies of approximately 70 percent for two stroke lean burn engines and 90 percent for four stroke lean burn engines.

(ref-AP-42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Sources)

Control Technologies for Diesel and Dual-Fuel Engines

The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR), which are post-combustion techniques are becoming available. Controls for CO have been partly adapted from mobile sources.

Combustion modifications include injection timing retard (ITR), pre-ignition chamber combustion (PCC), air-to-fuel ratio adjustments, and de-rating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture, which lowers combustion temperature, thereby reducing NO_x emissions. The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.

SULFUR OXIDES

Sulfur oxide emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.

Recent communications with representatives of natural gas producer Chesapeake Energy indicated that contractors that are providing some 80% of the diesel rigs to the industry are using ultra low sulfur fuel (15ppm) because of the reduced availability of the alternative low sulfur fuel.

The proposed revision of 40 CFR Part 63 Subpart ZZZZ "Engine MACT" described in Appendix 17 will mandate the use of ultra low sulfur fuel.

(ref-AP-42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Sources)

7.5.1.2 Natural Gas Production Facilities NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators)

For those area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described above that are located within the UA plus offset and UC boundary, each such unit must be connected, through a closed vent system, to one or more emission control devices. The control devices must: (1) reduce HAP emissions by 95 percent or more (generally by a condenser with a flash tank); or (2) reduce HAP emissions to an outlet concentration of 20 parts per million by volume (ppmv) or less (for combustion devices); or (3) reduce benzene emissions to a level less than 1.0 ton/year). As an alternative to complying with these control requirements, pollution prevention measures, such as process modifications or combinations of process modifications and one or more control devices that reduce the amount of HAP generated, are allowed provided that they achieve the same required emission reductions.

For those area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described above that are located outside of UA plus offset and UC boundaries, each unit must reduce emissions by lowering the glycol circulation rate to be less than or equal to an optimum rate. The optimum rate is determined by the following equation:

$$\text{LOPT} = 1.15 * 3.0 \, \frac{\text{galTEG}}{\text{lb H2O}} * \frac{\{ F*(I - O)\}}{\{ 24\text{hr/day} \}}$$

Where:
LOPT = Optimal circulation rate, gal/hr.
F = Gas flowrate (MMSCF/D).
I = Inlet water content (lb/MMSCF), and
O = Outlet water content (lb/MMSCF).

The constant 3.0 gal TEG/lb H2O is the industry accepted rule of thumb for a TEG-to-water ratio. The constant 1.15 is an adjustment factor included for a margin of safety.

7.5.2 Mitigation Measures Resulting from Air Quality Impact Assessment

The modeling analysis conducted to date and described in Section 6.5.2 supports the following conclusions and possible mitigation measures to assure compliance with ambient air quality standards and other thresholds. Any deviations from the noted measures will require either equivalent mitigation for the particular exceedance or a site specific assessment:

1) Essentially all criteria pollutant impacts are found to meet the applicable PSD increments and ambient standards using the industry supplied emissions data and stack parameters. The annual NO2 impact calculations have incorporated an extension of the off-site compressor stack to a minimum of 7.6m (25ft), as also required by conclusions on non-criteria pollutant impacts. The 24 hour PM 10 and PM2.5 impacts are predicted to be above the corresponding standards, but no simple mitigation measures were indicated. However, a combination of a minimum stack height extension of 3.1m (10ft) for the sources controlling these impacts (the drilling rig engines and the hydraulic fracturing

engines) and the preclusion of public access in close proximity of the well pad area is determined to be one means to alleviate the exceedences. Alternative mitigation measures could be defined by industry to achieve compliance. Thus, the modeling analysis performed to date support the following mitigation measures for the criteria pollutants in order to meet all of the ambient thresholds:

a) the fuel oil to be used in the various operation engines must be limited to the ultra low sulfur content of 15ppm.

b) the compressor stack height must be a minimum of 7.6m (25ft).

c) To eliminate particulate standards exceedences, public access must be precluded from the pad area out to a minimum distance of 500m in all directions by erecting a fence or a comparable measure (e.g. posting of signs is not an acceptable measure). A smaller distance can be defined by refining the background levels or industry can propose alternate measures or controls.

2) The impacts of the non-criteria pollutants associated with the short term venting of “wet” gas, which contains certain VOC species, are well below the corresponding 1 hour guideline concentrations, with the exception of H_2S. For the latter, a simple stack height increase to a minimum of 9.1m (or 30feet) for the flowback vent stack will resolve the exceedance.

3) All of non-criteria pollutant impacts from the combustion sources and the glycol dehydrator are well below the corresponding short term guideline levels. On the other hand, in order for the annual impacts to be below the corresponding annual guideline concentrations, the glycol dehydrator emissions of benzene must be limited to meet NESHAP requirements (i.e. use of condenser) and its stack height must be a minimum of 9.1m (30ft), while the off-site compressor must be equipped with an oxidation catalyst and its stack height must be a minimum of 7.6m (25ft).

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

Finally, these conclusions are contingent on assuring that certain assumptions used in the modeling are verified. For example, there is a need to keep records of glycol use in the dehydrator for benzene emission calculations and operational logs of the various engine usage over a year's period as means to verify the modeling assumptions.

7.5.3 Summary of Air Quality Impacts Mitigation

7.5.3.1 Well Pad

The EAF Addendum will require information regarding stack heights and public access restrictions relative to the well pad. If stack heights shorter than those specified in Table 7.5 are proposed, then information must be attached to the EAF Addendum which demonstrates that other control measures will effectively prevent exceedances for the listed pollutants. Even with the 10-foot stack height for the drilling rig and truck-mounted hydraulic fracturing engines, a physical barrier to public access at least 500 feet from the well pad could be required unless the applicant demonstrates that specific control equipment will be used to further reduce particulate matter emissions during hydraulic fracturing operations.

Table 7.5 – Required Well Pad Stack Heights to Prevent Exceedences

Equipment	Pollutant	Stack Height
Drilling rig and truck-mounted hydraulic fracturing engines	Particulate matter	10 feet NOTE: physical barriers to public access may also required
Flowback vent/flare	H_2S	30 feet NOTE: not required if previous drilling at the same pad has demonstrated that H_2S is not present
Glycol dehydrator	Benzene	30 feet NOTE: Subpart HH compliance as described in Section 7.5.2.2 is also required.

The air dispersion modeling exercise described in Section 6.5.2 also determined that physical barriers to public access 500 feet from the wellsite would prevent exposure to HAPs from flowback water in an on-site reserve pit. However, as discussed elsewhere in this Supplement, uncertainties relative to potential flowback water volume and composition have led the Department to propose that flowback water not be directed to an on-site reserve pit but instead be held on the well pad in tanks prior to shipment to a disposal, treatment or re-use location.

The EAF Addendum will also require the operator to confirm use of ultra-low sulfur fuel (< 15 ppm).

7.5.3.2 Centralized Flowback Water Surface Impoundments

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

7.5.3.3 Off-Site Gas Compressors

The air modeling exercise also determined stack heights for equipment at centralized compressor stations; see Table 7.6. While these are governed by the separate PSC process described in Section 5.16.8, the Department will reference these findings as it participates in that process.

Table 7.6 – Stack Heights for Equipment at Centralized Compressor Stations

Equipment	Pollutant	Stack Height
Glycol dehydrator	Benzene	30 feet NOTE: Subpart HH compliance as described in Section 7.5.2.2 is also required.
Compressor	NO_2 Formaldehyde	25 feet NOTE: must also be equipped with an oxidation catalyst

7.6 Mitigating Greenhouse Gas Emissions

Potential greenhouse gas (GHG) emissions are discussed in Section 6.6, including estimates of total annual emissions of carbon dioxide (CO_2) and methane (CH_4) as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons for expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. The real benefit of the emission estimates comes not with quantifying possible emissions but from the identification and characterization of likely major sources of CO_2 and CH_4 during the anticipated operations. Identification and understanding of the key contributors of GHGs allows mitigation measures and future efforts to be efficiently focused. It was determined from the analysis included in Section 6.6 that ongoing yearly production activities from either a single well project or multi-well pad contribute significantly greater GHGs on a CO_2e basis than do the one-time operations necessary to mobilize, drill and complete wells. The following sections discuss possible mitigation measures for limiting GHGs, with particular emphasis on CH_4 because of its Global Warming Potential (GWP).

7.6.1 General

The United States Environmental Protection Agency's (USEPA) Natural Gas STAR Program is a flexible, voluntary partnership that encourages oil and natural gas companies – both domestically and abroad – to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of CH_4, a potent greenhouse gas and clean energy source.[80] Natural Gas STAR partners can implement a number of voluntary activities to reduce GHG emissions from both exploration and production activities. The Department encourages active participation in the program. An example of a measure that could be included in a greenhouse gas emissions impacts mitigation plan includes:

- Proof of participation in the USEPA's Natural Gas STAR Program to reduce methane emissions (see Appendices 24 and 25)[81]

7.6.2 Site Selection

Site selection directly impacts the number of rig and equipment mobilizations needed to develop a well pad or area. Well operators can limit the generation of CO_2 by limiting vehicle miles traveled (VMT) and fuel consumption. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

---

[80] http://www.epa.gov/gasstar/

[81] http://www.epa.gov/gasstar/join/index.html

- Drilling as many wells as possible on a pad with one rig move,
- Spacing wells for efficient recovery of natural gas,
- Hydraulic fracturing as many wells as possible on a pad with one equipment move, and
- Planning for efficient rig and fracturing equipment moves from one pad to another.

7.6.3 Transportation

Transportation related to sourcing of equipment and materials, including disposal, was identified as a potential contributor of CO_2 emissions. Well operators can limit the generation of CO_2 by limiting VMT and fuel consumption. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Sourcing personnel and equipment from locations within the State or region,
- Using materials that are extracted and/or manufactured within the State or region,
- Recycling fluids at in-state facilities,
- Disposal or processing wastes at in-state facilities including disposal wells, and
- Using efficient transportation engines.

7.6.4 Well Design and Drilling

Well operators can limit GHG emissions during well drilling operations by effectively designing drilling programs. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Extending each lateral wellbore as far as technically and legally possible to reduce the total number of wells required within a spacing unit,
- Spacing the lateral wellbores for efficient recovery of natural gas,
- Re-using drilling fluids,
- Drilling overbalanced to limit/prevent venting and/or flaring of CH4,
- Using materials with recycled content (e.g., well casing, drilling fluids),

- Using efficient rig engines,
- Using efficient air compressor engines for drilling,
- Using efficient exterior lighting,
- Ensuring all flow connections are tight and sealed,
- Whenever possible, flaring methane instead of venting, and
- Performing leak detection surveys and taking corrective actions.

7.6.5 Well Completion

Well completion activities primarily contribute to GHG emissions from the internal combustion engines required for hydraulic fracturing and flaring operations during the flowback period. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Re-using flowback water,
- Using materials with recycled content (e.g., frac fluids),
- Using efficient hydraulic fracturing pump engines,
- Using efficient exterior lighting,
- Limiting flaring during the flowback phase by using reduced emissions completions (REC) equipment (see Appendix 25),
- If allowed by the Public Service Commission (PSC), constructing gathering lines so that the first well on a pad can initially be flowed into a sales line,
- Ensuring all flow connections are tight and sealed,
- Whenever possible, flaring methane instead of venting, and
- Performing leak detection surveys and taking corrective actions.

7.6.6 Well Production

As mentioned above, compared to any of the aforementioned operational phases, the ongoing production phase of any given well is the most significant period and contributor of GHGs, especially CH4. Natural gas compressors which run virtually around-the-clock, produce both

CO_2 and CH_4 emissions. Equipment required to process produced natural gas, specifically the glycol dehydrators (i.e., vents & pumps) and pneumatic devices, generate CH_4 emissions during normal production operations. Examples of measures that could be included in a greenhouse gas emissions impacts mitigation plan include:

- Implementing USEPA's Natural Gas STAR Best Management Practices (BMP) including below:[82]
- Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry[83]
- Reducing Methane Emissions from compressor rod packing systems[84]
- Reducing emissions when taking compressors off-line[85]
- Replacing Glycol Dehydrators with Desiccant Dehydrators[86]
- Replacing gas-assisted glycol pumps with electric pumps[87]
- Optimizing glycol circulation and installing flash tank separators in glycol dehydrators,[88]
- Using efficient compressor engines,
- Using efficient line heaters,
- Using efficient glycol dehydrators,
- Re-using produced waters,
- Ensuring all flow connections are tight and sealed,
- Performing leak detection surveys and taking corrective actions,
- Using efficient exterior lighting, and

[82] http://www.epa.gov/gasstar/tools/recommended.html

[83] http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

[84] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf

[85] http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf

[86] http://www.epa.gov/gasstar/documents/ll_desde.pdf

[87] http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf

[88] http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf

- Using solar-powered telemetry devices.

7.6.7 Mitigating Greenhouse Gas Emissions Impacts - Conclusion

Well operators can reduce their GHG emissions through active participation in the USEPA's Naural Gas STAR Program, and through effective planning and implementation of necessary activities. Supplementary permit conditions for high-volume hydraulic fracturing will include a requirement that the operator construct and operate the site in accordance with a greenhouse gas emissions impacts mitigation plan that may incorporate the above practices and considers, to the extent practicable, any relative Department policy documents. However, at a minimum, the plan must include the list of BMPs planned for implementation at the permitted well site and the first compressor facility receiving the well's production. Partners in USEPA's Natural Gas STAR Program should include proof of their participation and starting date. The operator's greenhouse gas emissions impacts mitigation plan shall be available to the Department upon request.

7.7 Mitigating Impacts from Centralized Flowback Water Impoundments

The potential use of large centralized surface impoundments to hold flowback water as part of a dilution and reuse system is described in Section 5.12.2.1. Potential impacts are discussed throughout Chapter 6 and summarized in Section 6.7. The mitigation measures that are identified in several sections above are summarized here. Conservative mitigation measures are proposed for centralized flowback water surface impoundments because of the following factors:

- The centralized surface impoundments are likely to be significantly larger than the well pad reserve pits,
- The centralized surface impoundments are likely to contain a greater volume of flowback water than is ever present on a well pad at one time,
- The centralized surface impoundments will be in use for longer periods of time than any well pad reserve pit, and
- As explained in Section 5.11.3, conservative measures are warranted because of the limited availability of information regarding flowback water characteristics.

The Department anticipates that, by the time the final SGEIS is published, additional data and analyses will be made public by the Marcellus Shale Committee and the Appalachian Shale Water Conservation and Management Committee. If so, this information and any further information provided to the Department regarding flowback characteristics associated with Marcellus operations in the northern tier of Pennsylvania will be considered during the comment period before the SGEIS is finalized. If sufficient information is not provided before the SGEIS is finalized to support different protocols than are described herein, then any required site-specific environmental reviews in New York must be based on the operator's analysis, reviewed by the Department, of actual flowback data collected within reasonable proximity to the well pads that will be serviced by the proposed surface impoundment.

For SEQRA purposes, a centralized flowback water surface impoundment will be considered part of the project with the first well permit application that proposes its use. All well permit applications proposing use of a centralized flowback water surface impoundment will be considered incomplete until the Department has approved the impoundment. Location and construction of centralized flowback water surface impoundments and associated piping and conveyances will be reviewed pursuant to 6 NYCRR 554.1(c)(1), which requires approval, prior to well permit issuance, of a fluid disposal plan. As part of the application for a well permit, proposals will be reviewed individually to determine the level of SEQRA review, if any, that is required in addition to this Supplement.

The Department will not approve fluid disposal plans that propose centralized flowback water surface impoundments within the boundaries of primary and principal aquifers, unfiltered water supplies, or mapped 100-year floodplains. A site-specific SEQRA determination of significance will be required for any fluid disposal plan that proposes a centralized flowback water surface impoundment in any of the following locations:

- within 1,000 feet of a reservoir;
- within 500 feet of a perennial or intermittent stream, wetland, storm drain, lake or pond; and
- within 300 feet of a private or public water supply well.

To prevent potential impacts summarized in Section 6.7, the Department will apply the following review standards and requirements to proposed centralized flowback water surface impoundments:

1) If dam safety permitting criteria (Figure 5.5) are met, then construction must be in accordance with the Department's technical guidance document, *Guidelines for Design of Dams,* and operation must be in accordance with the Department's document, *An Owner's Guidance Manual for the Inspection and Maintenance of Dams in New York State.*

2) The specific provisions of 6 NYCRR Subpart 360-6 Liquid Storage will provide the overall requirements for flowback impoundments, describing the minimum liner, operational, monitoring and closure requirements.

    a. As provided by subdivision 360-2.14(a), the Department will consider proposals to use alternate liner materials provided the following requirements are met:

        i. High Density Polyethylene geomembranes must have a minimum thickness of 60 mils.

        ii. Linear Low Density Polyethylene geomembranes must have a minimum thickness of 40 mils.

        iii. Polyvinyl Chloride must have a minimum thickness of 30 mils and must be double hot wedge seamed with all field seams tested using the air channel test.

        iv. Certain reinforced geomembrane polymers also may be considered, in light of the durable nature of scrim-reinforced geomembranes which makes them more ideal for exposed applications.

    b. The lowermost composite liner may be designed with a geosynthetic clay liner in lieu of the two-foot thick clay barrier that is specified by Section 360-6.5.

3) The required fluid disposal plan must demonstrate that piping and conveyances used to convey flowback water to or from the centralized surface impoundment will be constructed of suitable materials, maintained in a leak-free condition, regularly inspected and operated using all appropriate spill control and stormwater pollution prevention practices.

4) The practices described in Section 7.4.1 of this Supplement must be employed to mitigate impacts related to invasive species.

5) The inner slopes of the impoundment that may come in contact with fluctuating levels of flowback water must be kept clear of vegetation.

6) The impoundment must be fenced and netting should be considered to prevent access by waterfowl or other wildlife.

7) Mitigation of potential air impacts will be determined by site-specific consideration of proposed additives, flowback analyses submitted by the operator from wells using the same additive mix, the duration and use of the impoundment, whether it will be covered and the distance surrounding the impoundment within which public access is restricted by a physical barrier such as a fence.

Many of the above practices address impacts that would be most effectively mitigated by use of covered tanks instead of open surface impoundments for centralized flowback water facilities. The provisions of 6 NYCRR Section 360-6.3 provide the regulatory standards that would apply to review of a fluid disposal plan submitted pursuant to 6 NYCRR 554.1(c)(1) that proposes the use of a centralized tank facility to manage flowback water.

7.8 Mitigating Naturally Occurring Radioactive Material (NORM) Impacts

7.8.1 State and Federal Responses to Oil and Gas Norm[89]

Discovery of elevated concentrations of NORM levels in other areas outside of New York in the 1980s led to a series of state and private investigations of the issue. State responses to the potential of elevated oil and gas NORM range from no action (barring self-reported problems) to decisions for further study, to implementation of new formal regulations and guidance documents. To date, no state has assessed the occurrence of NORM from longer duration drilling operations at multi-well sites and larger accumulations of shale cuttings from horizontal drilling. NORM is not subject to direct federal regulation (except its transport) under either the AEA or LLRWPA, and exploration and production (E&P) wastes are specifically exempt from regulation under Subtitles D and C of RCRA (LA Office of Conservation, 2009); however, NORM is regulated indirectly at the federal level through potential environmental impacts to drinking water (SDWA) and cleanup of abandoned hazardous waste sites (CERCLA and NCP).

The State of Louisiana was the first state to implement an oil and gas NORM regulatory program, and its program remains one of the most comprehensive to date. The Louisiana Department of Environmental Quality (LADEQ) has implemented a program that includes the identification, use, possession, transport, storage, transfer, decontamination, and disposal of oil and gas NORM to address the protection of human health and the environment. The primary NORM regulations are found in LAC 33:XV, Chapter 14: “Regulation and Licensing of

[89] Alpha, p. 2-44 et seq.

Naturally Occurring Radioactive Material (NORM)." A Memorandum of Understanding (MOU) between the LADEQ and the Louisiana Department of Natural Resources (LDNR) addresses the responsibilities of the two agencies with respect to E&P wastes contaminated with NORM.

Section 1403 of the Louisiana Administrative Code defines NORM as "any nuclide that is radioactive in its natural physical state (i.e. not man-made), but not including source, by-product, or special nuclear material." This broad definition includes much more than just E&P NORM. The action levels provided in Section 1404 for E&P equipment and land contaminated by NORM are provided in the following list. The statute does not apply to levels below those listed.

- NORM, NORM Waste, and NORM contaminated material > 5pCi/g above background of Ra-226 or Ra-228, or > 150 pCi/g of any other NORM nuclide.
- Equipment > 50 microroentgens per hour (μR/hr) at any accessible point
- Land averaged over any 100 square meters with no single noncomposited sample to exceed 60 pCi/g of soil
    - > 5 pCi/g above background of Ra-226 or Ra-228, averaged over the first 15 cm, and 15 pCi/g above background over each subsequent 15 cm; or
    - > 30 pCi/g of Ra-226 or Ra-228, averaged over 15 cm depth increments, provided the total effective dose equivalent from the contaminated land does not exceed 0.1 rem/year.

Louisiana follows the USEPA exemption of oil and gas produced waters as hazardous waste under RCRA, but understands that these fluids may contain substances harmful to human health and the environment (e.g. NORM). The Injection and Mining Division of the Louisiana Office of Conservation (LOC) regulates the subsurface injection of produced waters in compliance with the federal Underground Injection and Control (UIC) program established under the SDWA. The E&P Waste Management Section of the Environmental Division of the LOC regulates commercial E&P waste storage, treatment and disposal facilities and coordinates all UIC enforcement actions brought against Class II injection wells.

Section 1412 allows the treatment, transfer, and disposal of NORM wastes in accordance with the following:

- by transfer to a land disposal facility licensed by Louisiana Department of Environmental Quality (LADEQ), NRC, and an agreement state, or a licensing state;

- by alternate methods authorized by the LADEQ in writing upon application or upon LADEQ's initiative;

- For E&P waste containing NORM at concentrations not exceeding 30pCi/g of Ra-226 or Ra-228, by transfer to an E&P waste commercial facility regulated by the DNR for treatment, if certain conditions are met by the facility; and

- For E&P waste containing concentrations of NORM in excess of the limits in Subsection 1404-a.1, but not exceeding 200 pCi/g Ra-226 or Ra-228 and daughter products, by treatment at E&P waste commercial facilities specifically licensed by LADEQ for such purposes.

Chapter 14 of LAC 33:XV also presents specifics of NORM surveys (Section 1407); worker protection (Section 1411); licensing/permitting (Section 1408); removal/remediation (see licensing and permitting); storage (Sections 1414 through 1416); transfer for continued use; and release of sites, materials and equipment for unrestricted use (Section 1417).

The State of Texas has also developed comprehensive NORM regulatory programs. NORM is regulated in Texas under the Texas Radiation Control Act by three separate agencies: The Texas Department of State Health Services (TDSHS); The Railroad Commission of Texas (TXRRC); and the Texas Commission on Environmental Quality (TCEQ). The Radiation Control Program within the Radiation Safety Licensing Branch of TDSHS regulates the use, treatment, and storage of NORM under 25 Texas Administrative Code §289.259 "Licensing of Naturally Occurring Radioactive Material." The TXRRC regulates the disposal of oil and gas NORM under 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632; "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes. Performance of NORM decontamination, and disposal by the owner through on-site land farming and/or injection well disposal is under the TXRRC's purview. Currently, TDSHS oil and gas NORM waste is defined as anything that constitutes, is contained in, or has contaminated oil and gas waste and exceeds the TDSHS exemption level of 50 μR/hr or has a concentration of 50 pCi/g. This includes E&P equipment, and scale deposits in equipment, but not natural gas or gas products or produced waters, which are exempt. NORM contaminated equipment must be identified using specified radiation survey equipment compliant with TDSHS regulations. Persons who are involved with the disposal of oil and gas NORM must comply with provisions of the TDSHS regulation 25TAC §289.202 including:

- Radiation protection program;
- Occupations dose control;
- Surveys and monitoring;
- Signs and labels; and
- Record keeping.

O&G NORM disposal methods that are specifically prohibited by Chapter 4, Subtitle F, §4.611 include:

- Discharge to surface or groundwater;
- Spreading on public roads; and
- Burial or land farming except on lease where generated by rule.

All other disposal methods require permits. The Technical Permitting Section of the Oil and Gas Division of the TXRRC issues permits for injection well disposal of produced waters which contain dissolved NORM. The permits are in full compliance with the UIC Class II well regulations as defined under the SDWA.

7.8.2 Regulation of NORM in NYS

In New York State, the handling of radioactive material is regulated. Requirements for radioactive materials licensing, excluding medical and educational uses in New York City and entities under exclusive federal jurisdiction, are in the State Sanitary Code, Chapter 1, Part 16 (10 NYCRR 16) and Industrial Code Rule 38 (12 NYCRR 38). The New York State Department of Health is the licensing agency, and it enforces both Part 16 and Code Rule 38. Requirements for environmental discharges, waste shipment and disposal, or environmental cleanup are regulated by the NYS Department of Environmental Conservation (DEC) under its 6 NYCRR Part 380 series of regulations. There are also restrictions on disposal of radioactive materials in 6 NYCRR Part 360.

The overall licensing requirement for radioactive material, §16.100 of the State Sanitary code states, in part, that "no person shall transfer, receive, possess or use any radioactive material except pursuant to a specific or general license issued under this Part." Exemptions to the overall requirement are listed in Part 16, Appendix 16-A. In summary, any person is exempt from the requirements to the extent that such person transfers, receives, possesses or uses products or materials containing radioactive material in concentrations and quantities not in excess of those listed in the accompanying tables. Where multiple radionuclides are present, the sum of the ratios shall not exceed unity (one).

The discharge of radioactive material into the environment is regulated by DEC. NORM contained in the discharge of hydro-fracturing fluids or production brine may be subject to discharge limitations specified in Part 380. Effluent discharges cannot exceed the radionuclide-specific values established in Part 380-11.7. For Ra-226, this value is 6E-8 μCi/ml, or 60 pCi/l.

Analytical results from initial sampling of production brine from vertical gas production wells in the Marcellus formation have been reviewed and suggest that the potential for NORM scale buildup and other NORM waste may require licensing. The results also indicate that production water may be subject to discharge limitations established in Part 380.

Existing data from drilling in the Marcellus formation in other States, and from within NYS for wells that were not hydraulically fractured, shows significant variability in NORM content. This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within NYS are used to assess the extent of this variability. During the initial Marcellus development efforts, sampling and analysis will be undertaken in order to assess this variability. These data will be used to determine whether additional mitigation is necessary to adequately protect the public health and environment of the State of New York.

In order to determine which gas production facilities may be subject to the licensing and environmental discharge requirements, radiological surveys and measurements are necessary including radiation exposure rate measurements of areas of potential NORM contamination, accessible piping, tanks or other equipment that could contain NORM scale buildup. Facilities that possess NORM wastes or piping, tanks or other equipment with elevated radiation levels may need a radioactive materials license. Further, any discharge of effluents into the environment will need to be tested for NORM concentrations prior to discharge.

7.9 Protecting Visual Resources

7.9.1 Pad Siting[90]

As stated in 1992, many of the potential negative impacts of gas development hinge on the location chosen for the well and the techniques used in constructing the access road and well site. Before a drilling permit can be issued, DEC staff must ensure that the proposed location of the well and access road complies with the Department's spacing regulations and siting restrictions. To assist in this process, DEC staff now has access to Policy Guidance Document DEP-00-2, entitled: "Assessing and Mitigating Visual Impacts."

By applying the regulations and siting restrictions along with the guidance provided in DEP-00-2 as appropriate to well pad applications, it will be possible to avoid significant aesthetic impacts.

Specific visual impacts mitigation measures that should be considered include the following:

- Avoid locating rigs and structures so they will interrupt or obscure views of crestlines or ridgelines.
- In addition to siting the structures sensitively, consider how the building design (height, massing, etc.) will affect the visual impact of the site.
- Locate structures to have the least impact on views from surrounding properties.
- In grading and development, preserve salient natural features such as natural terrain, trees and groves, waterways and other similar resources; keep cut and fill operations to a minimum and ensure conformity to existing topography to the extent practical.

7.9.2 Lighting

Examples of other visual impacts mitigation techniques that should be considered involve lighting and could include:

- Directing site lighting downward and internally to the extent possible, and

[90] NTC, pp. 17-18

- Minimizing glare on public roads and adjacent buildings within a specified distance.
- Avoiding "uplights" and wall-washes, as well as lighting where the bulb is visible from the fixture.
- To the maximum practical extent, installing lighting fixtures so they do not cast light on the neighboring properties.

Safety of well site workers must be considered with respect to lighting techniques.

7.9.3 Reclamation

Well pads will be more substantially constructed than was addressed in 1992. A significant amount of crushed stone is brought in and compacted to stabilize the pad and access road to accommodate the equipment and truck traffic. As a result, it would be beneficial in reducing long term visual impacts if the 1992 GEIS topsoil conservation and redistribution practices required upon final plugging and abandonment in agricultural districts were required for all well pads.[91] The specific procedures are:

1) Strip-off and set aside topsoil during construction
2) Protect stockpiled topsoil from erosion and contamination
3) Cut well casing to a safe buffer depth of 4 feet below the surface
4) Paraplow the area before topsoil redistribution if compaction has occurred
5) Redistribute topsoil over disturbed area during site reclamation

The United States Bureau of Land Management's *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* has additional reclamation procedures that would be beneficial to mitigate visual impacts.[92] They include:

1) Re-Vegetation – Disturbed areas should be re-vegetated after the site has been satisfactorily prepared prepared with native perennial species or other plant materials specified by the surface management agency or private surface owner; site preparation should include re-spreading topsoil to an adequate depth for successful re-vegetation.

[91] NTC, p. 18

[92] NTC, p. 18

2) Pipeline Reclamation – Reclamation of pipelines includes re-contouring to the original contour, seeding, and controlling for noxious weeds.

3) Well Site Reclamation – to achieve final reclamation of an abandoned well site, the area should be re-contoured to blend into the contour of the surrounding landform, stockpiled topsoil evenly redistributed, and the site re-vegetated.

4) Road Reclamation – Reclamation of roads includes re-contouring the road to the original contour, seeding, and controlling for noxious weeds.

7.9.4 Protecting Visual Resources - Conclusion

The 1992 GEIS conclusion was that visual impacts from gas drilling and completion activities are primarily minor and short-term, and vary with topography, vegetation, and distance to viewer. It also found that both temporary disruptions of scenic vistas and long term changes in the landscape with the installation of production facilities will occur if the well is economically viable. Given that the visual issues are similar for horizontal drilling with high volume hydraulic fracturing these findings are still relevant. The most significant disruptions will be of a longer duration, particularly for multi-well pads, but they are still short term. The positive benefit of multi-well pads, as discussed previously, is that there will be fewer of them.[93]

Since visual impacts are most effectively addressed at the siting and design phase, it is important that the pad be properly located and planned. Horizontal drilling provides the flexibility to locate the pad in the best possible location and the utilization of multi-well pads will reduce the number of visual impacts in an area. New York State DEC guidance document "DEP-00-02 Assessing and Mitigating Visual Impacts" along with a site plan should be utilized for this purpose. Additionally, the applicant is encouraged to review any applicable local land use policy documents with the understanding that DEC retains authority to regulate gas development.[94]

Supplementary permit conditions for high-volume hydraulic fracturing will include a requirement that the operator construct and operate the site in accordance with a visual impacts mitigation plan that incorporates the above practices and considers, to the extent practicable, local land use policy documents. Municipalities are encouraged to identify and/or map other

---

[93] NTC, pp. 18-19

[94] NTC, p. 19

areas of high visual sensitivity and share this information with operators so they can potentially incorporate additional aesthetic mitigations into their visual impacts mitigation plans.

The operator's visual impacts mitigation plan shall be available to the Department upon request. The Department may require use of the Visual EAF Addendum and add further, site-specific visual mitigation requirements to individual permits if necessary to alleviate impacts to the visual resources listed in Section 2.4.11.

7.10 Mitigating Noise Impacts

7.10.1 Pad Siting[95]

Noise is best mitigated by distance. The further from receptors the lower the impact. The second level of noise mitigation is direction. Directing noise generating equipment away from receptors greatly reduces associated impacts. Timing also plays a key role in mitigating noise impacts. Scheduling the more significant noise generating operations during daylight hours provides for tolerance that may not be achievable during the evening hours.

As stated in 1992, many of the potential negative impacts of gas development hinge on the location chosen for the well and the techniques used in constructing the access road and well site. Before a drilling permit can be issued, DEC staff must ensure that the proposed location of the well and access road complies with the Department's spacing regulations and siting restrictions. To assist in this process DEC staff now has access to Policy Guidance Document DEP-00-1, entitled "Assessing and Mitigating Noise Impacts."

7.10.2 Access Road[96]

With the extensive trucking and associated noise that is involved with water transportation for high volume hydraulic fracturing, attention should be given to the location of the access road. When appropriate, it should be located as far as practical from occupied structures and places of assembly. The purpose is to protect non-lease holders from noise impacts associated with trucking that conflict with their property use.

[95] NTC, pp. 11-12

[96] NTC, p. 12

7.10.3 Multi-Well Pads

As discussed in the 1992 GEIS, moderate to significant noise impacts may be experienced within 1,000 feet of a well site during the drilling phase.[97] With the extended duration of drilling and other activities involved with multi-well pads, it is recommended that the pad not be located closer than 1,000 feet to occupied structures and places of assembly. When this threshold is infringed upon, DEC can add appropriate mitigating conditions to the permit if necessary. [98] Examples of noise mitigation techniques that can be implemented as site-specific permit conditions include the following:

- requirement for ambient noise level determination prior to operations;
- specified daytime and nighttime noise level limits and periodic monitoring thereof;
- placement of tanks, trailers, topsoil stockpiles or hay bales between the noise sources and receptors,
- use of noise reduction equipment such as hospital mufflers, exhaust manifolds or other high-grade baffling,
- limitation of drill pipe and workstring cleaning ("hammering") to certain hours,
- scheduling of bit trips and running of casing during certain hours to minimize noise from elevator operation,
- orientation of high-pressure discharge pipes away from noise receptors,
- placement of air relief lines and installation of baffles or mufflers on lines,
- limitation of cementing operations to certain hours,
- use of higher or larger diameter stacks for flare testing operations and
- placement of redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition.

Many of these mitigation techniques have been successfully applied, when necessary, at wells drilled in New York. In addition, based upon the Department's recommendations, these

[97] GEIS, p. 8-11

[98] NTC, p. 12

mitigation measures have been incorporated into Environmental Assessments prepared by the Federal Energy Regulatory Commission for proposed natural gas storage projects in New York, contributing to that agency's findings the proposed projects would have no significant environmental impact.

7.10.4 Mitigating Noise Impacts - Conclusion

As discussed in the 1992 GEIS, temporary, short-term noise impacts will vary with the presence of topographic or vegetative barriers such as hills, trees and tall grass or shrubs. Drilling operations are the noisiest phase of development and usually continue 24 hours a day. Noise sources during the drilling phase include various drilling rig operations, pipe handling, compressors, and operations of trucks, backhoes, tractors and cement mixing. In most instances, the closest receptor is the residence of the property owner where the well is located and the owner has agreed to the disturbance by entering into a voluntary lease agreement with the well operator. Nevertheless, when necessary because of nearby receptors (regardless of lease status), noise impacts can be mitigated by a combination of site layout to take advantage of existing topography and special permit conditions.

The 1992 GEIS found that there were unavoidable negative noise impacts for those living in close proximity to a drill site. These were determined to be short term and could be mitigated with siting restrictions and setback requirements. Given that the noise issues have been found to be similar for horizontal drilling with high volume hydraulic fracturing these findings are still relevant. The extended time period does make control of the noise impacts, while still temporary, essential. Since noise control is most effectively addressed at the siting and design phase it is important that the pad be properly located and planned, and horizontal drilling provides the flexibility to accommodate this. New York State DEC guidance document "DEP-00-01 Assessing and Mitigating Noise Impacts" along with a site plan should be utilized for this purpose. Additionally, the applicant is encouraged to review any applicable local land use policy documents with the understanding that DEC retains authority to regulate gas development.[99]

Supplementary permit conditions for high-volume hydraulic fracturing will include the following requirements to mitigate potential noise impacts:

---

[99] NTC, p. 13

1) Unless otherwise required by private lease agreement, the access road must be located as far as practical from occupied structures, places of assembly and unleased property and

2) The well operator must operate the site in accordance with a noise impacts mitigation plan that incorporates specific practices and, to the extent practicable, local land use policy documents.

The operator's noise impacts mitigation plan shall be available to the Department upon request. Additional, site specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures and places of assembly.

7.11 Mitigating Road Use Impacts

Under New York State Highway Vehicle Traffic Laws, local municipalities retain control over their roads. This makes it important for municipalities to monitor the NYSDEC web site for information regarding gas development in their areas. Local governments (County, Town and Village) should be proactive in exercising their authority under New York State Highway Vehicle Traffic Laws. This would include the completion of a road system integrity study to potentially assess fees for maintenance and improvements.[100] The applicant should attempt to obtain a road use agreement with the municipality or document the reasons for not obtaining one. When there is no agreement, operators should develop a trucking plan that includes estimated amount of trucking, hours of operations, appropriate off road parking/staging areas, and routes for informational purposes.

Examples of measures that could be included in a road use agreement or trucking plan include:

- route selection to maximize efficient driving and public safety,
- avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods,
- coordination with local emergency management agencies and highway departments,
- upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites,
- advance public notice of any necessary detours or road/lane closures,

[100] NTC, p. 22

- adequate off-road parking and delivery areas at the site to avoid lane/road blockage, and
- use of rail or temporary pipelines where feasible to move water to and from well sites.

Supplementary permit conditions for high-volume hydraulic fracturing will re-emphasize that issuance of a well permit does not provide relief from any local requirements authorized by or enacted pursuant to the NYS Vehicle and Traffic Law. The permit conditions will additionally require the following:

1) Prior to site disturbance, the operator shall submit to the Department, for informational purposes only, a copy of any road use agreement between the operator and municipality.

2) If no road use agreement has been reached, the operator shall file its trucking plan with the Department, for informational purposes only, along with documentation of its efforts to reach a road use agreement.

7.12 Mitigating Community Character Impacts

Based on NTC Consultants' evaluation for NYSERDA, Section 6.12 identified trucking (i.e., road use), land use changes and environmental justice as community character impacts requiring discussion in this Supplement.

7.12.1 Trucking

One of the largest and most obvious potential impacts of the proposed activity on community character is the issue of trucking to support high-volume hydraulic fracturing. [101] While local authorities retain control over local roads, the Department strongly encourages operators and municipalities to attain road use agreements. The road use agreement, or the operator's trucking plan if no agreement is reached, will be on file with the Department. The Department encourages the use of mitigation measures listed in Section 7.11, along with others deemed prudent by the local governing authority.

7.12.2 Land Use

As stated in Section 6.12.1, the multi-well pad development method "will reduce the cumulative changes to the host community, and should minimize loss or fragmentation of habitats,

[101] NTC, p. 23

agricultural areas, forested areas, disruptions to scenic view sheds, and the like."[102] Nevertheless, the Department recognizes the concern that local communities have regarding the scale and potential effects of the proposed activity; therefore, the EAF Addendum submitted with each well permit application will require the applicant to attest to having reviewed any existing comprehensive, open space and/or agricultural plan or similar policy document(s). Whenever possible, full consideration should be given to locating the well pad in an area that has been previously disturbed.

7.12.3 Environmental Justice

As stated in Section 6.12.2, the current "SGEIS/SEQRA process provides opportunity for public input and the resulting permitting procedures will apply statewide and provide equal protection to all communities and persons in New York."[103] Therefore, no additional procedures or mitigation measures are necessary to address environmental justice with respect to the proposed activity.

7.13 Mitigating Cumulative Impacts

Mitigation of cumulative impacts associated with water withdrawal for hydraulic fracturing is discussed in Section 7.1.1.8.

Regarding other types of cumulative impacts, as determined by NTC in its study for NYSERDA and paraphrased in Section 6.13.2.1, "The rate of development cannot be predicted with any certainty ... Nor is it possible to define the threshold at which development results in unacceptable adverse noise, visual and community character impacts… There is no way to objectify these inherently subjective perspectives [and] …there is no sound basis for an administrative determination limiting the shale development at this time.

The appropriate approach for minimizing cumulative impacts associated with noise, aesthetics, traffic and community character, therefore, is to encourage and adhere to the following practices:

- careful siting of well pads,

---

[102] NTC, p. 23

[103] NTC, p. 23

- use by the operators of site-specific visual and noise impact mitigation plans,
- negotiation of road use agreements with the appropriate local governing authorities, and
- recognition of and, to the extent practical, attention to local planning documents and policies.

Contents

Chapter 8 PERMIT PROCESS AND REGULATORY COORDINATION

8.1 Interagency Coordination

Table 8.1, together with Table 15.1 of the GEIS, shows the spectrum of government authorities that oversee various aspects of well drilling and hydraulic fracturing. The GEIS should be consulted for complete information on the overall role of each agency listed on Table 15.1. Review of existing regulatory jurisdictions and concerns addressed in this Supplement identified the following additional agencies that were not previously listed and have been added to Table 8.1:

- New York State Department of Health (NYSDOH)
- US & NYS Departments of Transportation (USDOT & NYSDOT)
- Office of Parks, Recreation and Historic Preservation (OPRHP)
- New York City Department of Environmental Protection (NYCDEP)
- Susquehanna and Delaware River Basin Commissions (RBCs)

Following is a discussion on specific, direct involvement of other agencies in the well permit process relative to high-volume hydraulic fracturing.

8.1.1 Local Governments

ECL §23-0303(2) provides that DEC's Oil, Gas and Solution Mining Law supersedes all local laws relating to the regulation of oil and gas development except for local government jurisdiction over local roads or the right to collect real property taxes. Likewise, ECL §23-1901(2) provides for supercedure of all other laws enacted by local governments or agencies concerning the imposition of a fee on activities regulated by Article 23.

8.1.1.1 SEQRA Participation

For the following actions which were found in 1992 to be significant or potentially significant under SEQRA, the process will continue to include all opportunities for public input normally provided under SEQRA:

- Issuance of a permit to drill in State Parklands.
- Issuance of a permit to drill within 2000 feet of a municipal water supply well.
- Issuance of a permit to drill that will result in disturbance of more than 2.5 acres in an Agricultural District.

Based on the recommendations in this Supplement, the following additional actions will also include all opportunities for public input normally provided under SEQRA:

- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed shallower than 2,000 feet anywhere along the entire proposed length of the wellbore.
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed where the top of the target fracture zone at any point along the entire proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed and the fluid disposal plan required by 6 NYCRR 554.1(c)(1) includes use of a centralized flowback water surface impoundment that has not been previously approved by the Department.
- Issuance of a permit to drill the first well when high-volume hydraulic fracturing is proposed on a well pad within 300 feet of a reservoir, reservoir stem or controlled lake.[1]

[1] The terms "reservoir stem" and "controlled lake" as used here are only applicable in the New York City Watershed, as defined by NYC's Watershed rules and regulations. See Section 2.4.4.3.

- Issuance of a permit to drill the first well when high-volume hydraulic fracturing is proposed on well pad within 150 feet of a private water well, domestic-use spring, watercourse, perennial or intermittent stream, storm drain, lake or pond.[2]

- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed and the source water involves a surface water withdrawal not previously approved by the Department that is not based on the Natural Flow Regime Method as described in Chapter 7.

- Issuance of a permit to drill any well subject to Article 23 whose location is determined by NYCDEP to be within 1,000 feet of subsurface water supply infrastructure.

8.1.1.2 NYCDEP

The Department will continue to notify NYCDEP of proposed drilling locations in counties with subsurface water supply infrastructure to enable NYCDEP to identify locations in proximity to infrastructure that might require site-specific SEQRA determinations. In addition, permits issued in the NYC Watershed will specify by permit condition that NYCDEP must be included in the operator's notification required by ECL §23-0305(13) prior to commencement of operations.

8.1.1.3 Notification to Town Supervisors

ECL §23-0305(13) requires that the permittee notify any affected local government and surface owner prior to commencing operations. Many local governments have requested notification earlier in the process, although it is not required by law or regulation. Information required to track well permit applications is updated daily on the Department's public website. Because of the high level of interest and the community character concerns discussed in Chapter 6, particularly road use, the Department will provide initial Town government notification upon receipt of the first application for high-volume hydraulic fracturing in any town. The letter will be addressed to the town supervisor as identified at http://www.orps.state.ny.us/cfapps/MuniPro/index.cfm, and will include the following:

1) Brief description of permitting process;

2) Explanation that the letter is a notification for purposes of local coordination of jurisdictional issues (e.g., road use), not a SEQRA notice;

---

[2] The term "watercourse" as used here is only applicable in the New York City Watershed, as defined by NYC's Watershed rules and regulations. See Section 2.4.4.3.

3) Pertinent website links, including SGEIS, mapping applications and various lookup tables; and

4) Instructions for using the website to track well status and future applications. These instructions are also included in this Supplement as Appendix 26. The website is not restricted to government officials, but is public and can also be used by citizens with Internet access to track well status and permit applications. Division staff welcomes input from the surface owner and neighbors during the application review, and may impose specific permit conditions to address environmental concerns if appropriate.

8.1.1.4 Local Floodplain Development Permits

Local jurisdiction over development activities in 100-year floodplains is explained in Chapter 2. As set forth in Chapter 7 and the proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, the operator will be required to obtain any required local floodplain development permit prior to site disturbance.

8.1.1.5 Road Use Agreements

The Department strongly encourages operators to attain road use agreements with governing local authorities. The issuance of a permit to drill does not relieve the operator from responsibility to comply with any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Though the Department does not have the authority to require, review or approve road use agreements or trucking plans, the proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing require a road use agreement or trucking plan to be filed with the Department for informational purposes prior to site disturbance.

8.1.1.6 Local Planning Documents

The Department's exclusive authority to issue well permits supercedes local government authority relative to well siting. However, the EAF Addendum will require the applicant's affirmation of having reviewed local planning documents such as comprehensive, open space or agricultural plans. The Department strongly encourages operators to consult with local governments regarding any existing local plans, and – to the maximum extent practicable – site operations accordingly.

8.1.1.7 County Health Departments

As explained in Chapter 15 of the GEIS and Chapter 7 of this document, county health departments are the most appropriate entity to undertake initial investigation of water well complaints. Therefore, the Department proposes that county health departments receive copies of the required baseline and monitoring analyses of residential water wells in proximity to well pads where high-volume hydraulic fracturing occurs. Furthermore, the Department proposes that county health departments retain responsibility for initial response to most water well complaints, referring them to the Department when other causes have been ruled out. The exception to this is when a complaint is received while active operations are underway within a specified distance; in these cases, the Department will conduct a site inspection and will jointly perform the initial investigation along with the county health department.

8.1.2 State

Except for the Public Service Commission relative to its role regarding pipelines and associated facilities (which will continue; see Chapter 5), no State agencies other than DEC are listed in GEIS Table 15.1. The New York State Departments of Health (DOH) and Transportation (DOT), along with the Office of Parks, Recreation and Historic Preservation are listed in Table 8.1 and will be involved as follows:

- *DOH:* Potential future and ongoing involvement in review of new proposed hydraulic fracturing additives, NORM issues, and assistance to county health departments regarding water well investigations and complaints.

- *DOT*: Not directly involved in well permit reviews, but have regulations regarding intrastate transportation of hazardous chemicals found in hydraulic fracturing additives (see Chapter 5).

- *OPRHP:* In addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRPHP will also review locations of related facilities such as surface impoundments and treatment plants.

8.1.3 Federal

The United States Department of Transportation is the only newly listed federal agency. As explained in Chapter 5, the US DOT regulates transportation of hazardous chemicals found in fracturing additives and has also established standards for containers. Roles of the other federal agencies shown on Table 15.1 will not change.

8.1.4 River Basin Commissions

SRBC and DRBC are not directly involved in the well permitting process, and the Department will gather information related to proposed surface water withdrawals that are identified in well permit applications. However, the Department will continue to participate on each Commission to provide input and information regarding projects of mutual interest. DRBC has asserted jurisdiction to approve natural gas well siting and drilling in the Delaware River Basin; the Department will continue to seek cooperation and to avoid any unnecessary regulatory duplication.

8.2 Intra-DEC

8.2.1 Well Permit Review Process

The Division of Mineral Resources (DMN) will maintain its lead role in the review of Article 23 well permit applications, including review of the fluid disposal plan that is required by 6 NYCRR 554.1(c)(1). The Divisions of Air Resources (DAR); Fish, Wildlife and Marine Resources (DFWMR); Solid and Hazardous Materials (DSHM) and Water (DOW) will have advisory roles relative to various aspects of proposed centralized flowback water surface impoundments. DSHM will also have an advisory role regarding cuttings and pit liner disposal for wellbores drilled on mud, DFWMR will have an advisory role regarding invasive species control and DAR will have an advisory role with respect to applicability of various air quality regulations and effectiveness of proposed emission control measures.

8.2.1.2 Required Hydraulic Fracturing Additive Information

As set forth in Chapter 5, NYSDOH reviewed information on 260 unique chemicals present in 197 products proposed for hydraulic fracturing of shale formations in New York, categorized them into chemical classes, and did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS. The regulatory discussion in Chapter 5 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explains why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact. Chapters 6 and 7 include discussion of how setbacks, inherent mitigating factors, and a myriad of regulatory controls protect surface waters. Chapter 7 also proposes a water well testing protocol using indicators that are independent of specific additive chemistry.

The only potential exposure pathway to fracturing additives identified by this Supplement is via air emissions from uncovered surface impoundments used to contain flowback water. Chemistry dictates the extent of required controls, including the distance within which ambient air thresholds are exceeded and public access must be restricted. Therefore, the Department proposes that full chemical disclosure be required with applications that propose the use of open surface impoundments. Products listed in Table 5.3 require no additional disclosure, but the application materials will have to specify their planned concentrations in the fracturing fluid.

The Department recognizes that flowback water chemistry may be preferable for determining impoundment emissions, but to date Department staff has not seen any flowback water analyses that tested for all of the chemicals and compounds that could be present. Flowback water analyses used for this purpose would have to be based on the exact same fracturing additive mix as proposed for all well pads that would use the impoundment, and the Department would have to approve the sampling protocol to ensure that the analysis is representative of the fluid that would be held in the impoundment.

For well permit applications that do not propose use of open surface impoundments, the Department proposes to require identification of additive products and proposed percent by weight of water, proppants and each additive. This will allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figure 5.3. This Supplement has not identified any potential impact other than impoundment emissions that requires full compositional disclosure to the Department for such water-based solutions.

8.2.2 Other DEC Permits and Approvals

The Division of Environmental Permits (DEP) manages most other permitting programs in the Department and is therefore shown in Table 8.1as having primary responsibility for wetlands permitting, review of new in-state industrial treatment plants, and injection well disposal. The Department's technical experts on wetlands permitting reside in DFWMR. Technical review of SPDES permits, including for industrial treatment plants, POTW's and injection wells is typically conducted by DOW. Other programs where DOW bears primary responsibility include stormwater permitting, dam safety permitting for freshwater impoundments, and review of headworks analysis to determine acceptability of a POTW's receiving flowback water. Waste haulers who transport wellsite fluids come under the purview of DSHM's Part 364 program, and must obtain a Beneficial Use Determination for road-spreading. DFWMR will review new proposed surface withdrawals to assist DMN in its determination of whether a site-specific SEQRA determination is required. DAR will have a primary permitting role if emissions at centralized flowback water surface impoundments or well pads trigger regulatory thresholds.

8.3 Well Permit Issuance

8.3.1 Use and Summary of Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

A generic environmental impact statement addresses common impacts and identified common mitigation measures. The proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing capture the mitigation measures identified as necessary by this review (see Appendix 10). These proposed conditions address all aspects of well pad activities, including:

- Planning and local coordination;
- Site preparation;
- Site maintenance;
- Drilling, stimulation (i.e., hydraulic fracturing) and flowback operations;
- Reclamation; and
- Other general aspects of the activity.

8.3.2 High-Volume Re-Fracturing

Because of the potential associated disturbance and impacts, the Department has determined that high-volume re-fracturing will require submission of the EAF Addendum and the Department's approval after:

- review of the planned fracturing procedures and products, water source, proposed site disturbance and layout, and fluid disposal plans;
- a site inspection by Department staff; and
- a determination of whether any other Department permits are required. If stormwater permit coverage has been terminated, then it must be re-attained prior to any site disturbance associated with high-volume re-fracturing.

Table 8.1
Regulatory Jurisdications Associated With High-Volume Hydraulic Fracturing

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

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

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

Contents

Chapter 9 ALTERNATIVE ACTIONS

Chapter 21 of the GEIS and the 1992 Findings Statement discussed a range of alternatives concerning oil and gas resource development in New York State that included both its prohibition and the removal of oil and gas industry regulation. Regulation as described by the GEIS was found to be the best alternative. Regulatory revisions recommended by the GEIS have been incorporated into permit conditions, which have been continuously improved since 1992.

The following range of alternatives to use of high volume hydraulic fracturing for Marcellus shale and other low permeability gas reservoirs have been reviewed for the purpose of this SGEIS:

- The prohibition of development of Marcellus Shale and other low permeability gas reservoirs by horizontal drilling and high-volume hydraulic fracturing.
- The use of a phased-permitting approach to developing the Marcellus Shale and other low permeability gas reservoirs, including consideration of limiting and/or restricting resource development in designated areas.
- The required use of green or non-chemical fracturing technologies and additives.

9.1 Prohibition of Development

The prohibition of development of Marcellus Shale and other low permeability gas reservoirs by horizontal drilling and high-volume hydraulic fracturing would be contrary to New York State and national interests. It would also contravene Article 23-0301 of the Environmental Conservation Law where it is stated:

> *It is hereby declared to be in the public interest to regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected, and to provide in similar fashion for the underground storage of gas, the solution mining of salt and geothermal, stratigraphic and brine disposal wells.*

As more fully described in Chapter 2, the Marcellus Shale formation, which extends from Ohio through West Virginia and into Pennsylvania and New York, is attracting attention as a significant new source of natural gas production. In New York, the Marcellus Shale is located in much of the Southern Tier, stretching from Chautauqua and Erie counties in the west to the counties of Sullivan, Ulster, Greene and Albany in the east. According to Penn State University, the Marcellus shale is the largest known shale deposit in the world. Engelder and Lash (2008) first estimated gas-in-place to be between 168 and 500 trillion cubic feet with a recoverable estimate of 50 tcf.[1] While it is very early in the productive life of Marcellus shale wells, the most recent estimates by Engelder (2009) using well production decline rates indicate a 50% probability that recoverable reserves could be as high as 489 trillion cubic feet.[2]

The Draft 2009 New York State Energy Plan recognizes the potential benefit to New York from development of the Marcellus Shale natural gas resource:

> Production and use of in-state energy resources – renewable resources and natural gas – can increase the reliability and security of our energy systems, reduce energy costs, and contribute to meeting climate change, public health and environmental objectives. Additionally, by focusing energy investments on in-state opportunities, New York can reduce the amount of dollars "exported" out of the State to pay for energy resources.[3]

[1] Considine et al., 2009, p. 2
[2] Considine et al., 2009, p. 2
[3] NYS Energy Planning Board, August 2009

The Draft Energy Plan further includes a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.[4]

The New York State Commission on Asset Maximization recommends that "Taking into account the significant environmental considerations, the State should study the potential for new private investment in extracting natural gas in the Marcellus Shale on State-owned lands, in addition to development on private lands." The Final report concludes that an increase in natural gas supplies would place downward pressure on natural gas prices, improve system reliability and result in lower energy costs for New Yorkers. In addition, natural gas extraction would create jobs and increase wealth to upstate landowners, and increase State revenue from taxes and land-owner leases and royalties. Development of State-owned lands could provide much needed revenue relief to the State and spur economic development and job creation in economically depressed regions of the State.[5]

Although total prohibition of natural gas development using high volume hydraulic fracturing of the Marcellus has been recommended by some, such a prohibition is contrary to New York statute and State policy advocating development of this resource. A prohibition would also deny owners of mineral interests an opportunity to realize the benefit of mineral rights ownership. It is not a reasonable alternative to development as set forth in this draft SGEIS.

9.2 Phased Permitting Approach

The use of a phased-permitting approach to developing the Marcellus Shale and other low permeability gas reservoirs, including consideration of limiting and restricting resource development in designated areas, was evaluated. Phased permitting as a means to mitigate regional cumulative impacts is not practical or necessary given the inherent difficulties in predicting gas well development for a particular region or part of the State. The mitigation proposed in the SGEIS that focuses on the siting of well pads based on Best Practices will lessen

[4] NYS Energy Planning Board, August 2009

[5] NYS Commission on Asset Maximization, June, 2009

or eliminate potential impacts. The 1992 GEIS found that the negative impacts associated with gas development were short term and could be mitigated with siting restrictions and setback requirements. This is also true for multi-well pads; therefore the mitigation techniques discussed in the 1992 GEIS and set forth in this SGEIS should be utilized.

Given the extended time period involved in fully developing a multi-well pad, control of the impacts, while still temporary, is essential. As stated in 1992, many of the potential negative impacts of gas development hinge on the location chosen for the well and the techniques used in constructing the access road and well site. Before a drilling permit can be issued, DEC staff must ensure that the proposed location of the well and access road complies with the Department's spacing regulations and siting restrictions. To assist in this process, DEC staff now has access to Policy Guidance Documents DEP-00-1, "Assessing and Mitigating Noise Impacts" and DEP-00-2, "Assessing and Mitigating Visual Impacts". If the guidance provided in these documents is applied where appropriate to multi-well pad applications along with a proposed site plan and design guidelines, it will be possible to avoid significant site-specific cumulative impacts. Additionally, the applicant should also be encouraged to review any applicable land use policy documents with the understanding that the New York State Department of Environmental Conservation (NYSDEC) retains authority to regulate gas development.[6]

The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource, rig, equipment and crew availability, permitting and oversight capacity, leasing, and most importantly economic factors. This holds true regardless of the type of drilling and stimulation utilized. Historically in New York, and in other plays, development has occurred in a sequential manner over years with development activity concentrated in one area then moving on with previously drilled sites fully or partially reclaimed as new sites are drilled. As with the development addressed in 1992, once drilling and stimulation activities are completed and the sites have been reclaimed, the long term impact will consist of widely spaced

---

[6] NTC, pp. 28-31

and partially re-vegetated production sites and fully reclaimed plugged and abandoned well sites.[7]

The statewide spacing regulations for vertical shale wells of one single well pad per 40-acre spacing unit will allow no greater density for horizontal drilling with high volume hydraulic fracturing than is allowed for conventional drilling techniques. This density was anticipated in 1992 and areas of New York, including Chautauqua, Cayuga and Seneca Counties, have experienced drilling at this level without significant negative impacts to agriculture, tourism, and other land uses.

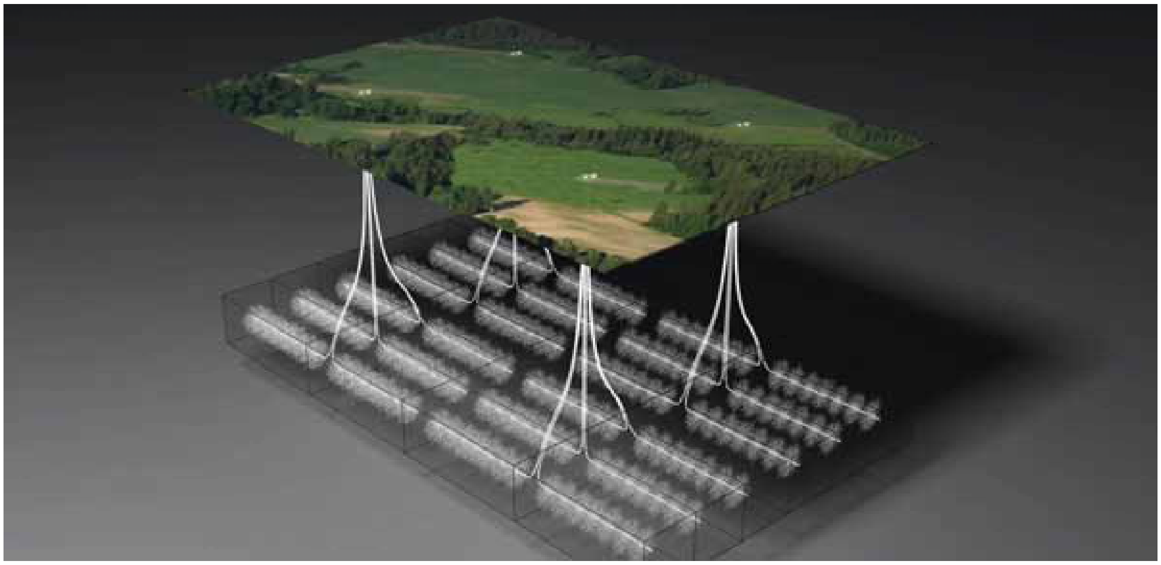
As discussed earlier, the density for multi-well pads, one per 640-acre spacing unit, is significantly less than for single well pads reducing the total number of disturbances to the landscape. While multi-well pads will be slightly larger than single well pads the reduction in number will lead to a substantial decrease in the total amount of disturbed acreage providing additional mitigation for long term visual and land use impacts on a regional basis. The following table provides an example for a 10 square mile area (i.e., 6,400 acres), completely drilled, comparing the 640 acre spacing option with multi-well pads and horizontal drilling to the 40 acre spacing option with single well pads and vertical drilling.

Spacing Option	**Multi-Well 640 Acre**	**Single Well 40 Acre**
Number of Pads	10	160
Total Disturbance - Drilling Phase	50 Acres (5 ac. per pad)	480 Acres (3 ac. per pad)
% Disturbance - Drilling Phase	.78	7.5
Total Disturbance - Production Phase	30 Acres (3 ac. per pad)	240 Acres (1.5 ac. per pad)
% Disturbance - Production Phase	.46	3.75

The reduction in sites should also allow for more resources to be devoted to proper siting and design of the pad to mitigating the short term impacts that result during the drilling and stimulation phase.[8] Some in industry have indicated that units much larger than 640 acres, possibly approaching 1280 acres, are being evaluated for future development from single, multi-

[7] NTC, pp. 28-31
[8] NTC, pp. 28-31

well pads. This would reduce the overall and regional gas well development footprint even further.



Source: Chesapeake Energy

9.2.1 Rate of Development and Thresholds

In response to questioning, a representative for one company estimated a peak activity for all of industry at 2,000 wells per year ± 25% in the New York Marcellus play. Other companies did not provide an estimate, listing the variables mentioned above as the reason. In Pennsylvania, where the Marcellus play covers a larger area and development has already occurred, the number of permits issued has increased in recent years as indicated in the following table. The source data provides information on the number of permits issued and is not indicative of the number of wells drilled.[9]

Year	Marcellus Permits Issued
2007	99
2008	510
2009 (Through 8/31)	1127

SOURCE: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG09.htm

[9] NTC, pp. 28-31

Recent development in the Barnett play in Texas, which utilizes the same horizontal drilling with high volume hydraulic fracturing that will be used in New York, has occurred at a rapid rate over the last decade. It is an approximately 4,000 square mile play located in and around the Dallas – Fort Worth area. In the eight year period from 2002 to 2008 approximately 10,500 wells were drilled.

The final scoping document summarizes the challenge of forecasting rates of development as follows:

"The number of wells which will ultimately be drilled cannot be known in advance, in large part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. Changes in the market and other economic conditions also have an impact on whether and how quickly individual wells are drilled."

Additional research has identified that "Experience developing shale gas plays in the past 20 years has demonstrated that every shale play is unique." Each individual play has been defined, tested and expanded based on understanding the resource distribution, natural fracture patterns, and limitations of the reservoir, and each play has required solutions to problems and issues required for commercial production. Many of these problems and solutions are unique to the play.[10]

"The timing, rate and pattern of development, on either a statewide or local basis, are very difficult to accurately predict." As detailed in Section 2.1.6 of the Final Scoping Document "overall site density is not likely to be greater than was experienced and envisioned when the GEIS and its Findings were finalized and certified in 1992."[11]

The rate of development cannot be predicted with any certainty based on the factors cited above and in the Final Scoping Document. Additionally, the threshold at which development results in adverse impacts to the topics studied in this report cannot be determined since it would be

[10] NTC, pp. 28-31
[11] NTC, pp. 28-31

subjective.[12] Research has not found any scientifically backed or measurable threshold that could be used for the topic areas discussed in this report. As a result, any limit to rate of development, or setting of thresholds, would be purely subjective and indefensible.[13]

9.2.2 Regional Cumulative Impacts Conclusion/Recommendation

The approach for addressing regional cumulative impacts is to focus on the proactive siting of well pads as discussed in previous sections of this SGEIS. If the location and construction of each well pad is based on 'Best Practices' (See Appendix A, NTC) then the potential impacts will be lessened and/or eliminated. When applications are reviewed, it is recommended that DEC examine any negative issues that have occurred on adjacent spacing units to determine if there is a potential problem in the area that needs further scrutiny.[14]

9.3 Green Or Non-Chemical Fracturing Technologies And Additives

Hydraulic fracturing operations involve the use of significant quantities of additives/products, albeit in low concentrations, which potentially could have an adverse impact on the environment if not properly controlled. The recognition of potential hazards has motivated investigation into environmentally-friendly alternatives for hydraulic fracturing technologies and chemical additives.[15]

It is important to note that use of 'environmentally friendly' or 'green' alternatives may reduce, but not entirely eliminate, adverse environmental impacts. Therefore, further research into each alternative is warranted to fully understand the potential environmental impacts and benefits of using any of the alternatives. In addition, the 'greenness' needs to be evaluated in a holistic manner, considering the full lifecycle impact of the technology or chemical.[16]

URS reports that the following environmentally-friendly technology alternatives have been identified as being in use in the Marcellus Shale, with other fracturing/stimulation applications or under investigation for possible use in Marcellus Shale operations:

---

[12] NTC, pp. 28-31
[13] NTC, pp. 28-31
[14] NTC, pp. 28-31
[15] URS, pp. 6-1 - 6-7
[16] URS, pp. 6-1 - 6-7

- Liquid carbon dioxide alternative – The use of a liquid carbon dioxide and proppant mixture reduces the use of other additives [19]. Carbon dioxide vaporizes leaving only the proppant in the fractures. The use of this technique in the US has been limited to demonstrations [20].

- Nitrogen-based foam alternative – Nitrogen-based foam fracturing was used in vertical shale wells in the Appalachian Basin until recently [21]. Nitrogen gas is unable to carry appreciable amounts of proppant and the nitrogen foam was found to introduce liquid components that can cause formation damage [22].

- Liquefied Petroleum Gas (LPG) – The use of LPG, consisting primarily of propane, has the advantages of carbon dioxide and nitrogen cited above; additionally, LPG is known to be a good carrier of proppant due to the higher viscosity of propane gel [55]. Further, mixing LPG with natural gas does not 'contaminate' natural gas; and the mixture may be separated at the gas plant and recycled [55]. LPG's high volatility, low weight, and high recovery potential make it a good fracturing agent. This technology is in limited use in Canada, and has not yet been used in the US.

- Horizontal and directional wells – These techniques are already in use in the Marcellus Shale. While these techniques require larger quantities of water and additives per well, horizontal and directional wells are considered to be more environmentally-friendly because these types of wells provide access to a larger volume of gas/oil than a typical vertical well [20, 23].[17]

The use of alternative chemical additives in hydraulic fracturing is another facet to the 'environmentally- friendly' development in recent years.

9.3.1 Environmentally-Friendly Chemical Alternatives

There are several US-based chemical suppliers who advertise 'green' hydraulic fracturing additives. For example, Earth-friendly GreenSlurry system from Schlumberger used in both the U.K. North Sea and the Gulf of Mexico [29]; Ecosurf EH surfactants by Dow Chemicals; or

[17] URS, pp. 6-1 - 6-7

'Green' Chemicals for the North Sea from BASF. USEPA has published the twelve principles of green chemistry and a sustainable chemistry hierarchy [30], yet these do not provide a common measure of environmental-friendliness to assess 'green' hydraulic fracturing additives.[18]

The 'environmentally-friendly' aspect of hydraulic fracturing of deep shale formations presently stem from drilling techniques, like horizontal drilling and mutli-well pads with smaller overall footprint, and from the use of environmentally-friendly chemicals.[19] Several US-based chemicals suppliers advertise 'green' chemicals, but there does not seem to be a US-based metric to evaluate the environmental-friendliness of these chemicals.[20] The most significant environmentally conscious hydraulic fracturing operations and regulations to date are likely in the North Sea. Several countries have established criteria that define environmental-friendliness, and utilize models and databases to track chemicals' overall hazardousness against those criteria. Similar to NYSDEC, the regulatory authorities in Europe request proprietary information from chemicals suppliers, and do not release any proprietary information into the public domain. The proprietary recipes for chemical additives are used to assess their potential hazard to the environment, and regulate their use as necessary. [21]

If applicable, New York could choose to adopt the criteria used in Europe, or New York might choose to adapt the European criteria, as appropriate, or the US might choose to set up an independent scientific entity to evaluate all chemicals proposed for use within US territories. However, at this time, it may not be feasible to require the use of 'green' chemicals because presently there is no metric or chemicals approvals process in place in the US. The evaluation of the 'greenness' of a chemical needs to consider the life-cycle impacts associated with that chemicals; and setting up a metric that provides a comprehensive evaluation is difficult. It is important to note that several products manufactured by US-based companies, and used or proposed for use in the Marcellus Shale in New York, may be found in the European approved chemicals lists.[22]

[18] URS, pp. 6-1 - 6-7
[19] URS, pp. 6-1 - 6-7
[20] URS, pp. 6-1 - 6-7
[21] URS, pp. 6-1 - 6-7
[22] URS, pp. 6-1 - 6-7

9.3.2 Summary

As the Marcellus Shale and other shale plays across the United States are developed, the development and use of ‘green chemicals’ will proceed based on the characteristics of each play and the potential environmental impacts of the development. While more research and approval criteria would be necessary for the requirement of ‘green chemicals,’ this SGEIS contains thresholds, permit conditions and review criteria to reduce or mitigate potential environmental impacts for development of the Marcellus Shale and other lowpermeability gas reservoirs using high volume hydraulic fracturing. These requirements may be altered as the use of ‘green chemicals’ begin to provide reasonable alternatives and the appropriate technology and processes are in place.

DEC

New York State Department of Environmental Conservation
Division of Mineral Resources

Glossary

for

Draft Supplemental Generic Environmental Impact Statement

Term	Definition
Access Road:	A road constructed to the wellsite that provides access for the drilling rig and other drilling-related equipment. The road is also used to inspect and maintain the well during the operating phase. Once a well is plugged and abandoned, the land the access road is on must be reclaimed, unless the landowner wants to keep the road.
Accumulator:	The storage device for nitrogen pressurized hydraulic fluid, which is used in operating the blowout preventers.
AERMOD:	American Meteorological Society's and USEPA's Regulatory Model recommended by EPA for regulatory dispersion modeling.
Agarwal-Gardner Type Curve Analysis:	See definition for "Decline or Type Curve Analysis"
Air Channel Test:	Air Channel Strength testing is a method of checking thermal welds joining PVC geomembrane liners together. This test method eliminates the need to cut holes in the liner to perform the tests.
ALJ:	Administrative Law Judge
Amphibolite:	A metamorphic rock consisting mainly of amphibole and plagioclase.
Anaerobic:	Living or active in the absence of free oxygen.
Anhydrite:	A mineral; anhydrous calcium sulfate, $CaSO4$
Anisotropy:	A crystal exhibiting properties with different values when measured in different directions.
Annular Flow:	A multiphase flow regime in which the lighter fluid flows in the center of the pipe, and the heavier fluid is contained in a thin film on the pipe wall. Annular flow occurs at high velocities of the lighter fluid, and is observed in both vertical and horizontal wells.
Annular Space or Annulus:	Space between casing and the wellbore, or between the tubing and casing or wellbore, or between two strings of casing
Anorthosite:	A plutonic rock (formed at great depth) composed almost wholly of plagioclase.
Anticline:	A fold with strata sloping downward on both sides from a common crest.
API:	American Petroleum Institute.
API Number:	A number referencing system designed by the American Petroleum Institute to identify wells; each state and county has a specific number code.
API:	American Petroleum Institute
Aquifer:	A zone of permeable, water saturated rock material below the surface of the earth capable of producing significant quantities of water.
Arps Decline Curve Analysis:	See definition for "Decline or Type Curve Analysis"
AST:	Above-ground Storage Tank
Attenuation:	The act of lessening the amount, force, magnitude, or value of.
Bactericides:	Also known as a "Biocide." An additive that kills bacteria. Bactericides are commonly used in water muds containing natural starches and gums that are especially vulnerable to bacterial attack. Bactericides can be used to control sulfate-reducing bacteria, slime-forming bacteria, iron-oxidizing bacteria, and bacteria that attack polymers in fracture and secondary recovery fluids.
Baker Tanks:	Portable skid-mounted storage tanks for temporary use at a wellsite.
Ballast:	The soil or stone material meant to hold down a geomembrane or geotextile material used in constructing a liner.
Bank Run Gravel:	Gravel found in natural deposits with varying mixtures of sand, silt and clay.

Barrel:	42 U.S. gallons.
Base Gas:	Also called "Cushion Gas." It's the gas needed to help produce the "working gas" rapidly. Base gas is normally held permanently within a gas storage reservoir.
BBL or bbl:	Abbr for a Barrel which is a measure of volume for petroleum products. One barrel is the equivalent of 42 U.S. gallons or 0.15899 cubic meters.
BCF or bcf:	Abbr for Billion cubic feet, which is a measure of natural gas.
Benching:	Method of quarrying by alternating vertical and horizontal excavations yielding a step (stair) profile.
Benthic:	Of or pertaining to the bottom of a standing body of water, including life forms inhabiting that area.
Bentonite:	A natural clay, used as a cement or mud additive for its expansive characteristics and/or its tendency to not separate from water.
Berm:	A narrow shelf, path, or ledge typically at the top or bottom of a slope. The term also applies to a mound or wall of earth or sand, as in a landscaped *berm*
Biocides:	See definition for "Bactericides"
Blasingame Type Curve Analysis:	See definition for "Decline or Type Curve Analysis"
Blending Unit or Blender:	The equipment used to prepare the slurries and gels commonly used in stimulation treatments. The blender should be capable of providing a supply of adequately mixed ingredients at the desired treatment rate. Modern blenders are computer controlled, which enables efficient control of quality and quantity.
Blooie Line:	Pipe that diverts fluids from the wellbore to a reserve pit.
Blowout:	Uncontrolled flow of gas, oil or water from a well.
BMP	Best Management Practices
BOD:	Biochemical (or biological) oxygen demand.
BOP:	Blowout Preventer.
Borehole:	See wellbore.
Brachiopod:	Any of the phylum of marine, shelled animals with two unequal shells (Brachiopoda).
Breaker:	A chemical used to reduce the viscosity of a fluid (break it down) after the thickened fluid has finished the job it was designed for.
Bridge Plug:	A type of mechanical packer that is usually permanent which is used in a well casing to isolate a zone.
Brine Disposal Well:	A well (Class IID) for subsurface injection of associated produced brines from oil, gas and underground gas storage operations, or a well (Class V) for disposal of spent brine from geothermal and solution mining operations.
Brine:	A solution containing appreciable amounts of NaCl and/or other salts. Synonymous with salt water.
Brush Bridge Plug:	An obstruction placed in a well at a specified depth. It can be the stump of a tree, brush, sacks, rags or any other material used as the foundation for a plug isolating a zone in the wellbore or casing.
Bryozoan:	Any of the phylum of aquatic invertebrate animals (Bryozoa).
BTX:	Benzene, Toluene, and Xylene. These are all aromatic hydrocarbons.
BTEX:	Benzene, Toluene, Ethylbenzene, and Xylene. These are all aromatic hydrocarbons
BUD:	Beneficial Use Determination issued by NYSDEC's Division of Solid and Hazardous Materials
Buffer Zone:	An area designed to protect and separate an activity from things around it.

Cable Tool:	Equipment (rig) for cable-tool drilling consisting of a heavy metal bar sharpened to a chisel-like point and attached to a cable. The gravity impact of the heavy metal bar (bit) pulverizes the rock which is removed with a bailer.
Caliper Log:	A log that is used to check for any wellbore irregularities. It is run prior to primary cementing as a means of calculating the amount of cement needed. Also run in conjunction with other open-hole logs for log corrections.
Cambrian Period:	Time period ranging from 580 to 520 million years ago.
Capillary Effect:	The phenomenon where water in small spaces, such as a thin tube or the small pore spaces in rock, moves forward by surface tension.
Carbonate:	Containing the $(CO_3)^{+2}$ radical.
Carcinogen:	Cancer causing substance.
CAS Number:	Chemicals Abstract Service number, assigned by Chemical Abstracts Service, which is part of the American Chemical Society. The CAS registry is the most authoritative collection of disclosed chemical substance information, containing more than 48 million organic and inorganic substances and 61 million sequences. Each CAS Registry Number (often referred to as a CAS Number) is a unique numeric identifier; higher or lower numbers have no chemical significance.
Casing:	Steel pipe placed in a well to prevent the wall of the hole from caving in, to isolate fresh water aquifers from the wellbore, to prevent movement of fluids from one formation to another, and to aid in well control.
Casinghead:	Top of surface casing above the ground to which control valves and flow pipes are attached.
Casing Shoe:	Reinforcing collar screwed onto the bottom of surface casing that guides the casing through the hole while absorbing the brunt of the shock.
Cation:	A positively charged ion.
Caustic:	A material that eats away (corrodes) by chemical action, high alkalinity. A base with a very high pH.
CBS:	Chemical Bulk Storage
CEA:	Critical Environmental Area.
Cement Bond Log:	A log used to evaluate the effectiveness of a primary cement job based on the different responses of sound waves in metal pipe and cement. It can also be used to locate channels in the cement.
Cement Retainer:	An expandable plug (packer) run on tubing or casing that allows cement to be pumped below.
Centipoise:	A unit of viscosity equal to one hundredth of a dyne-second per square centimeter.
Centrifuge:	An item of solids-removal equipment that removes fine and ultrafine solids. It consists of a conical drum that rotates at 2000 to 4000 rpm. Drilling fluid is fed into one end and the separated solids are moved up the bowl by a rotating scroll to exit at the other end. Centrifuges generally have limited processing capacity (50 to 250 gpm) but are useful for processing weighted drilling fluids and can remove finer solids than can a hydrocyclone or shaker screens. They can also be used for water clarification or for processing oily cuttings.
CFR:	Code of Federal Regulations
CH_4:	Methane
Chemical Tracer:	An identifiable substance, for example a dye, added to a system under study that can be detected at successive points in time to gather information about how the system/ process is working.

Choke:	A device with an orifice installed in a line to restrict the flow of fluids. Surface chokes are part of the Christmas tree (wellhead) on a well and contain a choke nipple, or bean, with a small-diameter bore that serves to restrict the flow. Chokes are also used to control the rate of flow of the drilling mud out of the hole when the well is closed in with the blowout preventer and a kick is being circulated out of the hole.
Choke Manifold:	The arrangement of piping and special valves, called chokes, through which drilling mud is circulated when the blowout preventers are closed to control the pressures encountered during a kick.
Circulation:	The round trip made by the well fluids from the surface down the tubing, wellbore or casing, and then back to the surface.
Class GSB Water:	The best usage of Class GSB waters is as a receiving water for disposal of wastes. Class GSB waters are saline groundwaters that have a chloride concentration in excess of 1,000 milligrams per liter or a total dissolved solids concentration in excess of 2,000 milligrams per liter.
Clastic:	Rock consisting of fragments of rocks that have been transported from other places.
Clay Stabilizer/Clay Inhibitor:	A chemical additive used in stimulation treatments to prevent the migration and/or swelling of clay particles. Without adequate protection, some water-base fluids can affect the electrical charge of clay particles and cause pieces of clay to swell and/or migrate in the flowing fluid where they may plug the target formation and lower production.
$CO_{2:}$	Carbon Dioxide
CO_2e:	Carbon Dioxide equivalents
Coagulate:	To cause or become thickened or clotted.
COGCC:	Colorado Oil and Gas Conservation Commission
Completion:	Preparation of a well for production after it has been drilled.
Compressive Strength:	Measure of the ability of a substance to withstand compression.
Compressor Stations:	A device that raises the pressure of a compressible fluid, such as air or gas. Compressors create a pressure differential to move or compress a vapor or a gas.
Compulsory Integration:	New York's Environmental Conservation Law (Article 23, Titles 5 and 9 as amended by Chapter 386 of the Laws of 2005) gives all property owners the opportunity to recover or receive the gas beneath their property. To protect these "correlative rights," the Department of Environmental Conservation may establish spacing units whenever necessary. Compulsory integration is required when any owner in a spacing unit does not voluntarily integrate their interests with those of the unit operator. Compensation to the compulsory integrated interests will be established by a DEC Commissioner's Order after a public hearing.
Condensate:	Liquid hydrocarbons recovered by conventional surface separators from natural gas. Condensate has an API gravity of 50° to 120°.
Conductor Hole:	The hole for conductor pipe or casing.
Conductor Pipe or Casing:	This large diameter casing is usually the first string of casing in a well. It is set or driven into the unconsolidated material where the well will be drilled to keep the loose material from caving in. It is usually relatively short in length.
Conglomeritic:	Rock containing notceable chunks of smaller rock materials.
Connate Water:	Water trapped in the pore space of sedimentary rocks at the time the rock was deposited.
Constituents:	Parts of a whole
Consumptive Uses:	Water withdrawn for a variety of personal, agricultural or industrial purposes.

Correlative Rights:	Rights of any mineral owner to recover resources that underlay their property.
Corrosion Inhibitor:	A chemical substance that minimizes or prevents corrosion in metal equipment.
Crosslinkers:	A compound, typically a metallic salt, mixed with a base-gel fluid, such as a guar-gel system, to create a viscous gel used in some stimulation or pipeline cleaning treatments. The crosslinker reacts with the multiple-strand polymer to couple the molecules, creating a fluid of high viscosity.
Cumulative Impact:	Two or more individual effects on the environment which, when taken together, may compound or increase the other's environmental impact.
Cushion Gas:	See definition for "Base Gas."
Cuttings or Samples:	Chips of rock cut by the drill bit and brought to the surface by the drilling fluid. They indicate to the wellsite workers what kind of rocks are being penetrated and can also indicate the presence of oil or gas.
CWA	Clean Water Act
CZM:	Coastal Zone Management.
DAR:	Division of Air Resources within the NYS Department of Environmental Conservation
DAR-1 (Air Guide-1)	Division of Air Resources program policy guidelines for the control of toxic air contaminants
Darcy:	A unit of permeability equal to one cubic centimeter of fluid of one centipoise viscosity flowing in one second under a pressure differential of one atmosphere through a porous medium having a cross section of one square centimeter and a length of one centimeter.
DEC:	New York State Department of Environmental Conservation
Decline or Type Curve Analysis:	A decline curve analysis is a method to fit observed production information from a well or wells to a mathematical function that forms a curve and to use this information to predict future production. **Arps** introduced the decline curve analysis using mathematical functions in the 1940s. In the early 1980s **Fetkvoich** introduced a new kind of decline curve analysis based on type curves. It is essentially a graphical technique for visual matching of production data using pre-plotted curves on log-log paper. In 1993 **Blasingame** and Palacio introduced improvements to address the issue of variable bottom-hole pressures in gas wells. In 1999 **Agarwal et al**. introduced new type curves that made further refinements allowing the user to clearly distinguish between transient and boundary-dominated flow periods. Aside from all the refinements, the essential function of these analytical techniques remains the same - to examine historic production from a well or wells and predict future production.
Decollement:	A subhorizontal zone of detachment between two lithologic (rock) layers.
Deflocculants:	A thinning agent used to reduce viscosity or prevent flocculation; incorrectly called a "dispersant." Most deflocculants are low-molecular weight anionic polymers that neutralize positive charges on clay edges. Examples include polyphosphates, lignosulfonates, quebracho and various water-soluble synthetic polymers.
Dehydrator:	A device used to remove water and water vapors from gas.
Deliverability:	Volume per unit of time that can be delivered.
De-silter:	A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid. This keeps the amount of solids in the fluid to the lowest possible level.

De-sander:	A centrifugal device for removing sand from drilling fluid to prevent abrasion of the pumps. It may be operated mechanically or by a fast-moving stream of fluid inside a special cone-shaped vessel, in which case it is sometimes called a hydrocyclone.
Detritus:	Fine particulate organic debris.
Devonian Period:	Period of geologic time which ranges from 415 to 360 million years ago.
Dip:	Angle of inclination from the horizontal.
Dipole Sonic Log:	A type of acoustic log that displays traveltime of P-waves versus depth.
Dipper:	A localized, somewhat archaic term for a person who salvages floating oil from surface waters.
Disconformity:	A surface of erosion between parallel rock strata or a point of contact between two discordant structures (e.g., a dike).
Disposal Well:	A well into which waste fluids can be injected deep underground for safe disposal. Disposal wells are subject to regulatory requirements to prevent contamination of aquifers.
DMN:	Division of Mineral Resources in the NYS Department of Environmental Conservation.
DMR:	Division of Marine Resources in the NYS Department of Environmental Conservation.
Doghouse	A small enclosure on the rig floor used as an office and/or as a storehouse for small objects. Also, any small building used as an office or for storage.
DOH:	(New York State) Department of Health
Dolostone:	A sedimentary rock composed of fragmental, concretionary, or precipitated dolomite [CaMg(CO3)2].
Dome:	A roughly symmetrical upward convex fold.
Double Hot Wedge Seam:	A thermal welding technique that works by melting the two geomembrane surfaces being joined.
DOW:	Division of Water in the NYS Department of Environmental Conservation
DMV:	(New York State) Department of Motor Vehicles
DPS:	(New York State) Department of Public Service
DRA:	Division of Regulatory Affairs in the NYS Department of Environmental Conservation.
DRBC	Delaware River Basin Commission
Drag Fold:	Minor folding of strata along the walls of a fault in which the “drag” of displacement has produced flexures in the beds on either side.
Drilling Fluid:	Mud, water, or air pumped down the drill string which acts as a lubricant for the bit and is used to carry rock cuttings back up the wellbore. It is also used for pressure control in the wellbore.
Drive Pipe:	See definition for "Conductor Casing"
Dry Hole:	Any well that does not produce oil or gas in commercial quantities. A dry hole may flow water, gas, or even oil, but not in amounts large enough to justify production.
DSHM:	Division of Solid and Hazardous Materials in the NYS Department of Environmental Conservation
E & P:	Exploration and Production
EAF:	Environmental Assessment Form.
ECL:	Environmental Conservation Law
Ecosystem:	The system composed of interacting organisms and their environments.

EDR:	Electrodialysis Reversal
Effective Porosity:	Property of rock or soil containing intercommunicating pore space, expressed as a percent volume of total bulk volume.
Effluent:	Something that flows out, in particular a waste material such as an industrial discharge.
EIS:	Environmental Impact Statement
Electrical Leak Location:	This is a type of quality assurance test that uses electrical resistivity to locate any defects that might be present in a geomembrane.
EM&CP:	Environmental Management and Construction Plan
EM&CS&P:	Environmental Management and Construction Standards and Practices
Eminent Domain:	A right of government to take private property for public use.
Entrainment:	The condition of being drawn into something and transported with it, for example, gas bubbles in cement.
E&P:	Exploration and Production
EPA:	(U.S.) Environmental Protection Agency
EPCRA:	Emergency Planning and Community Right to Know Act of 1986
Evaporite:	Sediment deposited from ancient seas as a result of extensive or total evaporation.
Exploratory Well:	A well drilled outside a proven productive area or horizon.
FAA:	(U.S.) Federal Aviation Administration
Falloff Test:	The measurement and analysis of pressure data taken after an injection well is shut in.
Fault:	A fracture or fracture zone along which there has been displacement of the sides relative to each other.
Fetkovich Decline Curve Analysis:	See definition for "Decline or Type Curve Analysis"
Field:	The area encompassing a group of producing oil and/or gas wells.
Filter Cloth:	Material used to underlay fill and other material which allows water to pass through it, but not sediment, thus preventing settling and unwanted siltation.
Flare:	The burning of unwanted gas through a pipe (also called a flare). Flaring is a means of disposal used when there is no way to transport the gas to market and the operator cannot use the gas for another purpose. Flaring generally is not allowed because of the high value of gas and environmental concerns
Flocculant:	A chemical added to a fluid to cause unwanted particles, such as clay, to clump together for easier removal.
Floodplain:	Level land built up by stream deposition (past floods) that may be subject to future flooding.
Flowback:	Return of fluids, used in the stimulation process, to the surface.
Flowmeter:	An instrument that measures fluid flow rates.
Flue Gas:	An exhaust gas coming out of a pipe or stack.
Fluid Saturation:	Percent volume of effective porosity occupied by a fluid.
FMCSA:	Federal Motor Carrier Safety Administration
Foaming Agents:	An additive used to make foam in a drilling fluid. Drilling foam is water containing air or gas bubbles, much like shaving foam, and it must withstand high salinity, hard water, solids, entrained oil, and high temperature. Foaming agents are usually nonionic surfactants and contain polymeric materials.
Fold:	A bend in rock strata.

Footwall:	The mass of rock beneath a fault plane.
Formation matrix:	A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.
Fossils:	The remains or traces of plants or animals which have been preserved by natural causes.
Fracing (pronounced “fracking”):	See the definition for "Hydraulic Fracturing"
Freeboard:	The height above the recorded high-water mark of a structure associated with the water. In the case of pits, the extra depth left unused to prevent any
Friction Reducers:	An additive, generally in slurry or liquid form, used to reduce the friction forces experienced by tools and tubulars in the wellbore. Friction reducers are routinely used in horizontal and highly deviated wellbores where the friction forces limit the passage of tools along the wellbore.
Fry:	Recently hatched fish.
Gamma Ray Log:	Log that records natural gamma radiation of the formations. Shales can be identified because of their high natural gamma radiation content.
Gas Cap Drive:	Type of primary reservoir energy where free, compressed gas exists above an accumulation of saturated oil and exerts pressure on the oil causing it to move toward the wellbore.
Gas Saturation:	Percent of effective porosity occupied by gas.
Gas-Water Separator:	A device used to separate undesirable water from gas produced from a well.
GEIS:	Generic Environmental Impact Statement
Gelling Agents:	Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.
Geocomposite Drainage System:	This refers to a geosynthetic (man-made) drainage system meant to perform the same drainage function as soil or stone. They are carefully designed to have a specific transmissivity tailored to the project.
Geomembrane:	Man-made polymeric membrane (flexible membrane) that is manufactured to be essentially impermeable and is used to build containment pits.
Geosynthetic Clay Liner:	A layer of processed clay bonded or fixed between two sheets of geotextile.
Geothermal Gradient:	The rate at which the earth’s temperature increases with depth. The general average is 1°F/100'.
Geothermal Well:	A well drilled to explore for or produce natural heat found in underground hydrothermal, geopressured, or hot dry rock reservoirs.
GHG:	Greenhouse gas
GPD:	Gallons per day
GRI:	Gas Research Institute
Gravity Drive:	A type of primary reservoir energy where the force of gravity is sufficient to cause oil and gas to flow to the wellbore.
Graywacke:	A coarse sandstone or fine-grained conglomerate, usually dark gray, composed of subangular to rounded fragments of quartz, feldspars, etc.
Grenville Province:	Eastern margin of the vast Canadian Shield. It includes the Precambrian rocks exposed in the Adirondack Mountains
Groundwater:	Water in the subsurface below the water table. Groundwater is held in the pores of rocks, and can be connate, from meteoric sources, or associated with igneous intrusions.
Grout:	A concrete mixture that can be placed into a well annulus from the surface. Also a verb.
GWP:	Global warming potential

GWPC:	Ground Water Protection Council
Hanging Wall:	Mass of rock above a fault plane.
HAPS:	Hazardous Air Pollutants as defined under the Clean Air Act
Hardpan:	A hard impervious layer of soil composed chiefly of clay cemented by relatively insoluble materials.
HDPE:	High-density polyethylene. This plastic is resistant to most chemicals, insoluble in organic solvents, and has high impact and tensile strength.
Henry's Law Constant:	Ratio of a chemical's vapor pressure in the atmosphere to its solubility in water.
Heterogeneity:	Formation with rock properties changing with location in the reservoir. Some naturally fractured reservoirs are heterogeneous formations.
HMTA:	Hazardous Material Transportation Act
HMTUSA:	Hazardous Materials Transportation Uniform Safety Act
Horizontal Drilling:	Deviation of the borehole from vertical so that the borehole penetrates a productive formation in a manner parallel to the formation.
Horizontal Leg:	The part of the wellbore that deviates significantly from the vertical; it may or may not be exactly horizontal.
Hydraulic Fracturing:	Injection of fluids under pressure into a well in order to induce fractures in the target formation. Proppant injected with the fluid holds the fractures open when the fluid is withdrawn. The procedure increases permeability of the rock near the wellbore and improves production.
Hydrocarbons:	Organic compounds of hydrogen and carbon whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds, because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solids. Petroleum is a mixture of many different hydrocarbons.
Hydrogen Sulfide or H_2S:	A malodorous, toxic gas with the characteristic odor of rotten eggs.
Hypalon:	Commercial name for a synthetic plastic-like material used to line pits.
ICF:	ICF International, a consulting firm
Idle Well:	A well which is unplugged and that has been inactive longer than two years.
Igneous Rocks:	Rock formed by solidification from a molten or partially molten state.
Indigenous:	Having originated in and being produced, growing, living, or occurring naturally in a particular region or environment.
Inert Chemical:	Lacking a usual or anticipated chemical or biological action.
Inert Gas:	Group of gases that exhibit great stability and extremely low reaction rates.
Infill Drilling:	Drilling between known producing wells to better exploit the reservoir.
Infill Wells	Wells drilled between known producing wells to better exploit the reservoir.
Infrastructure:	The system of public works of a country, state, or region. It can also refer to the resources (as personnel, buildings, or equipment) required for an activity.
Injectate:	Injectate is any substance injected down a well.
Injection Well:	A well through which fluids are injected into an underground stratum to increase reservoir pressure and to displace oil. Also called an input well.
Injection Zone:	A geological formation, group of formations, or part of a formation that receives fluids through a well.

Intermediate Casing or String:	Casing set below the surface casing in deep holes where added support or control of the wellbore is needed. It goes between the surface casing and the conductor casing. In very deep wells, more than one string of intermediate casing may be used.
Interstitial:	Relating to, or situated in, the interstices, spaces or cracks between things.
IOGA:	Independent Oil and Gas Association
Iron Inhibitors:	Chemicals used to bind the metal ions and prevent a number of different types of problems that the metal can cause (for example, scaling problems in pipe).
IOGCC:	Interstate Oil and Gas Compact Commission
Joule-Thompson Effect:	Referring to the change in temperature observed when a gas expands while flowing through a restriction without any heat entering or leaving the system. The change may be positive or negative. The Joule-Thomson effect often causes a temperature decrease as gas flows through pores of a reservoir to the wellbore.
Kill Fluid:	A heavy fluid which exerts a hydrostatic pressure equal to the bottomhole pressure (pressure at bottom of well). It is put into a well to get the well back under control if there has been a kick or a blowout.
Landlocked:	Enclosed or nearly enclosed by land.
Lanyards:	Broadly; a chord or line to hold something.
Leakoff:	The magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. This term is normally associated with a test to determine the strength of the rock, commonly called a pressure integrity test (PIT) or a leakoff test (LOT).
Lease Gas:	Gaseous hydrocarbons produced at the well or on the lease.
Lifelines:	Broadly; a line to which a person may cling, attach, or use to save or protect their life.
Limestone:	A bedded sedimentary deposit consisting chiefly of calcium carbonate ($CaCO_3$).
Lingula:	An ancient genus of brachiopods (shelled marine animals).
Lithologic:	Referring to the physical charateristics of rocks or sediment that can be determined with the human eye.
Log:	A systematic recording of data, such as a driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells to discern various characteristics of rock formations that the wellbore passes through.
Lost Circulation:	The quantities of drilling fluid lost to a formation, usually in cavernous, pressured, or coarsely permeable beds. Evidenced by the complete or partial failure of the mud to return to the surface as it is being circulated in the hole.
Lost Circulation Material:	Material put into fluids to block off the permeability of a lost circulation zone.
Lost Circulation Zone:	Rock formation that is so permeable or soluble that it diverts the flow of fluids from the well.
LPG:	Liquified Petroleum Gas
LWRP:	Local Waterfront Revitalization Program.
Macaroni String:	Small diameter tubing used for cleaning out or cementing into confined spaces such as the well tubing or annulus.
Manifold:	An arrangement of piping or valves designed to control, distribute and often monitor fluid flow. Manifolds are often configured for specific functions, such as a choke manifold used in well-control operations and a squeeze manifold used in squeeze-cementing work. In each case, the functional requirements of the operation have been addressed in the configuration of the manifold and the degree of control and instrumentation required.

Marine:	Of, belonging to, or caused by the sea.
Marker Bed:	A bed which is distinctive and traceable in outcrop or which accounts for a characteristic signature on a geophysical log or seismic time-distance curve.
MCF or Mcf:	Thousand cubic feet.
MCL or MCLG	Maximum Contaminant Level (Goal)
Metamorphism:	Chemical and/or physical change in a rock as a result of heat and/or pressure.
Methane:	Methane (CH_4) is a greenhouse gas that remains in the atmosphere for approximately 9-15 years. Methane is also a primary constituent of natural gas and an important energy source.
Microseismic mapping:	Data are acquired by monitoring perforating jobs, string-shot tests, or other seismic sources in the treatment well or in another nearby well in order to determine the actual dimensions of the fracture and where it is located.
Microseisms (or microseismic events):	Small bursts of seismic energy generated by shear slippages along planes of weakness in the reservoir and surrounding layers which are induced by changes in stress and pore pressure around the hydraulic fracture. These microseisms are extremely small, and sensitive receiver systems are required. Microseisms do not map out exactly where individual hydraulic fracture planes are located, but rather form an ellipsoid around the fracture, outlining the length, height, and azimuth of the fracture.
Micro-annulus (plural is micro-annuli):	A small gap that can form between the casing or liner and the surrounding cement sheath, most commonly formed by variations in temperature or pressure during or after the cementing process. Such variations cause small movement of the steel casing, breaking the cement bond and creating a microannulus that is typically partial. However, in severe cases the microannulus may encircle the entire casing circumference. A microannulus can jeopardize the hydraulic efficiency of a primary cementing operation, allowing communication between zones if it is severe and connected.
mg/l:	milligrams per liter
Mineral Rights:	The ownership of the minerals under a given surface, with the right to enter and remove them. It may be separated from the surface ownership.
MMCF or MMcf:	Million cubic feet.
Mousehole:	A short hole drilled to the side of a wellbore to hold the next joint of drill pipe.
MSDS:	Material Safety Data Sheet
MSGP:	Multi-Sector General Permit
Mudboils:	Silty mounds formed under certain very unusual geologic conditions as groundwater erupts at the surface.
Mudlogging (Unit):	Trailer located at the wellsite housing equipment and personnel to progressively analyze wellbore cuttings washed up from the borehole. A portion of the mud is diverted through a gas-detecting device.
NAAQS and AAQS:	National or State Ambient Air Quality Standards for criteria pollutants
Native Gas:	Gas originally in place in an underground formation. Term is usually associated with gas storage.
NGPA:	Natural Gas Policy Act of 1978.
NOI:	Notice of Intent
Noise Log:	A log that picks up sound vibrations in the wellbore caused by flowing liquid or gas. Used to determine fluid entry points or flow behind casing.

Non-Darcy Flow:	Fluid flow that deviates from Darcy's law, which assumes laminar flow in the formation. Non-Darcy flow is typically observed in high-rate gas wells when the flow converging to the wellbore reaches flow velocities exceeding the Reynolds number for laminar or Darcy flow, and results in turbulent flow. Since most of the turbulent flow takes place near the wellbore in producing formations, the effect of non-Darcy flow is a rate-dependent skin effect.
Nonwetting Phase:	The pore space fluid which is not attached to the reservoir rock and thus has the greatest mobility.
N20:	Nitrous Oxide
$NO_{2:}$	Nitrogen Dioxide
NORM – Naturally Occurring Radioactive Materials	Low-level radioactivity that can exist naturally in native materials, like some shales and may be present in drill cuttings and other wastes from a well. Oil and gas production and processing operations sometimes cause NORM to accumulate at elevated concentrations in by-product waste streams. The primary radionuclides of concern are isotopes of radium that originate from the decay of uranium and thorium naturally present in the subsurface formations from which oil and gas are produced. The production wastes most likely to be contaminated by elevated radium include produced water, scale, and sludge.
Normalized Pressure Integral Curve Analysis:	This is another type of Decline or Type Curve Analysis. See that definition.
NPDES:	National Pollution Discharge Elimination System
NWS:	National Weather Service
NYCDEP:	New York City Department of Environmental Protection
NYCRR:	New York Codes of Rules and Regulations
NYSDOH	New York State Department of Health
NYSDOT:	New York State Department of Transportation.
NYSERDA:	New York State Energy Research and Development Authority
Offset Well:	An existing wellbore close to a proposed well that provides information for planning the proposed well. In planning development wells, there are usually numerous offsets, so a great deal is known about the subsurface geology and pressure regimes. In contrast, rank wildcats have no close offsets, and planning is based on interpretations of seismic data, distant offsets and prior experience. High-quality offset data are coveted by competent well planners to optimize well designs. When lacking offset data, the well planner must be more conservative in designing wells and include more contingencies.
Oil Wet:	The condition in the pore space of the rock where oil coats the grains of the rock and is the more immobile phase.
Operator:	Any person or organization in charge of the development of a lease or drilling and operation of a producing well.
OPRHP:	(NY State) Office of Parks, Recreation and Historic Preservation.
Ordovician Period:	Period of geologic time ranging from 520 to 465 million years ago.
Overburden:	Material of any type that overlies the rock deposit of interest and must be removed before the desirable product can be excavated.
Paleozoic Era:	A period of geologic time ranging from 570 to 225 million years ago, the beginning of which is marked by the appearance of abundant fossils.
Parameter	A characteristic of a model of a reservoir that may or may not vary with respect to position or with time. Porosity is a petrophysical parameter (or characteristic) that varies with position.

Passby Flow Requirement	A prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring. Passby requirements also specify low- flow conditions during which no water can be withdrawn
Pathogens:	A specific causative agent (as a virus or bacterium).
Pay:	Zone of oil or gas in commercial quantities.
PBS	Petroleum Bulk Storage
Pennsylvanian Epoch:	Period of geologic time ranging from 310 to 280 million years ago.
Percolation Test:	Test to determine at what rate fluids will pass through soil.
Perforate:	To make holes through the casing to allow the oil or gas to flow into the well or to squeeze cement behind the casing.
Permeability:	1. a measure of the ease with which a fluid flows through the connecting pore spaces of a formation or cement. The unit of measurement is the millidarcy. 2. fluid conductivity of a porous medium. 3. ability of a fluid to flow within the interconnected pore network of a porous medium.
Permeable:	Having pores or openings that allow liquids to pass through.
Petroleum:	In the broadest sense the term embraces the full spectrum of hydrocarbons (gaseous, liquid, and solid).
PHMSA	Pipeline and Hazardous Materials Safety Administration
PID:	Perforation Inflow Diagnostic
Piezometer:	A nonpumping well, generally of small diameter, for measuring the elevation of a water table.
Pipe Racks	Horizontal supports for storing tubular goods.
Plat:	A map of land plots; a drafted map of the site location.
Plug Back	To place cement in or near the bottom of a well to exclude bottom water, to sidetrack, or to produce from a formation higher in the well. Plugging back can also be accomplished with a mechanical plug set by wireline, tubing, or drill pipe.
Plugged and Abandoned	(plug and abandon) To place cement plugs into a dry hole and abandon it.
Plugged and Abandoned	(plug and abandon) To prepare a well to be closed permanently, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir.
Plugging:	To place cement and other fluids in a well at appropriate intervals in order to prevent migration of fluids from or within the well.
Pluton:	A body of igneous rock that has formed beneath the surface of the earth.
PM10 and PM2.5	Particulate matter with sizes of less than 10 and 2.5 microns, respectively.
Pneumatic:	Run by or using compressed air.
Poisson's ratio	An elastic constant that is a measure of the compressibility of material perpendicular to applied stress, or the ratio of latitudinal to longitudinal strain. This elastic constant is named for Simeon Poisson (1781 to 1840), a French mathematician.
Polymer:	Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.
Polymerization:	A chemical reaction in which two or more molecules combine to form larger molecules that contain repeating structural units.

Pool:	An underground reservoir or trap containing oil and/or gas. Pool is also the term for a single separate reservoir with its own pressure system.
Porosity:	Volume of pore space expressed as a percent of the total bulk volume of the rock.
Potable:	Suitable for drinking by humans.
POTW:	Publicly Owned Treatment Works
ppm:	parts per million
Precambrian Era:	A period of time ranging from 4,500 to 570 million years ago.
Pressure Buildup Test:	An analysis of data obtained from measurements of the bottomhole pressure in a well that is shut-in after a flow period. The profile created on a plot of pressure against time is used with mathematical reservoir models to assess the extent and characteristics of the reservoir and the near-wellbore area.
Primary Aquifer	In order to enhance regulatory protection in areas where groundwater resources are most productive and most vulnerable, the NYS Department of Health, in 1980, identified eighteen Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the state. These are defined in the Division of Water Technical & Operational Guidance Series (TOGS) 2.1.3 as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems".
Primary Production:	Production of a reservoir by natural energy in the reservoir.
Primary Reservoir Energy:	The naturally occurring condition or mechanism which exists in a reservoir that aids the migrations of fluids to the wellbore.
Principal Aquifer:	The NYS Department of Health, in 1980, identified a category of groundwater resources listed in TOGS 2.1.3 as Principal Aquifers. These are "aquifers known to be highly productive or whose geology suggests abundant potential water supply, but which are not intensively used as sources of water supply by major municipal systems at the present time".
Production Casing:	Casing set above or through the producing zone through which the well produces.
Production Water:	Water produced from oil and gas wells.
Proppant or Propping Agent:	A granular substance (sand grains, aluminum pellets, or other material) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.
PSC:	Public Service Commission.
PSD:	Prevention of Significant Deterioration defined in the Clean Air Act
PSI:	Pounds per square inch.
PSIG:	Pounds per Square Inch Gauge
PSL:	Public Service Law
Pump and Plug Method:	A technique for placing cement plugs at appropriate intervals.
PVC:	Polyvinylchloride; a durable petroleum derived plastic.
Quartz:	A mineral, SiO_2.
Radioactive Tracer:	A component of a production-logging tool that carries a radioactive solution (often carnotite) that can be selectively released into a flow stream. When the radioactive solution is released into an injected fluid, the movement of the mixture can be traced by gamma ray detectors located in the tool.

Radioactive Tracer Surveys (RATS):	A survey in which a radioactive isotope is released in a well and followed with a detector which is used to detect fluid movement and rate. It can also be used to recognize channels behind casing, tubing or casing leaks, and determine the flow direction of injected fluids.
Rat-hole:	A short slanted hole drilled near the wellbore to hold the kelly joint when not in use.
Real Property:	Includes mineral claims, surface and water rights.
REC	Reduced Emissions Completion
Reclaimed	(Reclamation) Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, re-vegetation, and other work necessary to restore it.
Reeving:	Hoisting from the derrick floor to the crown block.
Reserve pit:	A mud pit in which a supply of drilling fluid has been stored. Also, a waste pit, usually an excavated, earthen-walled pit. It may be lined with plastic to prevent soil contamination.
Reservoir	A subsurface, porous, permeable or naturally fractured rock body in which oil or gas are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The four basic types of hydrocarbon reservoirs are oil, volatile oil, dry gas, and gas condensate. An oil reservoir generally contains three fluids—gas, oil, and water—with oil the dominant product. In the typical oil reservoir, these fluids become vertically segregated because of their different densities. Gas, the lightest, occupies the upper part of the reservoir rocks; water, the lower part; and oil, the intermediate section. In addition to its occurrence as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. Volatile oil reservoirs are exceptional in that during early production they are mostly productive of light oil plus gas, but, as depletion occurs, production can become almost totally completely gas. Volatile oils are usually good candidates for pressure maintenance, which can result in increased reserves. In the typical dry gas reservoir natural gas exists only as a gas and production is only gas plus fresh
Reservoir Rock:	A permeable rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.
Reworked:	Sediment that has been moved after preliminary deposition, commonly resulting in transportation and sorting.
Rework	To restore production from an existing formation when it has fallen off substantially or ceased altogether.
Riprap:	Erosion control device. Heavy irregular rocks or concrete used to form a wall or foundation that must resist the forces of waves, tides, or strong currents.
RO:	Reverse Osmosis
Rollovers:	Convex upward folds on the hanging wall of a thrust fault.
Rotary Rig:	A derrick equipped with rotary equipment where a well is drilled using rotational movement.
Royalties:	The landowner's share of the value of oil and gas produced.
Run-Off:	The portion of precipitation on land that ultimately reaches streams sometimes with dissolved or suspended material.
Sacrificial Anode:	Cathodic protection provided by galvanic coupling of an anode (a substance which easily loses electrons or corrodes) to a well casing, tank or pipeline needing protection. The sacrificial anode is consumed during protection of the steel object.
Sandstone:	A variously colored sedimentary rock composed chiefly of sandlike quartz grains cemented by lime, silica or other materials.

Scale Inhibitor:	A chemical substance which prevents the accumulation of a mineral deposit (for example, calcium carbonate) that precipitates out of water and adheres to the inside of pipes, heaters, and other equipment.
Schist Arenite:	Metamorphosed graywacke.
Scolithus:	Trace fossil, vertical tube left by a burrowing organism.
Secondary Recovery:	The extraction of oil from a field beyond what can be recovered by normal methods of flowing or pumping.
Secondary Silica Cement:	Silica (SiO_2) precipitated in the pore space of a rock after deposition.
Sedimentary:	Rocks formed from sediment transported from their source and deposited in water.
Sedimentation Control	(sedimentation) The process of separation of the components of a cement slurry during which the solids settle. Sedimentation is one of the characterizations used to define slurry stability.
Seep:	Natural leakage of gas or oil at the earth's surface.
Seismic:	Related to earth vibrations produced naturally or artificially.
Separator:	Tank used to physically separate the oil, gas, and water produced simultaneously from a well.
SEQR:	Reference to the regulatory program or type of review done under SEQRA.
SEQRA:	State Environmental Quality Review Act.
Sequestering Agent:	A chemical additive that reduces chemical reactions.
Setback:	Minimum distance required between a well operation and other zones, boundaries, or objects such as highways, wetlands, streams, or houses.
Scrim:	This is a filament used as reinforcement in geomembrane.
SGC/AGC:	Short-term Guideline Concentration and Annual Guideline Concentrations defined in DAR-1 (Air Guide 1) procedures.
SGEIS:	Supplemental Generic Environmental Impact Statement
Shale:	Laminated sedimentary rock in which the constituent particles are predominantly of clay size.
Shale Shaker:	A series of trays with sieves or screens that vibrate to remove cuttings from circulating fluid in rotary drilling operations. The size of the openings in the sieve is selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. Also called a shaker.
Shear Wave (S-wave):	Elastic body wave in which particles oscillate perpendicular to the direction in which the wave propogates. S-waves, or shear waves, travel more slowly than P-waves and cannot travel through fluids. Interpretation of S-waves can help determine rock properties
Short Ton:	20 short hundred weight, 2,000 pounds.
Show:	Small quantity of oil or gas, not enough for commercial production.
Shut In (Verb):	To close the valves at the wellhead to keep the well from flowing or to stop producing a well.
Shut-In (Adjective):	The state of a well which has been shut-in.
Significant Habitats:	Areas which provide one or more of the key factors required for survival, variety or abundance of wildlife, and/or for human recreation associated with such wildlife.
Siliceous:	Of, relating to, or derived from silica.
Sill:	Sill is the term for a submerged horizontal ridge embedded in stream bottom usually at relatively shallow depth. It can also be intruded body of igneous rock that is parallel to bedding.
SILs:	Significant Impact Levels for criteria pollutants

Siltation:	The build-up of silt in a stream or lake as a result of activity that disturbs the streambed, bank, or surrounding land.
Siltstone:	Sediment in which the constituent particles are predominantly silt size.
Silurian Period:	Period of time ranging from 405 to 415 million years ago.
Skin Effects:	The loss in amplitude and change in phase of an electromagnetic field as it penetrates into a conductive medium. In an induction log, the skin effect causes a reduction of the R-signal (in-phase) and an increase in the X-signal (out-of-phase) at the receiver. It has a significant effect on the 6FF40 array, particularly below 1 ohm-m. Since the magnitude of the reduction depends on the conductivity, the skin effect can be corrected for by using a fixed function of the measured conductivity. A much improved method is to estimate the correction from the X-signal measured in balanced arrays. 2. [Well Testing] An increase or decrease in the pressure drop predicted with Darcy's law using the value of permeability thickness, kh, determined from a buildup or drawdown test. The difference is assumed to be caused by the "skin." Skin effect can be either positive or negative. The skin effect is termed positive if there is an increase in pressure drop, and negative when there is a decrease, as compared with the predicted Darcy pressure drop. A positive skin effect indicates extra flow resistance near the wellbore, and a negative skin effect indicates flow enhancement near the wellbore. The terms skin effect and skin factor are
Slick-Water Fracturing:	Water combined with a friction-reducing chemical additive which allows the water to be pumped faster into the formation. Water fracs don't use any polymers to thicken and the amount of proppant used is significantly less than that of gels. Slick water fracs work very well in low-permeability reservoirs, and they have been the primary instrument that has opened up unconventional plays like the Texas Barnett Shale. In addition to the cost advantage, water fracs require less cleanup and provide longer fractures. In shale formations, brine water is used because the salt content inhibits the formation from swelling. Freshwater is used in other formations where swelling of the clays is not a problem.
Sliding Scale:	A flexible scale that can be adjusted to variables (e.g., income, time).
Slippage:	The phenomenon in multiphase flow when one phase flows faster than another phase, in other words slips past it. Because of this phenomenon, there is a difference between the holdups and cuts of the phases.
Sloughing:	Cave-in of soil or soft rock such as shales from the side of the wellbore.
SO_2:	Sulfur Dioxide
Solution Gas Drive:	Type of primary reservoir energy where the major mechanism of energy is a result of gas coming out of solution with decreased reservoir pressure.
Sonic Log:	See "Dipole Sonic Log"
Source Bed:	Rocks in which oil or gas are generated.
Spacing Unit:	An area allotted to a well by regulations or field rules issued by a governmental authority having jurisdiction for the drilling and production of a well.
Spacing:	Distance separating wells in a field to optimize recovery of oil and gas.
SPDES:	State Pollutant Discharge Elimination System.
Spinner Survey:	Generic name for logs that use spinner type velocimeters to monitor fluid velocities. Used to identify leaks in casing or tubing, to analyze stimulation results, and to establish injection or production profiles and flow rates.
Spring:	A place where groundwater naturally flows from a rock or soil onto land or into a body of surface water.
Spudding:	The breaking of the earth’s surface in the initial stage of drilling a well.

Squeeze:	Technique where cement is forced under pressure into the annular space between casing and the wellbore, between two strings of pipe, or into the casing-hole annulus.
SRBC	Susquehanna River Basin Commission
Standpipe:	A vertical pipe rising along the side of the derrick or mast. It joins the discharge line leading from the mud pump to the rotary hose and through which mud is pumped going into the hole.
Step Out:	To move the minimum spacing unit outside an existing area.
Step-Rate Pressure Test:	Pressure test where a succession of equal pressure steps (usually increasing) are sustained for a constant time duration.
Stimulation:	The act of increasing a well's productivity by artificial means such as hydraulic fracturing, acidizing, shooting, etc.
Strand Plain:	The shoreline, a beach.
Stratigraphic Test Well:	A hole drilled to gather engineering, geologic or hydrological information including but not limited to lithology, structural, porosity, permeability and geophysical data.
Stratigraphic Trap:	Accumulation of hydrocarbons entrapped as a result of variation in rock type, usually caused by a change in the environment of deposition.
Stratigraphy:	The study of the history, composition, relative ages and distribution of strata, and the interpretation of strata to elucidate Earth history.
Stratum (plural strata):	Layers of sedimentary rock that form beds.
Stream's Designated Best Use:	Each waterbody in NYS has been assigned a classification, which reflects the designated "best uses" of the waterbody. These best uses typically include the ability to support fish and aquatic wildlife, recreational uses (fishing, boating) and, for some waters, public bathing, drinking water use or shellfishing. Water quality is considered to be good if the waters support their best uses.
Strippers:	Wells producing less than 10 (BOPD) barrels of oil per day or 60 thousand cubic feet of gas per day.
Stromatolite:	Laminated calcareous rocks formed from fossil algae.
Structural Trap:	Accumulation of hydrocarbons entrapped as a result of faulting or folding.
Substructure	A vertical pipe rising along the side of the derrick or mast. It joins the discharge line leading from the mud pump to the rotary hose and through which mud is pumped going into the hole.
Surface Casing:	Casing extending from the surface to below the deepest fresh water aquifer. It is inside the conductor pipe and also acts as an anchor for well control equipment.
Surface Impoundment:	A liquid containment facility that can be installed in a natural topographical depression, excavation, or bermed area formed primarily of earthen materials, then lined with a geomembrane or or a combination of other geosynthetic materials.
Surface Rights:	Ownership of the surface of land only with no right to the mineral resources underneath.
Surfactants:	Chemical additives that reduce surface tension; or a surface active substance. Detergent is a surfactant.
Swab:	To clean out the borehole of a well with a special tool on a wireline which evacuates fluids and reduces the hydrostatic head to encourage flow.
SWPPP:	Stormwater Pollution Prevention Plan
Synclinorium:	A broad regional syncline on which minor folds are superimposed.

Taconic Orogeny:	Mountain building episode in the latter part of the Ordovician Period, named for the Taconic Range of eastern New York.
Tag:	To check the presence and location of something, usually in reference to cement plugs in a wellbore. Plugs may be tagged using the drill stem, tubing string or other equipment.
Tank Battery:	A group of tanks used for storage of oil and other produced fluids from a well or wells.
Target Formation	The formation that the driller is trying to reach when drilling the well.
TD:	Total depth
TDS:	Total Dissolved Solids.
TDS:	The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.
TENORM:	Technologically Enhanced Naturally Occurring Radioactive Material. The radioactive wastes from extraction and processing are sometimes called 'Technologically Enhanced Naturally Occurring Radioactive Material' (TENORM) because human activity has concentrated the radioactivity or increased the likelihood of exposure by making the radioactive material more accessible to human contact.
Tensile Strength:	The force per unit cross-sectional area required to pull a substance apart.
Thrust Fault:	A low angle reverse fault; the hanging wall moves up in relation to the foot wall.
Tight Formation:	Formation with very low permeabilities.
Tile Drainage:	Man-made drainage system utilizing open-ended ceramic pipes in areas of poor drainage.
TMD	Total measured depth.
Total Kjeldahl Nitrogen	The sum of organic nitrogen; ammonium NH3 and ammonia NH4+ in water and soil analyses
Tote:	Tote tanks are generally small (1,100 gallons or less) and owned by the product supplier. The supplier fills a tank with a product and delivers the filled tank to the facility or user. The facility places the tote tank near the area where it will be needed and may move the tank to supply more than one piece of equipment. When the tote tank is empty, the supplier replaces the empty tank rather than refilling it on site. The same tank does not stay at a given facility for any longer than it takes to use the product in the tank. It may take anywhere from a few days to a few months to use the product in the tank.
Transfer Coefficient:	Overall amount of mass transfer of a chemical from a liquid container to the atmosphere.
Trap:	A body of porous and permeable, hydrocarbon bearing rock which is sealed by impervious rock. 2. A geologic structure which retards the free migration of hydrocarbons.
TVD:	Total vertical depth.
Turbidity:	Amount of suspended solids in a liquid.
UIC – Underground Injection Control:	A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.
UN:	United Nations
Unit Operation:	Joint operation of separately owned producing leases in a field, pool or reservoir.
USCG:	United States Coast Guard

USDOT:	United States Department of Transportation
USDW – Underground Source of Drinking Water	An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer.
USEPA:	United States Environmental Protection Agency
Viscosity:	A measure of the degree to which a fluid resists flow under an applied force.
Vitrinite Reflectance:	A measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an effective source rock. The reflectivity of at least 30 individual grains of vitrinite from a rock sample is measured under a microscope. The measurement is given in units of reflectance, % R_o, with typical values ranging from 0% R_o to 3% R_o. Strictly speaking, the plant material that forms vitrinite did not occur prior to Ordovician time, although geochemists have established a scale of equivalent vitrinite reflectance for rocks older than Ordovician.
VMT:	Vehicle Miles Traveled
VOC:	Voaltile Organic Compounds
Water Drive:	Type of primary reservoir energy where the energy is provided by the influx of water from the sides, edge, or below the oil accumulation.
Watershed:	Drainage area of a stream, lake, or aquifer.
Water-wet:	The condition in the pore space of a rock where water coats the grains of the rock and is the more immobile phase.
Weathered:	Endured the action of the atmosphere.
Well Location Plat:	A plan, map, or chart of a piece of land with actual or proposed features (as lots) ; *also* **:** the land represented.
Well Pad:	A temporary drilling site, usually constructed of local materials such as sand and gravel. After the drilling operation is over, most of the pad is usually removed or plowed back into the ground. As required by DEC the land must be graded properly, mulched and seeded to reclaim the land.
Wellbore:	A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open. Also called a borehole or hole.
Wellhead:	The equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casinghead and tubing head. adj: pertaining to the wellhead.
Wildcat:	Well drilled in area where oil and gas has not yet been found
Wireline:	A general term used to describe well-intervention operations conducted using single-strand or multistrand wire or cable for intervention in oil or gas wells. Although applied inconsistently, the term commonly is used in association with electric logging and cables incorporating electrical conductors.
Wireline gamma-logging:	A continuous measurement of formation properties with electrically powered instruments to infer properties and make decisions about drilling and production operations. The record of the measurements, typically a long strip of paper, is also called a log.
WOC Time:	"Waiting on cement" time. Pertaining to the time when drilling or completion operations are suspended so that the cement in a well can harden sufficiently.
Working Gas:	In regard to underground gas storage, gas recovered from storage for sale to customers.
Workover:	Repair operations on a producing well to restore or increase production

WRCRA:	Waterfront Revitalization and Coastal Resources Act
Young's Modulus:	An elastic constant named after British physicist Thomas Young (1773 to 1829) that is the ratio of longitudinal stress to longitudinal strain and is symbolized by E.
Zonal Isolation:	Zonal isolation means there are barriers preventing material of any type from leaving or entering the zone. In the case of a well, zones downhole are isolated by approporate use of casing, cement, plugs and packers.
Zone:	A slab of reservoir rock bounded above and below by impermeable rock.

New York State

DEC

Division of Mineral Resources

Appendices

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

New York State Department of Environmental Conservation

Table of Appendices

New York State

DEC

Division of Mineral Resources

Appendix 1

FEMA
Flood Insurance Rate Map
Availability

Excerpted from Alpha Environmental, 2009

Draft Supplemental Generic Environmental Impact Statement

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Albany	Albany, City of	4/15/1980
Albany	Altamont, Village of	8/15/1983
Albany	Berne,Town of	8/1/1987 (L)
Albany	Bethlehem, Town of	4/17/1984
Albany	Coeymans, Town of	8/3/1989
Albany	Cohoes, City of	12/4/1979
Albany	Colonie, Town of	9/5/1979
Albany	Green Island, Village of	6/4/1980
Albany	Guilderland, Town of	1/6/1983
Albany	Knox, Township of	8/13/1982 (M)
Albany	Menands, Village of	3/18/1980
Albany	New Scotland, Town of	12/1/1982
Albany	Ravena, Village of	4/2/1982 (M)
Albany	Rensselaerville, Town of	8/27/1982 (M)
Albany	Voorheesville, Village of	12/1/1982
Albany	Watervliet, City of	1/2/1980
Albany	Westerlo, Town of	8/3/1989
Allegany	Alfred, Town of	10/7/1983 (M)
Allegany	Alfred, Village of	2/15/1980
Allegany	Allen, Town of	7/16/1982 (M)
Allegany	Alma, Town of	10/7/1983 (M)
Allegany	Almond, Village of	2/15/1980
Allegany	Amity, Town of	12/18/1984
Allegany	Andover, Town of	3/2/1998
Allegany	Andover, Village of	4/2/1979
Allegany	Angelica, Town of	12/31/1982 (M)
Allegany	Angelica, Village of	2/1/1984
Allegany	Belfast, Town of	8/6/1982 (M)
Allegany	Belmont, Village of	12/18/1984
Allegany	Birdsall, Town of	7/16/1982 (M)
Allegany	Bolivar, Town of	7/30/1982 (M)
Allegany	Bolivar, Village of	1/19/1996
Allegany	Burns, Town of	7/16/1982 (M)
Allegany	Canaseraga, Village of	12/2/1983 (M)
Allegany	Caneadea, Town of	8/20/1982 (M)
Allegany	Clarksville, Town of	11/12/1982 (M)
Allegany	Cuba, Town of	7/30/1982 (M)
Allegany	Cuba, Village of	4/17/1978
Allegany	Friendship, Town of	12/18/1984
Allegany	Genesee, Town of	7/30/1982 (M)
Allegany	Granger, Town of	10/7/1983 (M)
Allegany	Grove, Town of	11/6/1991
Allegany	Hume, Town of	10/2/1997
Allegany	Independence, Town of	7/9/1982 (M)
Allegany	New Hudson, Town of	8/20/1982 (M)
Allegany	Richburg, Village of	1/5/1978
Allegany	Rushford, Town of	12/23/1983 (M)
Allegany	Scio, Town of	3/18/1985
Allegany	Ward,Town of	(NSFHA)
Allegany	Wellsville, Town of	3/18/1985
Allegany	Wellsville, Village of	7/17/1978

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Allegany	West Almond, Town of	(NSFHA)
Allegany	Willing, Town of	12/24/1982 (M)
Allegany	Wirt, Town of	6/25/1982 (M)
Broome	Barker, Town of	2/5/1992
Broome	Binghamton, City of	6/1/1977
Broome	Binghamton, Town of	1/6/1984 (M)
Broome	Chenango, Town of	8/17/1981
Broome	Colesville, Town of	1/20/1993
Broome	Conklin, Town of	7/17/1981
Broome	Dickinson, Town of	4/15/1977
Broome	Endicott, Village of	9/7/1998
Broome	Fenton, Town of	8/3/1981
Broome	Johnson City, Village of	9/30/1977
Broome	Kirkwood, Town of	6/1/1977
Broome	Lisle, Town of	8/20/2002
Broome	Lisle, Village of	1/6/1984 (M)
Broome	Maine, Town of	2/5/1992
Broome	Nanticoke, Town of	12/18/1985
Broome	Port Dickinson, Village of	5/2/1977
Broome	Sanford, Town of	6/4/1980
Broome	Triangle, Town of	7/20/1984 (M)
Broome	Union, Town of	9/30/1988
Broome	Vestal, Town of	3/2/1998
Broome	Whitney Point, Village of	1/6/1984 (M)
Broome	Windsor, Town of	9/30/1992
Broome	Windsor, Village of	5/18/1992
Cattaraugus	Allegany, Town of	11/15/1978
Cattaraugus	Allegany, Village of	12/17/1991
Cattaragus	Ashford, Township of	5/25/1984
Cattaraugus	Carrollton, Town of	3/18/1983 (M)
Cattaraugus	Cattaraugus, Village of	4/20/1984 (M)
Cattaraugus	Cold Spring, Town of	3/1/1978
Cattaraugus	Conewango, Town of	7/30/1982 (M)
Cattaraugus	Dayton, Town of	5/25/1984 (M)
Cattaraugus	Delevan, Village of	1/20/1984 (M)
Cattaraugus	East Otto, Town of	4/20/1984 (M)
Cattaraugus	East Randolph, Village of	2/1/1978
Cattaraugus	Ellicottville, Town of	1/19/2000
Cattaraugus	Ellicottville, Village of	5/2/1994
Cattaraugus	Farmersville, Town of	7/23/1982 (M)
Cattaraugus	Franklinville, Town of	7/17/1978
Cattaraugus	Franklinville, Village of	7/3/1978
Cattaraugus	Freedom, Town of	8/19/1991
Cattaraugus	Great Valley, Town of	7/17/1978
Cattaraugus	Hinsdale, Town of	1/17/1979
Cattaraugus	Humphrey, Town of	8/13/1982 (M)
Cattaraugus	Ischua, Town of	8/15/1978
Cattaraugus	Leon, Town of	8/13/1982 (M)
Cattaraugus	Limestone, Village of	4/17/1978
Cattaraugus	Little Valley, Town of	6/22/1984 (M)
Cattaraugus	Little Valley, Village of	2/1/1978

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Cattaraugus	Lyndon, Town of	7/16/1982 (M)
Cattaraugus	Machias, Town of	8/20/1982 (M)
Cattaraugus	Mansfield, Town of	5/25/1984 (M)
Cattaraugus	Napoli, Town of	7/2/1982 (M)
Cattaraugus	New Albion, Town of	12/3/1982 (M)
Cattaraugus	Olean, City of	5/9/1980
Cattaraugus	Olean, Town of	2/1/1979
Cattaraugus	Otto, Town of	4/20/1984 (M)
Cattaraugus	Perrysburg, Town of	4/20/1984 (M)
Cattaraugus	Persia, Town of	4/20/1984 (M)
Cattaraugus	Portville, Town of	7/18/1983
Cattaraugus	Portville, Village of	4/17/1978
Cattaraugus	Randolph, Town of	11/5/1982 (M)
Cattaraugus	Randolph, Village of	8/1/1978
Cattaraugus	Salamanca, City of	4/17/1978
Cattaraugus	Salamanca, Town of	11/1/1979
Cattaraugus	South Dayton, Village of	1/5/1978
Cattaraugus	South Valley, Town of	12/2/1983 (M)
Cattaraugus	Yorkshire, Town of	5/25/1984 (M)
Cattaraugus/Erie/ Chautauqua/Allegany	Seneca Nation of Indians	9/30/1988
Cayuga	Auburn, City of	8/2/2007
Cayuga	Aurelius, Town of	8/2/2007
Cayuga	Aurora, Village of	8/2/2007
Cayuga	Brutus, Town of	8/2/2007
Cayuga	Cato, Town of	8/2/2007
Cayuga	Cato, Village of	8/2/2007
Cayuga	Cayuga, Village of	8/2/2007
Cayuga	Conquest, Town of	8/2/2007
Cayuga	Fair Haven, Village of	8/2/2007
Cayuga	Fleming, Town of	8/2/2007
Cayuga	Genoa,Town of	8/2/2007
Cayuga	Ira, Town of	8/2/2007
Cayuga	Ledyard, Town of	8/2/2007
Cayuga	Locke, Town of	8/2/2007
Cayuga	Mentz, Town of	8/2/2007
Cayuga	Meridian, Village of	8/2/2007
Cayuga	Montezuma, Town of	8/2/2007
Cayuga	Moravia, Town of	8/2/2007
Cayuga	Moravia, Village of	8/2/2007
Cayuga	Niles, Town of	8/2/2007
Cayuga	Owasco, Town of	8/2/2007
Cayuga	Port Byron, Village of	8/2/2007
Cayuga	Scipio, Town of	8/2/2007
Cayuga	Sempronius, Town of	8/2/2007
Cayuga	Sennett, Town of	8/2/2007
Cayuga	Springport, Town of	8/2/2007
Cayuga	Sterling, Town of	8/2/2007
Cayuga	Summer Hill, Town of	8/2/2007
Cayuga	Throop, Town of	8/2/2007
Cayuga	Union Springs, Village of	8/2/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Cayuga	Venice, Town of	8/2/2007
Cayuga	Victory, Town of	8/2/2007
Cayuga	Weedsport, Village of	8/2/2007
Chautauqua	Arkwright, Town of	4/8/1983 (M)
Chautauqua	Bemus Point, Village of	11/2/1977
Chautauqua	Brocton, Village of	(NSFHA)
Chautauqua	Busti, Town of	1/20/1993
Chautauqua	Carroll, Town of	10/29/1982 (M)
Chautauqua	Cassadaga, Village of	12/1/1977
Chautauqua	Celoron, Village of	3/18/1980
Chautauqua	Charlotte, Town of	3/23/1984 (M)
Chautauqua	Chautauqua, Town of	6/15/1984
Chautauqua	Cherry Creek, Town of	7/2/1982 (M)
Chautauqua	Cherry Creek, Village of	2/15/1978
Chautauqua	Clymer, Town of	10/7/1983 (M)
Chautauqua	Dunkirk, City of	2/4/1981
Chautauqua	Dunkirk, Town of	8/6/1982 (M)
Chautauqua	Ellery, Town of	3/18/1980
Chautauqua	Ellicott, Town of	8/1/1984
Chautauqua	Ellington, Town of	10/7/1983 (M)
Chautauqua	Falconer, Village of	1/5/1978
Chautauqua	Forestville, Village of	3/18/1983 (M)
Chautauqua	Fredonia, Village of	11/15/1989
Chautauqua	French Creek, Town of	6/8/1984 (M)
Chautauqua	Gerry, Town of	1/6/1984 (M)
Chautauqua	Hanover, Town of	12/18/1984
Chautauqua	Harmony, Township of	12/1/1986 (L)
Chautauqua	Jamestown, City of	6/1/1978
Chautauqua	Kiantone, Town of	2/2/1996
Chautauqua	Lakewood, Village of	11/2/1977
Chautauqua	Mayville, Village of	1/5/1978
Chautauqua	Mina, Town of	1/2/2003
Chautauqua	North Harmony, Town of	2/15/1980
Chautauqua	Panama, Village of	3/1/1978
Chautauqua	Poland, Town of	3/11/1983 (M)
Chautauqua	Pomfret, Town of	12/18/1984
Chautauqua	Portland, Town of	10/7/1983 (M)
Chautauqua	Ripley,Town of	(NSFHA)
Chautauqua	Sheridan, Town of	10/7/1983 (M)
Chautauqua	Sherman, Village of	3/1/1978
Chautauqua	Sherman,Town of	1/6/1984 (M)
Chautauqua	Silver Creek, Village of	8/1/1983
Chautauqua	Sinclairville, Village of	12/1/1977
Chautauqua	Stockton, Town of	10/21/1983 (M)
Chautauqua	Villenova, Town of	5/21/1982 (M)
Chautauqua	Westfield, Town of	6/8/1984 (M)
Chautauqua	Westfield, Village of	10/7/1983 (M)
Chemung	Ashland, Town of	1/16/1980
Chemung	Baldwin, Town of	7/23/1982 (M)
Chemung	Big Flats, Town of	8/18/1992
Chemung	Catlin, Town of	6/22/1984 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Chemung	Chemung, Town of	9/3/1980
Chemung	Elmira Heights, Village of	9/29/1996
Chemung	Elmira, City of	4/2/1997
Chemung	Elmira, Town of	9/29/1996
Chemung	Erin, Town of	8/13/1982 (M)
Chemung	Horseheads, Town of	9/29/1996
Chemung	Horseheads, Village of	9/29/1996
Chemung	Millport, Village of	6/15/1988 (M)
Chemung	Southport, Town of	8/5/1991
Chemung	Van Etten, Town of	9/28/1979 (M)
Chemung	Van Etten, Village of	7/1/1988 (L)
Chemung	Veteran, Town of	2/18/1983 (M)
Chemung	Wellsburg, Village of	6/15/1981
Chenango	Afton, Town of	9/30/1992
Chenango	Afton, Village of	9/30/1992
Chenango	Bainbridge, Town of	12/3/1991
Chenango	Bainbridge, Village of	6/2/1993
Chenango	Columbus, Town of	4/8/1983 (M)
Chenango	Coventry, Town of	10/15/1985 (M)
Chenango	Earlville, Village of	6/5/1985 (S)
Chenango	German, Town of	9/24/1984 (M)
Chenango	Greene, Town of	8/3/1981
Chenango	Greene, Village of	8/3/1981
Chenango	Guilford, Town of	7/6/1984 (M)
Chenango	Lincklaen, Town of	3/23/1984 (M)
Chenango	Mc Donough, Town of	6/5/1985 (M)
Chenango	New Berlin, Town of	6/5/1985 (M)
Chenango	New Berlin, Village of	11/4/1983 (M)
Chenango	North Norwich, Town of	12/3/1991
Chenango	Norwich, City of	12/18/1985
Chenango	Norwich, Town of	11/15/1984
Chenango	Otselic, Town of	6/5/1985 (M)
Chenango	Oxford, Town of	8/24/1984 (M)
Chenango	Oxford, Village of	9/10/1984 (M)
Chenango	Pharsalia, Town of	8/24/1984 (S)
Chenango	Pitcher, Town of	3/4/1986 (M)
Chenango	Plymouth, Town of	11/4/1983 (M)
Chenango	Preston, Town of	4/1/1983 (M)
Chenango	Sherburne, Town of	8/24/1984 (M)
Chenango	Sherburne, Village of	9/10/1984 (M)
Chenango	Smithville, Town of	11/4/1983 (M)
Chenango	Smyrna, Town of	9/24/1984 (M)
Chenango	Smyrna, Village of	10/15/1985 (M)
Clinton	Altona, Town of	9/28/2007 (M)
Clinton	Ausable, Town of	9/28/2007 (M)
Clinton	Beekmantown, Town of	9/28/2007
Clinton	Black Brook, Town of	9/28/2007
Clinton	Champlain, Town of	9/28/2007
Clinton	Champlain, Village of	9/28/2007
Clinton	Chazy, Town of	9/28/2007
Clinton	Clinton, Town of	9/28/2007 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Clinton	Ellenburg, Town of	9/28/2007 (M)
Clinton	Mooers, Town of	9/28/2007 (M)
Clinton	Peru,Town of	9/28/2007
Clinton	Plattsburgh, City of	9/28/2007
Clinton	Plattsburgh, Town of	9/28/2007
Clinton	Rouses Point, Village of	9/28/2007
Clinton	Saranac, Town of	9/28/2007
Clinton	Schuyler Falls, Town of	9/28/2007
Columbia	Ancram, Town of	6/5/1985 (M)
Columbia	Austerlitz, Town of	6/5/1985 (M)
Columbia	Canaan, Town of	7/3/1985 (M)
Columbia	Chatham, Town of	9/15/1993
Columbia	Chatham, Village of	12/15/1982
Columbia	Claverack, Town of	9/6/1989
Columbia	Clermont, Township of	9/5/1984
Columbia	Copake, Town of	6/19/1985 (M)
Columbia	Gallatin, Town of	10/16/1984
Columbia	Germantown, Town of	5/11/1979 (M)
Columbia	Ghent, Town of	1/1/1988 (L)
Columbia	Greenport, Town of	11/15/1989
Columbia	Hillsdale, Town of	5/15/1985 (M)
Columbia	Hudson, City of	9/29/1989
Columbia	Kinderhook, Town of	12/1/1982
Columbia	Kinderhook, Village of	12/1/1982
Columbia	Livingston, Town of	5/11/1979 (M)
Columbia	New Lebanon, Town of	6/5/1985 (M)
Columbia	Stockport, Town of	1/19/1983
Columbia	Stuyvesant, Town of	9/14/1979 (M)
Columbia	Taghkanic, Town of	1/3/1986 (M)
Columbia	Valatie, Village of	12/1/1982
Cortland	Cincinnatus, Town of	5/15/1985 (M)
Cortland	Cortland, City of	8/15/1983
Cortland	Cortlandville, Town of	8/15/1983
Cortland	Cuyler, Town of	5/15/1985
Cortland	Freetown, Town of	1/17/1975
Cortland	Harford, Town of	5/15/1985 (M)
Cortland	Homer, Town of	8/15/1983
Cortland	Homer, Village of	8/15/1983
Cortland	Lapeer, Town of	7/20/1984 (M)
Cortland	Marathon, Town of	5/15/1985 (S)
Cortland	Marathon, Village of	10/15/1982
Cortland	Mcgraw, Village of	12/1/1982
Cortland	Preble, Town of	5/15/1985 (M)
Cortland	Scott, Town of	5/15/1985 (M)
Cortland	Solon, Town of	5/15/1985
Cortland	Taylor, Town of	5/15/1985 (M)
Cortland	Truxton, Town of	5/15/1985 (M)
Cortland	Virgil, Town of	5/15/1985 (M)
Cortland	Willet, Town of	7/20/1984 (M)
Delaware	Andes, Town of	5/1/1985 (M)
Delaware	Andes, Village of	4/1/1986 (L)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Delaware	Bovina, Town of	5/1/1985 (M)
Delaware	Colchester,Town of	2/4/1987
Delaware	Davenport, Town of	2/2/2002
Delaware	Delhi, Town of	7/18/1985
Delaware	Delhi, Village of	7/18/1985
Delaware	Deposit, Town of	3/18/1986 (M)
Delaware	Fleischmanns, Village of	1/17/1986 (M)
Delaware	Franklin, Town of	4/1/1988 (L)
Delaware	Franklin, Village of	8/1/1987 (L)
Delaware	Hamden,Town of	3/4/1986 (M)
Delaware	Hancock, Town of	9/28/1990
Delaware	Hancock, Village of	9/28/1990
Delaware	Harpersfield, Town of	6/5/1985 (M)
Delaware	Hobart, Village of	5/15/1985 (M)
Delaware	Kortright, Town of	5/15/1985 (M)
Delaware	Margaretville, Village of	6/4/1990
Delaware	Masonville, Town of	11/1/1985 (M)
Delaware	Meredith, Town of	5/15/1985 (M)
Delaware	Middletown, Town of	8/2/1993
Delaware	Roxbury, Town of	5/15/1985 (M)
Delaware	Sidney, Town of	9/30/1987
Delaware	Sidney, Village of	9/30/1987
Delaware	Stamford, Town of	10/1/1986 (L)
Delaware	Stamford, Village of	8/1/1987 (L)
Delaware	Tompkins, Town of	11/15/1985 (M)
Delaware	Walton, Town of	9/2/1988
Delaware	Walton, Village of	4/2/1991
Delaware/Broome	Deposit, Village of	2/1/1979
Dutchess	Amenia, Town of	11/15/1989
Dutchess	Beacon, City of	3/1/1984
Dutchess	Beekman, Town of	9/5/1984
Dutchess	Clinton, Town of	7/5/1984
Dutchess	Dover, Town of	7/4/1988
Dutchess	East Fishkill, Town of	6/15/1984
Dutchess	Fishkill, Town of	6/1/1984
Dutchess	Fishkill, Village of	3/15/1984
Dutchess	Hyde Park, Town of	6/15/1984
Dutchess	Lagrange, Town of	9/8/1999
Dutchess	Milan, Town of	8/10/1979 (M)
Dutchess	Millbrook, Village of	2/27/1984 (M)
Dutchess	Millerton, Village of	1/3/1985
Dutchess	North East, Town of	9/5/1984
Dutchess	Pawling, Town of	1/3/1985
Dutchess	Pawling, Village of	8/1/1984
Dutchess	Pine Plains, Town of	10/5/1984 (M)
Dutchess	Pleasant Valley, Town of	1/16/1980
Dutchess	Poughkeepsie, City of	1/5/1984
Dutchess	Poughkeepsie, Town of	9/8/1999
Dutchess	Red Hook, Town of	10/16/1984
Dutchess	Red Hook, Village of	(NSFHA)
Dutchess	Rhinebeck, Town of	9/5/1984

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Dutchess	Rhinebeck, Village of	2/1/1985
Dutchess	Stanford, Town of	12/17/1991
Dutchess	Tivoli, Village of	8/1/1984
Dutchess	Union Vale, Town of	9/2/1988
Dutchess	Wappinger, Town of	9/22/1999
Dutchess	Wappingers Falls, Village of	9/22/1999
Dutchess	Washington, Town of	8/17/1979 (M)
Erie	Akron, Village of	11/19/1980
Erie	Alden, Town of	2/6/1991
Erie	Alden, Village of	1/6/1984 (M)
Erie	Amherst, Town of	10/16/1992
Erie	Angola, Village of	8/6/2002
Erie	Aurora, Town of	4/16/1979
Erie	Blasdell, Village of	6/25/1976 (M)
Erie	Boston, Town of	9/30/1981
Erie	Brant, Town of	1/6/1984 (M)
Erie	Buffalo, City of	9/26/2008
Erie	Cheektowaga, Town of	3/15/1984
Erie	Clarence, Town of	3/5/1996
Erie	Colden, Town of	7/2/1979
Erie	Collins,Town of	9/26/2008
Erie	Concord, Town of	9/4/1986
Erie	Depew, Village of	8/3/1981
Erie	East Aurora, Village of	8/6/2002
Erie	Eden, Town of	8/24/1979 (M)
Erie	Elma,Town of	6/22/1998
Erie	Evans, Town of	2/2/2002
Erie	Farnham, Village of	(NSFHA)
Erie	Grand Island, Town of	9/26/2008
Erie	Hamburg, Town of	12/20/2001
Erie	Hamburg, Village of	1/20/1982
Erie	Holland, Town of	9/26/2008
Erie	Kenmore,Village of	(NSFHA)
Erie	Lackawanna, City of	7/2/1980
Erie	Lancaster, Town of	2/23/2001
Erie	Lancaster, Village of	7/2/1979
Erie	Marilla, Town of	9/29/1978
Erie	Newstead, Town of	5/4/1992
Erie	Orchard Park, Town of	3/16/1983
Erie	Orchard Park, Village of	(NSFHA)
Erie	Sardinia, Town of	1/16/2003
Erie	Sloan, Village of	(NSFHA)
Erie	Springville, Village of	7/17/1986
Erie	Tonawanda, City of	9/26/2008
Erie	Tonawanda, Town of	11/12/1982
Erie	Wales, Town of	9/26/2008
Erie	West Seneca, Town of	9/30/1992
Erie	Williamsville, Village of	9/26/2008
Erie/Cattaraugus	Gowanda, Village of	9/26/2008
Essex	Chesterfield, Town of	5/4/1987
Essex	Crown Point,Town of	7/16/1987

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Essex	Elizabethtown, Town of	1/20/1993
Essex	Essex, Town of	4/3/1987
Essex	Jay, Town of	6/17/2002
Essex	Keene, Town of	6/5/1985 (M)
Essex	Keeseville, Village of	9/28/2007 (M)
Essex	Lake Placid, Village of	(NSFHA)
Essex	Lewis, Town of	5/15/1985 (M)
Essex	Minerva, Town of	10/5/1984 (M)
Essex	Moriah, Town of	9/24/1984 (M)
Essex	Newcomb, Town of	6/5/1985 (M)
Essex	North Elba, Town of	8/23/2001
Essex	North Hudson, Town of	5/15/1985 (M)
Essex	Port Henry, Village of	7/16/1987
Essex	Schroon, Town of	11/16/1995
Essex	St. Armand, Town of	2/5/1986
Essex	Ticonderoga, Town of	9/6/1996
Essex	Westport, Town of	9/4/1987
Essex	Willsboro, Town of	5/18/1992
Essex	Wilmington, Town of	11/16/1995
Franklin	Bangor, Town of	(NSFHA)
Franklin	Bellmont, Town of	8/5/1985 (M)
Franklin	Bombay, Town of	2/15/1985 (M)
Franklin	Brandon, Town of	(NSFHA)
Franklin	Brighton, Town of	(NSFHA)
Franklin	Brushton, Village of	2/19/1986 (M)
Franklin	Burke, Town of	2/19/1986 (M)
Franklin	Burke, Village of	(NSFHA)
Franklin	Chateaugay, Village of	(NSFHA)
Franklin	Constable, Town of	(NSFHA)
Franklin	Dickinson, Town of	3/18/1986 (M)
Franklin	Duane, Town of	(NSFHA)
Franklin	Fort Covington, Town of	12/23/1983 (M)
Franklin	Franklin, Town of	9/24/1984 (M)
Franklin	Harrietstown, Town of	1/3/1985
Franklin	Malone, Town of	9/4/1985 (M)
Franklin	Malone, Village of	4/3/1978
Franklin	Moira, Town of	4/15/1986 (M)
Franklin	Santa Clara, Town of	(NSFHA)
Franklin	Saranac Lake, Village of	1/2/1992
Franklin	Tupper Lake, Town of	(NSFHA)
Franklin	Tupper Lake,Village of	3/1/1987 (L)
Franklin	Waverly, Town of	(NSFHA)
Franklin	Westville, Town of	2/15/1985 (M)
Fulton	Bleecker,Town of	7/18/1985 (M)
Fulton	Broadalbin, Town of	1/3/1985 (M)
Fulton	Broadalbin, Village of	4/15/1986 (M)
Fulton	Caroga, Town of	7/18/1985 (M)
Fulton	Ephratah, Town of	7/3/1985 (M)
Fulton	Gloversville, City of	9/30/1983
Fulton	Johnstown, City of	7/18/1983
Fulton	Johnstown, Town of	7/3/1985 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Fulton	Mayfield, Town of	8/5/1985 (M)
Fulton	Northampton, Town of	8/19/1985 (M)
Fulton	Northville, Village of	(NSFHA)
Fulton	Oppenheim, Town of	6/18/1976 (X)
Fulton	Perth, Town of	2/15/1985 (M)
Fulton	Stratford, Town of	1/3/1985 (M)
Genesee	Alabama, Town of	11/18/1983 (M)
Genesee	Alexander, Village of	5/4/1987
Genesee	Alexander,Town of	5/4/1987
Genesee	Batavia, City of	9/16/1982
Genesee	Batavia, Town of	1/17/1985
Genesee	Bergen, Town of	7/6/1984 (M)
Genesee	Bergen, Village of	6/8/1979 (M)
Genesee	Bethany, Town of	9/24/1984 (M)
Genesee	Byron, Town of	2/1/1988 (L)
Genesee	Corfu, Village of	10/15/1985 (M)
Genesee	Darien, Town of	7/6/1984 (M)
Genesee	Elba, Town of	10/5/1984 (M)
Genesee	Elba, Village of	1/20/1984 (M)
Genesee	Le Roy, Town of	9/14/1979 (M)
Genesee	Le Roy, Village of	8/3/1981
Genesee	Oakfield, Town of	5/25/1984 (M)
Genesee	Oakfield, Village of	3/23/1984 (M)
Genesee	Pavilion, Town of	2/27/1984 (M)
Genesee	Pembroke, Town of	1/20/1984 (M)
Genesee	Stafford,Town of	7/16/1982
Genesee/Wyoming	Attica, Village of	7/3/1986
Greene	Ashland, Town of	5/16/2008
Greene	Athens, Town of	5/16/2008
Greene	Athens, Village of	5/16/2008
Greene	Cairo, Town of	5/16/2008
Greene	Catskill, Town of	5/16/2008
Greene	Catskill, Village of	5/16/2008
Greene	Coxsackie, Town of	5/16/2008
Greene	Coxsackie, Village of	5/16/2008
Greene	Durham, Town of	5/16/2008 (M)
Greene	Greenville, Town of	5/16/2008 (M)
Greene	Halcott, Town of	5/16/2008 (M)
Greene	Hunter, Town of	5/16/2008
Greene	Hunter, Village of	5/16/2008
Greene	Jewett, Town of	5/16/2008
Greene	Lexington, Town of	5/16/2008
Greene	New Baltimore, Town of	5/16/2008 (M)
Greene	Prattsville, Town of	5/16/2008
Greene	Tannersville, Village of	5/16/2008
Greene	Windham, Town of	5/16/2008
Hamilton	Arietta, Town of	(NSFHA)
Hamilton	Benson, Town of	(NSFHA)
Hamilton	Hope, Town of	4/30/1986 (M)
Hamilton	Indian Lake, Town of	12/4/1985 (M)
Hamilton	Inlet, Town of	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Hamilton	Lake Pleasant, Town of	(NSFHA)
Hamilton	Long Lake, Town of	9/24/1984 (M)
Hamilton	Morehouse, Town of	(NSFHA)
Hamilton	Speculator, Village of	2/6/1984 (M)
Hamilton	Wells, Town of	6/3/1986 (M)
Herkimer	Cold Brook, Village of	12/20/2000
Herkimer	Columbia, Town of	7/16/1982 (M)
Herkimer	Danube, Town of	5/12/1999 (M)
Herkimer	Dolgeville, Village of	3/16/1983
Herkimer	Fairfield, Town of	10/18/1988
Herkimer	Frankfort, Town of	12/20/2000
Herkimer	Frankfort, Village of	3/7/2001
Herkimer	German Flatts, Town of	5/15/1985 (M)
Herkimer	Herkimer, Town of	4/17/1985 (M)
Herkimer	Herkimer, Village of	6/17/2002
Herkimer	Ilion, Village of	9/8/1999
Herkimer	Litchfield, Town of	5/7/2001
Herkimer	Little Falls, City of	4/4/1983
Herkimer	Little Falls, Town of	3/28/1980 (M)
Herkimer	Manheim, Town of	5/1/1985 (M)
Herkimer	Middleville, Village of	7/3/1985 (M)
Herkimer	Mohawk, Village of	9/8/1999
Herkimer	Newport, Town of	6/2/1999
Herkimer	Newport, Village of	4/2/1991
Herkimer	Norway, Town of	7/3/1985 (M)
Herkimer	Ohio, Town of	9/24/1984 (M)
Herkimer	Poland, Village of	6/2/1999 (M)
Herkimer	Russia, Town of	6/2/1999
Herkimer	Salisbury, Town of	7/3/1985 (M)
Herkimer	Schuyler, Town of	6/20/2001
Herkimer	Stark, Town of	5/15/1985 (M)
Herkimer	Warren, Town of	(NSFHA)
Herkimer	Webb, Town of	7/30/1982 (M)
Herkimer	West Winfield, Village of	7/3/1985 (M)
Herkimer	Winfield, Town of	7/3/1985 (M)
Jefferson	Adams, Town of	6/5/1985 (M)
Jefferson	Adams, Village of	6/19/1985 (M)
Jefferson	Alexandria Bay, Village of	4/3/1978
Jefferson	Alexandria, Town of	10/15/1985 (M)
Jefferson	Antwerp, Town of	4/15/1986 (M)
Jefferson	Antwerp, Village of	(NSFHA)
Jefferson	Black River, Village of	6/5/1989 (M)
Jefferson	Brownville, Town of	6/2/1992
Jefferson	Brownville, Village of	3/18/1986 (M)
Jefferson	Cape Vincent, Town of	6/2/1992
Jefferson	Cape Vincent, Village of	4/17/1985 (M)
Jefferson	Carthage, Village of	6/17/1991
Jefferson	Champion, Town of	6/2/1993
Jefferson	Chaumont, Village of	9/8/1999
Jefferson	Clayton, Town of	4/2/1986
Jefferson	Clayton, Village of	12/1/1977

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Jefferson	Deferiet, Village of	(NSFHA)
Jefferson	Dexter, Village of	6/15/1994
Jefferson	Ellisburg, Town of	5/18/1992
Jefferson	Ellisburg, Village of	6/19/1985 (M)
Jefferson	Evans Mills, Village of	1/2/1992
Jefferson	Glen Park, Village of	(NSFHA)
Jefferson	Henderson, Town of	5/18/1992
Jefferson	Herrings, Village of	12/18/1985
Jefferson	Hounsfield, Town of	5/18/1992
Jefferson	Leray, Town of	2/2/2002
Jefferson	Lyme, Town of	9/2/1993
Jefferson	Orleans, Town of	3/1/1978
Jefferson	Pamelia, Town of	1/2/1992
Jefferson	Philadelphia, Town of	6/5/1989 (M)
Jefferson	Philadelphia, Village of	9/15/1993
Jefferson	Rodman, Town of	7/3/1985 (M)
Jefferson	Rutland, Town of	8/18/1992
Jefferson	Sackets Harbor, Village of	5/2/1994
Jefferson	Theresa, Town of	10/15/1985 (M)
Jefferson	Theresa, Village of	10/15/1985 (M)
Jefferson	Watertown, City of	8/2/1993
Jefferson	Watertown, Town of	8/2/1993
Jefferson	West Carthage, Village of	9/28/1990
Jefferson	Wilna, Town of	1/16/1992
Jefferson	Worth, Town of	(NSFHA)
Lewis	Castorland, Village of	(NSFHA)
Lewis	Constableville, Village of	7/16/1982 (M)
Lewis	Copenhagen, Village of	(NSFHA)
Lewis	Crogham, Village of	5/15/1985 (M)
Lewis	Croghan, Town of	5/15/1985 (M)
Lewis	Denmark, Town of	5/15/1985 (M)
Lewis	Diana, Town of	9/24/1984 (M)
Lewis	Greig, Town of	5/15/1985 (M)
Lewis	Harrisburg, Town of	(NSFHA)
Lewis	Harrisville, Village of	9/24/1984 (M)
Lewis	Lewis, Town of	9/29/1996
Lewis	Leyden, Town of	6/19/1985 (M)
Lewis	Lowville, Town of	6/20/2000
Lewis	Lowville, Village of	6/20/2000
Lewis	Lyons Falls, Village of	6/19/1985 (M)
Lewis	Lyonsdale, Town of	6/19/1985 (M)
Lewis	Martinsburg, Town of	6/19/1985 (M)
Lewis	New Bremen, Town of	5/4/2000
Lewis	Osceola, Town of	6/30/1976 (M)
Lewis	Pinckney, Town of	(NSFHA)
Lewis	Port Leyden, Village of	6/19/1985 (M)
Lewis	Turin, Town of	8/2/1994
Lewis	Turin, Village of	7/1/1977 (M)
Lewis	Watson, Town of	7/19/2000
Lewis	West Turin, Town of	(NSFHA)
Livingston	Avon, Town of	8/15/1978

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Livingston	Avon, Village of	8/1/1978
Livingston	Caledonia, Town of	6/1/1981
Livingston	Caledonia, Village of	6/1/1981
Livingston	Conesus, Town of	2/15/1991
Livingston	Dansville, Village of	11/1/1978
Livingston	Geneseo, Town of	9/29/1996
Livingston	Geneseo, Village of	9/29/1996
Livingston	Groveland, Town of	2/15/1991
Livingston	Leicester, Town of	1/20/1982
Livingston	Leicester, Village of	8/27/1982 (M)
Livingston	Lima, Town of	12/23/1983 (M)
Livingston	Lima, Village of	7/23/1982 (M)
Livingston	Livonia, Town of	2/19/1992
Livingston	Livonia, Village of	6/1/1988 (L)
Livingston	Mount Morris, Town of	(NSFHA)
Livingston	Mount Morris, Village of	8/1/1978
Livingston	North Dansville, Town of	12/4/1979
Livingston	Nunda, Town of	7/3/1985 (M)
Livingston	Nunda, Village of	3/23/1984 (M)
Livingston	Ossian, Town of	6/8/1984 (M)
Livingston	Portage,Town of	12/18/1984
Livingston	Sparta, Town of	8/27/1982 (M)
Livingston	Springwater, Town of	8/24/1984 (M)
Livingston	West Sparta, Town of	7/18/1985
Livingston	York, Town of	1/20/1982
Madison	Brookfield, Town of	4/17/1985 (M)
Madison	Canastota , Village of	4/15/1988
Madison	Cazenovia, Town of	6/19/1985
Madison	Cazenovia, Village of	6/19/1985
Madison	Chittenango, Village of	2/1/1985 (M)
Madison	De Ruyter, Town of	6/8/1984
Madison	De Ruyter, Village of	8/24/1984 (M)
Madison	Eaton, Town of	9/10/1984 (M)
Madison	Fenner, Township of	2/5/1986
Madison	Georgetown, Town of	11/2/1984 (M)
Madison	Hamilton, Town of	9/27/2002
Madison	Hamilton,Village	9/27/2002
Madison	Lebanon, Town of	4/17/1985 (M)
Madison	Lenox, Town of	6/3/1988
Madison	Lincoln, Town of	9/4/1985 (M)
Madison	Madison, Town of	1/19/1983
Madison	Morrisville, Village of	4/15/1982
Madison	Munnsville, Village of	9/15/1983
Madison	Nelson, Town of	10/5/1984 (M)
Madison	Oneida, City of	2/23/2001
Madison	Smithfield, Town of	4/17/1985 (M)
Madison	Stockbridge, Town of	(NSFHA)
Madison	Sullivan, Town of	5/15/1986
Madison	Wampsville, Village of	(NSFHA)
Monroe	Brighton, Town of	8/28/2008
Monroe	Brockport, Village of	8/28/2008 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Monroe	Chili, Town of	8/28/2008
Monroe	Churchville, Village of	8/28/2008
Monroe	Clarkson, Town of	8/28/2008
Monroe	East Rochester, Village of	8/28/2008 (M)
Monroe	Fairport, Village of	8/28/2008
Monroe	Gates, Town of	8/28/2008
Monroe	Greece, Town of	8/28/2008
Monroe	Hamlin, Town of	8/28/2008
Monroe	Henrietta, Town of	8/28/2008
Monroe	Hilton, Village of	8/28/2008
Monroe	Honeoye Falls, Village of	8/28/2008
Monroe	Irondequoit, Town of	8/28/2008
Monroe	Mendon, Town of	8/28/2008
Monroe	Ogden, Town of	8/28/2008
Monroe	Parma, Town of	8/28/2008
Monroe	Penfield, Town of	8/28/2008
Monroe	Perinton, Town of	8/28/2008
Monroe	Pittsford, Town of	8/28/2008
Monroe	Pittsford, Village of	8/28/2008 (M)
Monroe	Riga, Town of	8/28/2008
Monroe	Rochester, City of	8/28/2008
Monroe	Rush, Town of	8/28/2008
Monroe	Scottsville, Village of	8/28/2008
Monroe	Spencerport, Village of	8/28/2008
Monroe	Sweden, Town of	8/28/2008 (M)
Monroe	Webster, Town of	8/28/2008
Monroe	Webster, Village of	8/28/2008
Monroe	Wheatland, Town of	8/28/2008
Montgomery	Ames, Village of	12/4/1985 (S)
Montgomery	Amsterdam, City of	6/19/1985
Montgomery	Amsterdam, Town of	12/1/1987 (L)
Montgomery	Canajoharie, Town of	1/6/1983
Montgomery	Canajoharie, Village of	11/3/1982
Montgomery	Charleston, Town of	10/15/1985 (M)
Montgomery	Florida, Town of	12/1/1987 (L)
Montgomery	Fonda, Village of	7/6/1983
Montgomery	Fort Johnson, Village of	1/19/1983
Montgomery	Fort Plain, Village of	6/17/2002
Montgomery	Fultonville, Village of	10/15/1982
Montgomery	Glen, Town of	2/19/1986 (M)
Montgomery	Hagaman, Village of	3/18/1986 (M)
Montgomery	Minden, Town of	1/19/1983
Montgomery	Mohawk, Town of	8/5/1985 (M)
Montgomery	Nelliston, Village of	11/3/1982 (S)
Montgomery	Palatine Bridge, Village of	11/17/1982
Montgomery	Palatine, Town of	5/4/1987
Montgomery	Root, Town of	4/1/1988 (L)
Montgomery	St. Johnsville, City of	9/29/1989
Montgomery	St. Johnsville, Town of	3/16/1983
Nassau	Atlantic Beach, Village of	9/11/2009 (>)
Nassau	Baxter Estates, Village of	9/11/2009 (>)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Nassau	Bayville, Village of	9/11/2009 (>)
Nassau	Cedarhurst, Village of	7/20/1998
Nassau	Centre Island, Village of	9/11/2009 (>)
Nassau	Cove Neck, Village of	9/11/2009 (>)
Nassau	East Hills, Village of	(NSFHA)
Nassau	East Rockaway, Village of	9/11/2009 (>)
Nassau	East Williston, Village of	(NSFHA)
Nassau	Floral Park, Village of	(NSFHA)
Nassau	Flower Hill, Village of	9/11/2009 (>)
Nassau	Freeport, Village of	9/11/2009 (>)
Nassau	Garden City, Village of	(NSFHA)
Nassau	Glen Cove, City of	9/11/2009 (>)
Nassau	Great Neck Estates, Village of	9/11/2009 (>)
Nassau	Great Neck Plaza, Village of	9/11/2009 (>)
Nassau	Great Neck, Village of	9/11/2009 (>)
Nassau	Hempstead, Town of	9/11/2009 (>)
Nassau	Hempstead, Village of	(NSFHA)
Nassau	Hewlett Bay Park, Village of	9/11/2009 (>)
Nassau	Hewlett Harbor, Village of	9/11/2009 (>)
Nassau	Hewlett Neck, Village of	9/11/2009 (>)
Nassau	Island Park, Village of	9/11/2009 (>)
Nassau	Kensington, Village of	9/11/2009 (>)
Nassau	Kings Point, Village of	9/11/2009 (>)
Nassau	Lake Success, Village of	(NSFHA)
Nassau	Lattingtown, Village of	9/11/2009 (>)
Nassau	Laurel Hollow, Village of	9/11/2009 (>)
Nassau	Lawrence, Village of	9/11/2009 (>)
Nassau	Long Beach, City of	9/11/2009 (>)
Nassau	Lynbrook, Village of	9/11/2009 (>)
Nassau	Malverne, Village of	9/11/2009 (>)
Nassau	Manorhaven, Village of	9/11/2009 (>)
Nassau	Massapequa Park, Village of	9/11/2009 (>)
Nassau	Mill Neck, Village of	9/11/2009 (>)
Nassau	Mineola, Village of	(NSFHA)
Nassau	Munsey Park, Village of	(NSFHA)
Nassau	New Hyde Park, Village of	(NSFHA)
Nassau	North Hempstead, Town of	9/11/2009 (>)
Nassau	North Hills, Village of	(NSFHA)
Nassau	Oyster Bay Cove, Village of	9/11/2009 (>)
Nassau	Oyster Bay, Town of	9/11/2009 (>)
Nassau	Plandome Heights, Village of	9/11/2009 (>)
Nassau	Plandome Manor, Village of	9/11/2009 (>)
Nassau	Plandome, Village of	9/11/2009 (>)
Nassau	Port Washington North, Village of	9/11/2009 (>)
Nassau	Rockville Centre, Village of	9/11/2009 (>)
Nassau	Roslyn Estates, Village of	(NSFHA)
Nassau	Roslyn Harbor, Village of	9/11/2009 (>)
Nassau	Roslyn, Village of	9/11/2009 (>)
Nassau	Russell Gardens, Village of	9/11/2009 (>)
Nassau	Saddle Rock, Village of	9/11/2009 (>)
Nassau	Sands Point, Village of	9/11/2009 (>)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Nassau	Sea Cliff, Village of	9/11/2009 (>)
Nassau	Stewart Manor, Village of	(NSFHA)
Nassau	Thomaston, Village of	9/11/2009 (>)
Nassau	Valley Stream, Village of	9/11/2009 (>)
Nassau	Westbury, Village of	(NSFHA)
Nassau	Woodsburgh, Village of	9/11/2009 (>)
Niagara	Barker, Village of	5/1/1984
Niagara	Cambria, Town of	9/30/1983
Niagara	Hartland, Town of	10/7/1983 (M)
Niagara	Lewiston, Town of	6/18/1980
Niagara	Lewiston, Village of	(NSFHA)
Niagara	Lockport, City of	2/4/1981
Niagara	Lockport, Town of	10/4/2002
Niagara	Middleport, Village of	8/1/1983
Niagara	Newfane, Town of	11/18/1981
Niagara	Niagara Falls, City of	9/5/1990
Niagara	Niagara, Town of	6/15/1984
Niagara	North Tonawanda, City of	1/6/1982
Niagara	Pendleton, Town of	1/6/1982
Niagara	Porter, Town of	8/15/1983
Niagara	Royalton, Town of	7/6/1979 (M)
Niagara	Somerset, Town of	2/3/1982
Niagara	Wheatfield, Town of	11/4/1992
Niagara	Wilson, Town of	4/1/1981
Niagara	Wilson, Village of	11/19/1980
Niagara	Youngstown, Village of	6/4/1980
Oneida	Annsville, Town of	4/5/1988
Oneida	Augusta, Town of	5/1/1985 (M)
Oneida	Ava, Town of	2/1/1985 (M)
Oneida	Barneveld, Village of	3/23/1999
Oneida	Boonville, Town of	7/3/1985 (M)
Oneida	Boonville, Village of	4/17/1985 (M)
Oneida	Bridgewater, Town of	(NSFHA)
Oneida	Bridgewater, Village of	4/15/1982
Oneida	Camden, Town of	9/7/1998
Oneida	Camden, Village of	8/16/1988
Oneida	Clayville, Village of	7/5/1983
Oneida	Clinton, Village of	5/1/1985
Oneida	Deerfield, Town of	6/2/1999
Oneida	Florence, Town of	4/17/1985 (M)
Oneida	Floyd, Town of	3/15/1984
Oneida	Forestport, Town of	4/17/1985 (M)
Oneida	Holland Patent, Village of	5/21/2001
Oneida	Kirkland, Town of	4/3/1985
Oneida	Lee, Town of	8/3/1998
Oneida	Marcy, Town of	6/1/1984
Oneida	Marshall, Town of	9/30/1982
Oneida	New Hartford, Town of	4/18/1983
Oneida	New Hartford, Village of	7/5/1983
Oneida	New York Mills, Village of	5/4/2000
Oneida	Oneida Castle, Village of	7/4/1989

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Oneida	Oriskany Falls, Village of	1/19/1983
Oneida	Oriskany, Village of	9/15/1983
Oneida	Paris, Town of	9/15/1983
Oneida	Prospect, Village of	11/20/2000 (S)
Oneida	Remsen, Town of	5/1/1985 (M)
Oneida	Remsen, Village of	9/24/1984 (M)
Oneida	Rome, City of	9/21/1998
Oneida	Sangerfield, Town of	6/5/1985
Oneida	Sherrill, City of	9/15/1983
Oneida	Steuben, Town of	9/24/1984 (M)
Oneida	Sylvan Beach, Village of	6/2/1999
Oneida	Trenton, Town of	9/7/1998
Oneida	Utica, City of	2/1/1984
Oneida	Vernon, Town of	8/16/1988
Oneida	Vernon, Village of	4/15/1988
Oneida	Verona, Town of	10/20/1999
Oneida	Vienna, Town of	10/20/1999
Oneida	Waterville, Village of	8/2/1982
Oneida	Western, Town of	5/4/1989
Oneida	Westmoreland, Town of	3/2/1983
Oneida	Whitesboro, Village of	5/4/2000
Oneida	Whitestown, Town of	5/4/2000
Oneida	Yorkville, Village of	5/4/2000
Onondaga	Baldwinsville, Village of	3/1/1984
Onondaga	Camillus, Town of	5/18/1999
Onondaga	Camillus, Village of	5/18/1999
Onondaga	Cicero, Town of	9/15/1994
Onondaga	Clay, Town of	3/16/1992
Onondaga	Dewitt, Town of	3/1/1979
Onondaga	East Syracuse, Village of	8/3/1981
Onondaga	Elbridge, Town of	8/16/1982
Onondaga	Elbridge, Village of	8/16/1982
Onondaga	Fabius, Town of	4/30/1986 (M)
Onondaga	Fayetteville, Village of	4/17/1985
Onondaga	Geddes, Town of	2/17/1982
Onondaga	Jordan, Village of	8/16/1982
Onondaga	Lafayette, Town of	4/3/1985
Onondaga	Liverpool, Village of	2/4/1981
Onondaga	Lysander, Town of	2/4/1983
Onondaga	Manlius, Town of	9/17/1992
Onondaga	Manlius, Village of	8/1/1984
Onondaga	Marcellus, Town of	8/16/1982
Onondaga	Marcellus, Village of	6/1/1982
Onondaga	Minoa, Village of	9/2/1982
Onondaga	North Syracuse, Village of	(NSFHA)
Onondaga	Onondaga, Town of	6/17/1991
Onondaga	Otisco, Town of	6/3/1986 (M)
Onondaga	Pompey, Town of	10/8/1982
Onondaga	Salina, Town of	8/16/1982
Onondaga	Skaneateles, Town of	6/1/1982
Onondaga	Skaneateles, Village of	2/17/1982

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Onondaga	Solvay, Village of	(NSFHA)
Onondaga	Spafford, Town of	4/30/1986 (M)
Onondaga	Syracuse, City of	5/15/1986
Onondaga	Tully, Town of	4/30/1986 (M)
Onondaga	Tully, Village of	1/19/1983
Onondaga	Van Buren, Town of	3/1/1984
Ontario	Bloomfield, Village of	1/1/1950
Ontario	Bristol, Town of	1/20/1984 (M)
Ontario	Canadice, Town of	5/15/1984
Ontario	Canandaigua, City of	9/24/1982
Ontario	Canandaigua, Town of	3/3/1997
Ontario	Clifton Springs, Village of	7/23/1982 (M)
Ontario	East Bloomfield, Town of	8/15/1983
Ontario	Farmington, Town of	9/30/1983
Ontario	Geneva, City of	4/15/1982
Ontario	Geneva, Town of	2/15/1978
Ontario	Gorham, Town of	12/5/1996
Ontario	Hopewell, Town of	2/27/1984 (M)
Ontario	Manchester, Town of	3/9/1984 (M)
Ontario	Manchester, Village of	1/20/1984 (M)
Ontario	Naples, Town of	6/8/1984 (M)
Ontario	Naples, Village of	9/30/1977
Ontario	Phelps, Town of	12/3/1982 (M)
Ontario	Phelps, Village of	1/20/1984 (M)
Ontario	Richmond, Town of	12/18/1984
Ontario	Seneca, Town of	6/22/1984 (M)
Ontario	Shortsville, Village of	9/24/1984 (M)
Ontario	South Bristol, Town of	5/18/1998
Ontario	Victor, Town of	9/30/1983
Ontario	Victor, Village of	5/17/2004
Ontario	West Bloomfield, Town of	6/1/1978
Orange	Blooming Grove, Town of	11/15/1985
Orange	Chester, Town of	6/4/1996
Orange	Chester, Village of	9/18/1986
Orange	Cornwall On The Hudson, Village of	8/2/1982
Orange	Cornwall, Town of	9/30/1982
Orange	Crawford, Town of	9/30/1982
Orange	Deer Park, Town of	10/20/1999
Orange	Florida, Village of	12/4/1986
Orange	Goshen, Town of	4/30/1986
Orange	Goshen, Village of	4/30/1986
Orange	Greenville, Town of	3/4/1985
Orange	Greenwood Lake, Village of	6/15/1979
Orange	Hamptonburgh, Town of	7/3/1986
Orange	Harriman, Village of	9/1/1983
Orange	Highland Falls, Village of	5/19/1987
Orange	Highlands, Township of	5/19/1987
Orange	Kiryas Joel, Village of	6/14/2002
Orange	Maybrook, Village of	1/1/1950
Orange	Middletown, City of	3/2/1983
Orange	Minisink, Town of	4/3/1985

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Orange	Monroe, Town of	2/23/2001
Orange	Monroe, Village of	1/6/1982
Orange	Montgomery, Town of	10/16/1984
Orange	Montgomery, Village of	10/16/1984
Orange	Mount Hope, Town of	10/5/1984 (M)
Orange	New Windsor, Town of	12/15/1978
Orange	Newburgh, City of	6/5/1985
Orange	Newburgh, Town of	6/5/1985
Orange	Port Jervis, City of	4/2/2002
Orange	South Blooming Grove, Village of	1/1/1950
Orange	Tuxedo Park, Village of	1/1/1950
Orange	Tuxedo, Town of	4/15/1982
Orange	Unionville, Village of	7/6/1984 (M)
Orange	Walden, Village of	8/15/1984
Orange	Wallkill, Town of	9/4/1986
Orange	Warwick, Town of	10/15/1985
Orange	Warwick, Village of	2/17/1988
Orange	Washingtonville, Village of	4/1/1981
Orange	Wawayanda, Town of	3/4/1985
Orange	Woodbury, Village of	3/18/1987
Orleans	Albion, Town of	8/8/1980 (M)
Orleans	Albion, Village of	11/30/1979 (M)
Orleans	Barre, Town of	10/15/1981 (M)
Orleans	Carlton, Town of	11/1/1978
Orleans	Clarendon,Town of	(NSFHA)
Orleans	Gaines, Town of	6/8/1984 (M)
Orleans	Holley, Village of	11/30/1979 (M)
Orleans	Kendall, Town of	5/1/1978
Orleans	Lyndonville, Village of	9/16/1981
Orleans	Medina, Village of	3/28/1980 (M)
Orleans	Murray, Town of	3/21/1980 (M)
Orleans	Ridgeway,Town of	9/14/1979 (M)
Orleans	Shelby,Town of	12/23/1983 (M)
Orleans	Yates, Town of	9/29/1978
Oswego	Albion, Town of	4/15/1986 (M)
Oswego	Altmar, Village of	2/5/1986 (M)
Oswego	Amboy, Town of	3/1/1988 (L)
Oswego	Boylston, Town of	(NSFHA)
Oswego	Central Square,Village of	(NSFHA)
Oswego	Cleveland, Village of	6/1/1982
Oswego	Constantia, Town of	11/3/1982
Oswego	Fulton, City of	4/15/1982
Oswego	Granby, Town of	9/16/1982
Oswego	Hannibal, Town of	2/1/1988 (L)
Oswego	Hannibal, Village of	4/1/1987 (L)
Oswego	Hastings, Town of	1/19/1983
Oswego	Lacona, Village of	5/11/1979 (M)
Oswego	Mexico, Town of	10/15/1981
Oswego	Mexico, Village of	10/15/1981
Oswego	Minetto, Town of	9/30/1981
Oswego	New Haven, Town of	11/2/1995

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Oswego	Orwell, Town of	2/19/1986 (S)
Oswego	Oswego, City of	11/22/1999
Oswego	Oswego, Town of	6/20/2001
Oswego	Palermo, Town of	3/1/1988 (S)
Oswego	Parish, Town of	4/15/1986 (M)
Oswego	Parish, Village of	2/19/1986 (M)
Oswego	Phoenix, Village of	2/17/1982
Oswego	Pulaski, Village of	9/2/1982
Oswego	Redfield, Town of	4/1/1991 (L)
Oswego	Richland, Town of	7/17/1995
Oswego	Sandy Creek, Town of	7/17/1995
Oswego	Sandy Creek, Village of	5/11/1979 (M)
Oswego	Schroeppel, Town of	8/2/1982
Oswego	Scriba, Town of	6/6/2001
Oswego	Volney, Town of	4/15/1982
Oswego	West Monroe, Town of	1/20/1982
Oswego	Williamstown, Town of	3/1/1988 (S)
Otsego	Burlington, Town of	10/21/1983 (M)
Otsego	Butternuts, Town of	12/23/1983 (M)
Otsego	Cherry Valley, Town of	2/1/1988 (L)
Otsego	Cherry Valley, Village of	1/3/1986 (M)
Otsego	Cooperstown, Village of	5/4/2000
Otsego	Decatur, Town of	6/18/1987
Otsego	Edmeston, Town of	6/1/1987 (L)
Otsego	Exeter, Town of	11/18/1983 (M)
Otsego	Gilbertsville, Village of	11/1/1985 (M)
Otsego	Hartwick, Town of	11/4/1983 (M)
Otsego	Laurens, Town of	5/15/1985 (M)
Otsego	Laurens, Village of	4/17/1987 (M)
Otsego	Maryland, Town of	6/3/1986 (M)
Otsego	Middlefield, Town of	6/1/1988 (L)
Otsego	Milford, Town of	5/19/1987 (M)
Otsego	Milford, Village of	11/18/1983 (S)
Otsego	Morris, Town of	1/3/1986 (M)
Otsego	Morris, Village of	12/4/1985 (M)
Otsego	New Lisbon, Town of	11/18/1983 (M)
Otsego	Oneonta, City of	9/29/1978
Otsego	Oneonta, Town of	10/17/1986
Otsego	Otego, Town of	2/4/1987
Otsego	Otego, Village of	11/5/1986
Otsego	Otsego, Town of	6/1/1987 (L)
Otsego	Pittsfield, Town of	11/4/1983 (M)
Otsego	Plainfield, Town of	11/4/1983 (M)
Otsego	Richfield Springs, Village of	1/3/1986 (M)
Otsego	Richfield, Town of	4/15/1986 (M)
Otsego	Roseboom, Town of	6/1/1988 (S)
Otsego	Springfield, Town of	6/1/1987 (L)
Otsego	Unadilla, Town of	9/30/1987
Otsego	Unadilla, Village of	9/30/1987
Otsego	Westford, Town of	6/1/1988 (L)
Otsego	Worcester, Town of	6/1/1988 (L)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Putnam	Brewster, Village of	9/18/1986
Putnam	Carmel,Town of	10/19/2001
Putnam	Cold Spring, Village of	3/15/1984
Putnam	Kent, Town of	9/4/1986
Putnam	Nelsonville, Village of	9/10/1984 (M)
Putnam	Patterson, Town of	7/3/1986
Putnam	Philipstown,Town of	6/18/1987
Putnam	Putnam Valley, Town of	6/20/2001
Putnam	Southeast, Town of	9/4/1986
Rensselaer	Berlin, Town of	8/17/1979 (M)
Rensselaer	Brunswick, Town of	12/6/2000
Rensselaer	Castleton-On-Hudson, Village of	11/15/1984
Rensselaer	East Greenbush, Town of	3/18/1980
Rensselaer	East Nassau, Village of	9/5/1984
Rensselaer	Grafton, Town of	10/13/1978 (M)
Rensselaer	Hoosick Falls, Village of	2/4/2005
Rensselaer	Hoosick, Town of	8/1/1987 (L)
Rensselaer	Nassau, Town of	9/5/1984
Rensselaer	Nassau, Village of	5/18/1979 (M)
Rensselaer	North Greenbush,Town of	6/18/1980
Rensselaer	Petersburg, Town of	9/1/1978 (M)
Rensselaer	Pittstown, Town of	9/5/1990
Rensselaer	Poestenkill, Town of	9/2/1981
Rensselaer	Rensselaer, City of	3/18/1980
Rensselaer	Sand Lake, Town of	5/15/1980
Rensselaer	Schaghticoke, Town of	7/16/1984
Rensselaer	Schaghticoke, Village of	6/5/1985
Rensselaer	Schodack, Town of	8/15/1984
Rensselaer	Stephentown, Town of	8/3/1981
Rensselaer	Troy, City of	3/18/1980
Rensselaer	Valley Falls, Village of	6/5/1985
Richmond/Queens/ New York/Kings/Bronx	New York, City of	9/5/2007
Rockland	Chestnut Ridge, Village of	9/16/1988
Rockland	Clarkstown, Town of	5/21/2001
Rockland	Grand View-On-Hudson, Village of	10/15/1981
Rockland	Haverstraw, Town of	1/6/1982
Rockland	Haverstraw, Village of	9/2/1981
Rockland	Hillburn, Village of	9/20/1996
Rockland	Kaser, Village of	1/1/1950
Rockland	Montebello, Village of	1/18/1989
Rockland	New Hempstead, Village of	12/16/1988
Rockland	New Square, Village of	(NSFHA)
Rockland	Nyack, Village of	12/4/1985
Rockland	Orangetown, Town of	8/2/1982
Rockland	Piermont, Village of	11/17/1982
Rockland	Pomona, Village of	4/15/1982
Rockland	Ramapo, Town of	2/2/1989
Rockland	Sloatsburg, Village of	1/6/1982
Rockland	South Nyack, Village of	11/4/1981
Rockland	Spring Valley, Village of	8/16/1988

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Rockland	Stony Point, Town of	9/30/1981
Rockland	Suffern, Village of	3/28/1980
Rockland	Upper Nyack, Village of	(NSFHA)
Rockland	Wesley Hills, Village of	9/16/1988
Rockland	West Haverstraw, Village of	9/30/1981
Saratoga	Ballston Spa, Village of	8/16/1995
Saratoga	Ballston, Town of	8/16/1995
Saratoga	Charlton, Town of	8/16/1995
Saratoga	Clifton Park, Town of	8/16/1995
Saratoga	Corinth, Town of	8/16/1995
Saratoga	Corinth, Village of	8/16/1995
Saratoga	Day, Town of	(NSFHA)
Saratoga	Galway, Town of	8/16/1995
Saratoga	Greenfield, Town of	8/16/1995
Saratoga	Hadley, Town of	8/16/1995
Saratoga	Halfmoon, Town of	8/16/1995
Saratoga	Malta, Town of	8/16/1995
Saratoga	Mechanicville, City of	8/16/1995
Saratoga	Milton, Town of	8/16/1995
Saratoga	Moreau, Town of	8/16/1995
Saratoga	Northumberland, Town of	8/16/1995
Saratoga	Providence, Town of	8/16/1995
Saratoga	Round Lake, Village of	8/16/1995
Saratoga	Saratoga Springs, City of	8/16/1995
Saratoga	Saratoga, Town of	8/16/1995
Saratoga	Schuylerville, Village of	8/16/1995
Saratoga	South Glens Falls, Village of	8/16/1995
Saratoga	Stillwater, Town of	8/16/1995
Saratoga	Stillwater, Village of	8/16/1995
Saratoga	Victory, Village of	8/16/1995
Saratoga	Waterford, Town of	8/16/1995
Saratoga	Waterford, Village of	8/16/1995
Saratoga	Wilton,Town of	(NSFHA)
Schenectady	Delanson, Village of	5/25/1984 (M)
Schenectady	Duanesburg, Town of	2/17/1989
Schenectady	Glenville,Town of	5/4/1987
Schenectady	Niskayuna, Town of	3/1/1978
Schenectady	Princetown, Town of	7/1/1988 (L)
Schenectady	Rotterdam, Town of	6/15/1984
Schenectady	Schenectady, City of	9/30/1983
Schenectady	Scotia, Village of	6/1/1984
Schoharie	Blenheim, Town of	4/2/2004
Schoharie	Broome, Town of	4/2/2004
Schoharie	Carlisle, Town of	4/2/2004
Schoharie	Cobleskill, Town of	4/2/2004
Schoharie	Cobleskill, Village of	4/2/2004
Schoharie	Conesville, Town of	4/2/2004
Schoharie	Esperance, Town of	4/2/2004
Schoharie	Esperance, Village of	4/2/2004
Schoharie	Fulton, Town of	4/2/2004
Schoharie	Gilboa, Town of	4/2/2004

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Schoharie	Jefferson, Town of	4/2/2004
Schoharie	Middleburgh, Town of	4/2/2004
Schoharie	Middleburgh, Village of	4/2/2004
Schoharie	Richmondville, Town of	4/2/2004
Schoharie	Richmondville, Village of	4/2/2004
Schoharie	Schoharie, Town of	4/2/2004
Schoharie	Schoharie, Village of	4/2/2004
Schoharie	Seward, Town of	4/2/2004
Schoharie	Sharon Spring, Village of	4/2/2004 (M)
Schoharie	Sharon, Town of	4/2/2004
Schoharie	Summit, Town of	4/2/2004
Schoharie	Wright, Town of	4/2/2004
Schuyler	Burdett, Village of	6/1/1988 (L)
Schuyler	Catharine, Town of	4/20/1984 (M)
Schuyler	Cayuta, Town of	9/24/1984 (M)
Schuyler	Dix, Town of	10/29/1982 (M)
Schuyler	Hector, Town of	7/20/1984 (M)
Schuyler	Montour Falls, Village of	9/15/1983
Schuyler	Montour, Town of	3/1/1988 (L)
Schuyler	Odessa, Village of	4/20/1984 (M)
Schuyler	Orange, Town of	4/20/1984 (M)
Schuyler	Reading, Town of	(NSFHA)
Schuyler	Tyrone, Town of	7/6/1984 (M)
Schuyler	Watkins Glen, Village of	7/17/1978
Seneca	Covert, Town of	6/8/1984 (M)
Seneca	Fayette, Town of	1/15/1988
Seneca	Lodi, Town of	1/15/1988
Seneca	Lodi, Village of	(NSFHA)
Seneca	Ovid, Town of	1/15/1988
Seneca	Romulus, Town of	6/5/1985 (M)
Seneca	Seneca Falls, Town of	8/3/1981
Seneca	Seneca Falls, Village of	8/3/1981
Seneca	Tyre, Town of	8/31/1979 (M)
Seneca	Varick, Town of	12/17/1987
Seneca	Waterloo, Town of	9/16/1981
Seneca	Waterloo, Village of	8/3/1981
St. Lawrence	Brasher, Town of	1/3/1986 (M)
St. Lawrence	Canton, Town of	8/17/1998
St. Lawrence	Canton, Village of	5/2/1994
St. Lawrence	Clare, Town of	7/16/1982 (M)
St. Lawrence	Clifton, City of	5/15/1986 (M)
St. Lawrence	Colton, Town of	5/1/1985 (M)
St. Lawrence	De Kalb, Town of	(NSFHA)
St. Lawrence	De Peyster, Town of	7/23/1982 (M)
St. Lawrence	Edwards, Town of	7/30/1982 (M)
St. Lawrence	Edwards, Village of	7/23/1982 (M)
St. Lawrence	Fine, Town of	5/1/1985 (M)
St. Lawrence	Fowler, Town of	6/5/1989 (M)
St. Lawrence	Gouverneur, Town of	8/6/1982 (M)
St. Lawrence	Gouverneur, Village of	3/3/1997
St. Lawrence	Hammond, Town of	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
St. Lawrence	Hermon, Town of	(NSFHA)
St. Lawrence	Hermon, Village of	8/3/1998
St. Lawrence	Heuvelton, Village of	4/30/1986 (M)
St. Lawrence	Hopkinton, Town of	11/12/1982 (M)
St. Lawrence	Lawrence, Town of	(NSFHA)
St. Lawrence	Lisbon, Town of	(NSFHA)
St. Lawrence	Louisville, Town of	(NSFHA)
St. Lawrence	Macomb, Town of	(NSFHA)
St. Lawrence	Madrid, Town of	(NSFHA)
St. Lawrence	Massena, Town of	6/17/1986 (M)
St. Lawrence	Massena, Village of	11/5/1980
St. Lawrence	Morristown, Town of	8/6/1982 (M)
St. Lawrence	Morristown, Village of	12/2/1980 (M)
St. Lawrence	Norfolk, Town of	4/15/1986 (M)
St. Lawrence	Norwood, Village of	4/30/1986 (M)
St. Lawrence	Ogdensburg, City of	11/5/1980
St. Lawrence	Oswegatchie, Town of	5/1/1985 (M)
St. Lawrence	Parishville, Town of	7/30/1982 (M)
St. Lawrence	Piercefield, Town of	1/6/1984 (M)
St. Lawrence	Pierrepont, Town of	(NSFHA)
St. Lawrence	Pitcairn, Town of	8/13/1982 (M)
St. Lawrence	Potsdam, Village of	1/5/1996
St. Lawrence	Potsdam,Town of	3/4/1986 (M)
St. Lawrence	Rensselaer Falls, Village of	1/6/1984 (M)
St. Lawrence	Richville, Village of	1/6/1984 (M)
St. Lawrence	Rossie, Town of	7/30/1982 (M)
St. Lawrence	Russell, Town of	(NSFHA)
St. Lawrence	Stockholm, Town of	4/15/1986 (M)
St. Lawrence	Waddington, Town of	4/15/1986 (M)
St. Lawrence	Waddington, Village of	5/11/1979 (M)
Steuben	Addison, Town of	12/18/1984
Steuben	Addison, Village of	6/15/1981
Steuben	Arkport, Village of	3/4/1980
Steuben	Avoca, Town of	2/5/1992
Steuben	Avoca, Village of	5/16/1983
Steuben	Bath, Town of	5/2/1983
Steuben	Bath, Village of	3/16/1983
Steuben	Bradford, Town of	9/24/1984 (M)
Steuben	Cameron, Town of	5/15/1991
Steuben	Campbell, Town of	6/11/1982
Steuben	Canisteo, Town of	12/18/1984
Steuben	Canisteo, Village of	5/18/1979 (M)
Steuben	Caton, Town of	3/23/1984 (M)
Steuben	Cohocton, Town of	5/16/1983
Steuben	Cohocton, Village of	5/16/1983
Steuben	Corning, City of	9/27/2002
Steuben	Corning, Town of	9/27/2002
Steuben	Dansville, Town of	3/9/1984 (M)
Steuben	Erwin, Town of	7/2/1980
Steuben	Fremont, Town of	10/29/1982 (M)
Steuben	Greenwood, Town of	9/3/1982 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Steuben	Hammondsport, Village of	4/17/1978
Steuben	Hartsville, Town of	9/17/1982 (M)
Steuben	Hornby, Town of	4/15/1986
Steuben	Hornell, City of	3/18/1980
Steuben	Hornellsville, Town of	7/16/1980
Steuben	Howard, Town of	9/3/1982 (M)
Steuben	Jasper, Town of	7/23/1982 (M)
Steuben	Lindley, Town of	8/1/1980
Steuben	North Hornell, Village of	1/17/1986
Steuben	Painted Post, Village of	5/18/2000
Steuben	Prattsburg, Town of	1/20/1984 (M)
Steuben	Pulteney, Town of	9/30/1977
Steuben	Rathbone, Town of	12/3/1982 (M)
Steuben	Riverside, Village of	5/15/1980
Steuben	Savona, Village of	8/15/1980
Steuben	South Corning, Village of	10/15/1981
Steuben	Thurston, Town of	2/11/1983 (M)
Steuben	Troupsburg, Town of	9/24/1982 (M)
Steuben	Tuscarora, Town of	3/1/1988 (L)
Steuben	Urbana, Town of	1/19/1978
Steuben	Wayland, Town of	6/8/1984 (M)
Steuben	Wayland, Village of	8/1/1988 (L)
Steuben	Wayne, Town of	11/2/1977
Steuben	West Union, Town of	7/1/1988 (L)
Steuben	Wheeler, Town of	7/25/1980 (M)
Steuben	Woodhull, Town of	4/2/1991
Steuben/Allegany	Almond, Town of	3/4/1980
Suffolk	Amityville, Village of	5/4/1998
Suffolk	Asharoken, Village of	5/4/1998
Suffolk	Babylon, Village of	5/4/1998
Suffolk	Babylon,Town of	5/4/1998
Suffolk	Belle Terre, Village of	5/4/1998
Suffolk	Bellport, Village of	5/4/1998
Suffolk	Brightwaters, Village of	5/4/1998
Suffolk	Brookhaven,Town of	5/4/1998
Suffolk	Dering Harbor, Village of	5/4/1998
Suffolk	East Hampton,Town of	5/4/1998
Suffolk	East Hampton,Village of	5/4/1998
Suffolk	Greenport, Village of	5/4/1998
Suffolk	Head of The Harbor, Village of	5/4/1998
Suffolk	Huntington Bay, Village of	5/4/1998
Suffolk	Huntington, Town of	5/4/1998
Suffolk	Islandia, Village of	5/4/1998 (X)
Suffolk	Islip,Town of	5/4/1998
Suffolk	Lake Grove, Village of	(NSFHA)
Suffolk	Lindenhurst, Village of	5/4/1998
Suffolk	Lloyd Harbor, Village of	5/4/1998
Suffolk	Nissequogue, Village of	5/4/1998
Suffolk	North Haven, Village of	5/4/1998
Suffolk	Northport, Village of	5/4/1998
Suffolk	Ocean Beach, Village of	5/4/1998

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Suffolk	Old Field, Village of	5/4/1998
Suffolk	Patchogue, Village of	5/4/1998
Suffolk	Poospatuck Indian Reservation	9/25/2009 (>)(X)
Suffolk	Poquott, Village of	5/4/1998
Suffolk	Port Jefferson, Village of	5/4/1998
Suffolk	Quogue, Village of	5/4/1998
Suffolk	Riverhead, Town of	5/4/1998
Suffolk	Sag Harbor, Village of	5/4/1998
Suffolk	Sagaponack, Village of	5/4/1998
Suffolk	Saltaire,Village of	5/4/1998
Suffolk	Shelter Island, Town of	5/4/1998
Suffolk	Shinnecock Indian Reservation	9/25/2009 (>)(X)
Suffolk	Shoreham, Village of	5/4/1998
Suffolk	Smithtown, Town of	5/4/1998
Suffolk	Southampton, Town of	5/4/1998
Suffolk	Southampton, Village of	5/4/1998
Suffolk	Southold,Town of	5/4/1998
Suffolk	The Branch, Village of	5/4/1998
Suffolk	West Hampton Dunes, Village of	5/4/1998
Suffolk	Westhampton Beach, Village of	5/4/1998
Sullivan	Bethel, Town of	2/27/1984 (M)
Sullivan	Bloomingburg, Village of	4/17/1985
Sullivan	Callicoon, Town of	3/23/1984 (M)
Sullivan	Cochecton, Town of	8/19/1987
Sullivan	Delaware, Town of	1/16/1987
Sullivan	Fallsburg, Town of	3/9/1984 (M)
Sullivan	Forestburgh, Town of	(NSFHA)
Sullivan	Fremont, Town of	4/3/1987
Sullivan	Highland, Town of	3/4/1987
Sullivan	Jeffersonville, Village of	7/16/1990
Sullivan	Liberty, Town of	6/5/1985
Sullivan	Liberty, Village of	2/1/1985
Sullivan	Lumberland, Town of	10/19/2001
Sullivan	Mamakating, Town of	9/30/1992
Sullivan	Monticello, Village of	(NSFHA)
Sullivan	Neversink, Town of	5/25/1984 (M)
Sullivan	Rockland, Town of	6/2/1993
Sullivan	Thompson, Town of	2/15/1991
Sullivan	Tusten, Town of	8/20/2002
Sullivan	Woodridge, Village of	6/25/1976 (M)
Sullivan	Wurtsboro, Village of	2/3/1993
Tioga	Barton, Town of	5/15/1991
Tioga	Berkshire, Town of	5/15/1985 (M)
Tioga	Candor, Town of	8/19/1986
Tioga	Candor, Village of	10/1/1991 (L)
Tioga	Newark Valley, Town of	2/3/1982
Tioga	Newark Valley, Village of	2/3/1982
Tioga	Nichols, Town of	2/17/1982
Tioga	Nichols, Village of	9/29/1986 (S)
Tioga	Owego, Town of	1/17/1997
Tioga	Owego, Village of	4/2/1982

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Tioga	Richford, Town of	5/15/1985 (M)
Tioga	Spencer, Town of	5/15/1985 (M)
Tioga	Spencer, Village of	5/15/1985 (M)
Tioga	Tioga, Town of	5/17/1982
Tioga	Waverly, Village of	3/16/1983
Tompkins	Caroline, Town of	6/19/1985 (M)
Tompkins	Cayuga Heights, Village of	(NSFHA)
Tompkins	Danby, Town of	5/15/1985 (M)
Tompkins	Dryden, Town of	5/15/1985 (M)
Tompkins	Dryden, Village of	1/3/1979
Tompkins	Freeville, Village of	5/1/1988 (L)
Tompkins	Groton, Town of	10/5/1984 (M)
Tompkins	Groton, Village of	11/5/1986
Tompkins	Ithaca, City of	9/30/1981
Tompkins	Ithaca, Town of	6/19/1985
Tompkins	Lansing, Town of	10/15/1985
Tompkins	Lansing, Village of	11/19/1987
Tompkins	Newfield, Town of	10/15/1985 (M)
Tompkins	Trumansburg, Village of	4/1/1988 (L)
Tompkins	Ulysses, Town of	2/19/1987
Ulster	Denning, Town of	5/25/1984 (M)
Ulster	Ellenville, Village of	7/5/1983
Ulster	Esopus, Town of	7/5/1984
Ulster	Gardiner, Town of	7/16/1997
Ulster	Hardenburgh, Town of	3/16/1989
Ulster	Hurley, Town of	8/18/1992
Ulster	Kingston, City of	5/1/1985
Ulster	Kingston,Town of	4/5/1988
Ulster	Lloyd, Town of	7/5/2000
Ulster	Marbletown, Town of	8/5/1991
Ulster	Marlborough, Town of	12/5/1984
Ulster	New Paltz, Town of	11/1/1985
Ulster	New Paltz, Village of	10/15/1985
Ulster	Olive, Town of	11/1/1984
Ulster	Plattekill, Town of	(NSFHA)
Ulster	Rochester, Town of	2/6/1991
Ulster	Rosendale, Town of	11/1/1985
Ulster	Saugerties, Town of	9/30/1992
Ulster	Saugerties, Village of	8/5/1985 (M)
Ulster	Shandaken, Town of	2/17/1989
Ulster	Shawangunk, Town of	9/30/1982
Ulster	Ulster, Town of	5/1/1985
Ulster	Wawarsing, Town of	9/15/1983
Ulster	Woodstock, Town of	9/27/1991
Warren	Bolton, Town of	8/16/1996
Warren	Chester, Town of	6/5/1985 (M)
Warren	Glens Falls, City of	6/5/1985
Warren	Hague, Town of	9/29/1996
Warren	Horicon, Town of	2/15/1985 (M)
Warren	Johnsburg, Town of	5/1/1985 (M)
Warren	Lake George, Town of	8/16/1996

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Warren	Lake George, Village of	9/29/1996
Warren	Lake Luzerne, Town of	5/1/1984
Warren	Queensbury, Town of	8/16/1996
Warren	Stony Creek, Town of	8/24/1984 (M)
Warren	Thurman, Town of	8/19/1986
Warren	Warrensburg, Town of	3/1/1984
Washington	Argyle, Town of	8/24/1979 (M)
Washington	Argyle, Village of	5/18/1979 (M)
Washington	Cambridge, Town of	9/4/1985 (M)
Washington	Cambridge, Village of	1/2/2008
Washington	Dresden, Town of	9/20/1996
Washington	Easton, Town of	11/20/1991
Washington	Fort Ann, Town of	11/5/1997
Washington	Fort Ann, Village of	(NSFHA)
Washington	Fort Edward, Town of	12/15/1982
Washington	Fort Edward, Village of	2/15/1984
Washington	Granville, Town of	8/5/1985 (M)
Washington	Granville, Village of	4/17/1985 (M)
Washington	Greenwich, Village of	5/4/2000
Washington	Greenwich,Town of	3/16/1992
Washington	Hampton, Town of	4/17/1985 (M)
Washington	Hartford, Town of	11/1/1985 (M)
Washington	Hebron, Town of	6/15/1994
Washington	Hudson Falls, Village of	(NSFHA)
Washington	Jackson, Town of	3/16/1992
Washington	Kingsbury, Town of	9/7/1979 (M)
Washington	Putnam, Town of	11/20/1996
Washington	Salem, Village of	4/17/1985 (M)
Washington	Salem,Town of	4/17/1985 (M)
Washington	White Creek, Town of	4/17/1985 (M)
Washington	Whitehall, Town of	7/3/1986
Washington	Whitehall, Village of	6/3/1985 (M)
Wayne	Arcadia, Town of	11/2/1977
Wayne	Butler, Town of	7/9/1982 (M)
Wayne	Clyde, Village of	12/18/1984
Wayne	Galen, Town of	5/16/1983
Wayne	Huron, Town of	1/19/1996
Wayne	Lyons, Town of	9/7/1979 (M)
Wayne	Lyons, Village of	3/16/1983
Wayne	Macedon, Town of	1/5/1984
Wayne	Macedon, Village of	9/30/1983
Wayne	Marion, Town of	7/1/1988 (L)
Wayne	Newark, Village of	7/15/1988
Wayne	Ontario, Town of	6/1/1978
Wayne	Palmyra, Town of	3/1/1978
Wayne	Palmyra, Village of	7/15/1988
Wayne	Red Creek, Village of	4/8/1983 (M)
Wayne	Rose, Town of	3/9/1984 (M)
Wayne	Savannah, Town of	8/6/1982 (M)
Wayne	Sodus Point, Village of	11/2/1977
Wayne	Sodus, Town of	6/2/1992

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Wayne	Walworth, Town of	3/16/1983
Wayne	Williamson Town	10/17/1978
Wayne	Wolcott, Town of	6/2/1992
Wayne	Wolcott, Village of	7/6/1984 (M)
Westchester	Ardsley, Village of	9/28/2007
Westchester	Bedford, Town of	9/28/2007
Westchester	Briarcliff Manor, Village of	9/28/2007
Westchester	Bronxville, Village of	9/28/2007
Westchester	Buchanan, Village of	9/28/2007 (M)
Westchester	Cortlandt, Town of	9/28/2007
Westchester	Croton-On-Hudson, Village of	9/28/2007
Westchester	Dobbs Ferry, Village of	9/28/2007
Westchester	Eastchester, Town of	9/28/2007
Westchester	Elmsford, Village of	9/28/2007
Westchester	Greenburgh,Town of	9/28/2007
Westchester	Harrison, Town of	9/28/2007
Westchester	Hastings-On-Hudson, Village of	9/28/2007
Westchester	Irvington, Village of	9/28/2007
Westchester	Larchmont, Village of	9/28/2007
Westchester	Lewisboro, Town of	9/28/2007 (M)
Westchester	Mamaroneck, Town of	9/28/2007
Westchester	Mamaroneck, Village of	9/28/2007
Westchester	Mount Kisco, Village of	9/28/2007
Westchester	Mount Pleasant, Town of	9/28/2007
Westchester	Mount Vernon, City of	9/28/2007
Westchester	New Castle, Town of	9/28/2007
Westchester	New Rochelle, City of	9/28/2007
Westchester	North Castle, Town of	9/28/2007
Westchester	North Salem, Town of	9/28/2007
Westchester	Ossining, Town of	9/28/2007
Westchester	Ossining, Village of	9/28/2007
Westchester	Peekskill, City of	9/28/2007
Westchester	Pelham Manor, Village of	9/28/2007
Westchester	Pelham, Village of	9/28/2007
Westchester	Pleasantville, Village of	9/28/2007
Westchester	Port Chester, Village of	9/28/2007
Westchester	Pound Ridge, Town of	9/28/2007
Westchester	Rye Brook, Village of	9/28/2007
Westchester	Rye, City of	9/28/2007
Westchester	Scarsdale, Village of	9/28/2007
Westchester	Sleepy Hollow, Village of	9/28/2007
Westchester	Somers, Town of	9/28/2007
Westchester	Tarrytown, Village of	9/28/2007
Westchester	Tuckahoe, Village of	9/28/2007
Westchester	White Plains, City of	9/28/2007
Westchester	Yonkers, City of	9/28/2007
Westchester	Yorktown, Town of	9/28/2007
Wyoming	Arcade, Town of	3/3/1992
Wyoming	Arcade, Village of	3/3/1992
Wyoming	Attica, Town of	4/30/1986
Wyoming	Bennington, Town of	12/23/1983 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
Wyoming	Castile, Town of	12/23/1983 (M)
Wyoming	Castile, Village of	5/28/1982 (M)
Wyoming	Covington, Town of	12/23/1983 (M)
Wyoming	Eagle, Town of	12/23/1983 (M)
Wyoming	Gainesville, Town of	12/23/1983 (M)
Wyoming	Gainesville, Village of	2/15/1985 (M)
Wyoming	Genesee Falls, Town of	5/1/1984
Wyoming	Java, Town of	12/23/1983 (M)
Wyoming	Orangeville, Town of	12/23/1983 (M)
Wyoming	Perry, Town of	12/23/1983 (M)
Wyoming	Perry, Village of	7/29/1977 (M)
Wyoming	Pike, Town of	12/23/1983 (M)
Wyoming	Pike, Village of	6/18/1982 (M)
Wyoming	Sheldon, Town of	12/23/1983 (M)
Wyoming	Silver Springs, Village of	1/20/1984 (M)
Wyoming	Warsaw, Town of	12/23/1983 (M)
Wyoming	Warsaw, Village of	11/18/1981
Wyoming	Wethersfield, Town of	7/16/1982 (S)
Wyoming	Wyoming, Village of	8/3/1981
Yates	Barrington, Town of	3/9/1984 (M)
Yates	Benton, Town of	1/20/1984 (M)
Yates	Dresden, Village of	6/15/1981
Yates	Dundee, Village of	3/1/1988 (L)
Yates	Italy, Town of	3/7/2001
Yates	Jerusalem, Town of	1/20/1984 (M)
Yates	Middlesex, Town of	9/29/1989
Yates	Milo, Town of	7/18/1985 (M)
Yates	Penn Yan, Village of	6/15/1981
Yates	Potter, Town of	3/23/1984 (M)
Yates	Rushville, Village of	6/5/1985 (M)
Yates	Starkey, Town of	12/3/1987
Yates	Torrey, Town of	12/3/1987

Notes:
(NSFHA) - No special flood hazard area - All Zone "C"
(M) No elevation determined - All Zone "A", "C", and "X"
(L) Original FIRM by letter - All Zone "A", "C", and "X"
(S) Suspended community, not in the National Flood Program.
(X) Community not in National Flood Program
(>) Date of current effective map is after the date of this report.
Source: FEMA "Community Status Book Report – July 23, 2009."
(http://www.fema.gov/fema/csb.shtm)

New York State

DEC

Division of Mineral Resources

Appendix 2

1992 SEQRA Findings Statement On the GEIS on the Oil, Gas and Solution Mining Regulatory Program

Draft Supplemental Generic Environmental Impact Statement

September 1, 1992

Findings Statement

Pursuant to the State Environmental Quality Review Act (SEQR) of the Environmental Conservation Law (ECL) and the SEQR Regulations 6NYCRR Part 617, the New York State Department of Environmental Conservation makes the following findings.

Name of Action

Adoption of the Final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.

Description and Background

In early 1988, the Department of Environmental Conservation released the Draft GEIS on the Oil, Gas and Solution Mining Regulatory Program. The Draft GEIS comprehensively reviewed the environmental impacts of the Department's program for regulating the siting, drilling, production and plugging and abandonment of oil, gas, underground gas storage, solution mining, brine disposal, geothermal and stratigraphic test wells. Six public hearings were held on the Draft GEIS in June 1988.

The Final GEIS was released in July 1992. It contains individual responses to the hundreds of comments received on the Draft GEIS. The Final GEIS also includes more detailed topical responses addressing several controversial issues that frequently appeared in the comments on the draft document.

Together, the Draft and Final GEIS and this Findings Statement will provide the groundwork for revisions to the Oil, Gas and Solution Mining Regulations (6NYCRR Parts 550-559). These regulations are being updated to more accurately reflect and effectively implement the current Oil, Gas and Solution Mining Law (ECL Article 23).

The Draft GEIS included suggested changes to the regulations in bold print throughout the document. In the interests of environmental protection and public safety, a significant number of the suggested regulatory changes are already put in effect as standard conditions routinely applied to permits. All formal regulation changes, however, must be promulgated in accordance with the State Administrative Procedure Act (SAPA) requiring separate review, public hearings and approval. Further public input during the rulemaking process may cause some of the new regulations, when they are eventually adopted, to differ from those discussed in the GEIS. Any regulations adopted that differ significantly from those discussed in the GEIS will undergo an additional SEQR Review and Determination.

Location

Statewide.

DEC Jurisdiction

Jurisdiction is provided by the Oil, Gas and Solution Mining Law (ECL Article 23).

Date Final GEIS Filed

The Final GEIS was filed June 25, 1992/#PO-009900-00046. The Notice of Completion was published in the Environmental Notice Bulletin July 8, 1992.

Facts and Conclusions Relied Upon to Support the SEQR Findings

The record of facts established in the Draft and Final GEIS upholds the following conclusions:

1. The **unregulated** siting, drilling, production, and plugging and abandonment of oil, gas, solution mining, underground gas storage, brine disposal, geothermal and stratigraphic test wells could have potential negative impacts on every aspect of the environment. The potential negative impacts range from very minor to significant. Potential impacts of **unregulated** activities on ground and surface waters are a particularly serious concern. The potential negative impacts on all environmental resources are described in detail in Chapters 8 through 14 and summarized in Chapter 16 of the Draft GEIS.

2. Under **existing regulations and permit conditions**, the potential environmental impacts of the above wells are **greatly reduced** and most are reduced to non-significant levels. The extensive mitigation measures required under the existing regulatory program are described in detail in Chapters 8 through 14 and summarized in Chapter 17 of the Draft GEIS.

3. The potential environmental impacts associated with the activities covered by the Oil, Gas and Solution Mining Regulatory Program also have economic and social implications. For example, it is less expensive to prevent pollution than pay for remediation of environmental problems, health care costs, and lawsuit expenses. The State also receives significant economic benefits from the activities covered by the regulatory program. The regulated industries provide jobs and economic stimulus through the purchase of goods and services, and the payment of taxes, royalties and leasing bonuses. Additional information on the potential economic impacts associated with the activities covered by the regulatory program is provided in Chapter 18 of the Draft GEIS.

4. The Department's routine requirement of: 1) a program-specific Environmental Assessment Form (EAF) with <u>every</u> well drilling permit application, 2) a plat (map) showing the proposed well location, and 3) a pre-drilling site inspection, allows the Department to:

   - reliably determine potential environmental problems, and
   - select appropriate permit conditions for mitigating potential environmental impacts.

   The EAF is printed in its entirety and discussed in detail on pages FGEIS 30-34 of the Final GEIS. Information on the permit application review process is summarized in Chapter 7 of the Draft GEIS.

5. The majority of the industry's activity centers on drilling individual oil and gas wells for primary production. For purposes of this Findings Statement, standard oil and gas operations are defined as:

   - any procedure relevant to rotary or cable tool drilling procedures, and
   - production operations which do <u>not</u> utilize any type of artificial means to facilitate the recovery of hydrocarbons.

   The basic features of standard oil and gas operations are described in detail in Chapters 9 through 11 of the Draft GEIS.

6. The diverse types of wells covered by the regulatory program have enough design and operational characteristics in common to group them according to their potential environmental impacts. Design and operational aspects of these wells are described in detail in Chapters 9 through 14 of the Draft GEIS.

7. The magnitude of potential environmental impacts associated with any proposed well covered by the regulatory program is strongly influenced by the types of natural and cultural resources in the well's vicinity. New York State's environmental resources are described in Chapter 6 of the Draft GEIS. Most of the information on the potential environmental impacts of the regulated activities on these environmental resources can be found in Chapter 8 of the Draft GEIS, which deals with siting issues. Additional information on potential impacts related to specific stages (drilling, completion, production, plugging and abandonment) of well operation can be found in Chapters 9 through 11 of the Draft GEIS. Additional information on potential environmental impacts related specifically to enhanced oil recovery, solution salt mining, underground gas storage and waste brine disposal can be found in Chapters 12 through 15 of the Draft GEIS.

8. The range of future alternatives concerning the activities covered by the Oil, Gas and Solution Mining Regulatory Program can be divided into three basic categories: 1) prohibition on regulated activities, 2) removal of regulation, and 3) maintenance of status quo versus revision of existing regulations. A prohibition on these regulated activities would deprive the State of substantial economic and natural resource benefits. Complete removal of regulation would lead to severe environmental problems. While the existing regulations and permit conditions provide significant environmental protection, there is still room to improve the efficiency and effectiveness of the program. Revision of the existing regulations is the best alternative. Chapter 21 of the Draft GEIS contains a more detailed assessment of the environmental, economic, and social aspects of each alternative.

SEQR Determinations of Significance

The SEQR determinations on the significance of the environmental impacts associated with the activities covered by this regulatory program are presented in the following table. The determinations are supported by the conclusions listed above, which in turn are supported by the referenced sections of the Draft and Final GEIS.

SEQR DETERMINATIONS

	Agency Action	Environmental Impact	Explanation
a.	Standard individual oil, gas, solution mining, stratigraphic, geothermal, or gas storage well drilling permits (no other permits involved).	not significant	Rules and regulations and conditions are adequate to protect the environment. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.
b.	Oil and gas drilling permits in State Parklands.	may be significant	Site-specific conditions of State Parklands are not discussed in the Draft and Final GEIS. Further determination of significant environmental impacts is needed for State Parklands. A site-specific EAF is required with the permit application.
c.	Oil and gas drilling permits in Agricultural Districts.	may be significant	Rules and regulations and conditions are adequate to protect the environment. For most oil and gas operations in Agricultural Districts which utilize less than 2½ acres the GEIS satisfies SEQR. If more than 2½ acres are disturbed, this is a Type I action under 6NYCRR Part 617 and an additional determination of significance is required. A site-specific EAF is required with the permit application.
d.	Oil and gas drilling permits in the "Bass Island" fields.	not significant	Special conditions and regulations under Part 559 are adequate to protect the environment. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.

e. Oil and gas drilling permits for locations above aquifers.	not significant	Rules and regulations and special aquifer conditions employed by DEC have been developed specifically to protect the groundwater resources of the State. The Draft and Final GEIS satisfy SEQR for these actions. A site-specific EAF is required with the permit application.
f. Oil and gas drilling permits in close proximity (less than 1,000 feet) to municipal water supply wells.	always significant	A supplemental EIS is required dealing with the groundwater hydrology, potential impacts and mitigation measures. A site-specific EAF is required with the permit application.
g. Oil and gas drilling permits in proximity (between 1,000 and 2,000 feet) to municipal water supply wells.	may be significant	A supplemental EIS may be required dealing with the groundwater hydrology, potential impacts and mitigation measures. A site-specific assessment and SEQR determination are required. A site-specific EAF is required with the permit application.
h. Oil and gas drilling permits when other DEC permits required.	may be significant	A site-specific SEQR assessment and determination are needed based on the environmental conditions requiring additional DEC permits. A site-specific EAF is required with the permit application.
i. Plugging permits for oil, gas, solution mining, stratigraphic, geothermal, gas storage and brine disposal wells.	Type II *	By law all wells drilled must be plugged before abandonment. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action.

* Under 6NYCRR 617.13, a Type II action is one which has been determined not to have a significant effect on the environment and does not require any other SEQR determination or procedure.

j.	New waterflood or tertiary recovery projects.	may be significant	For major new waterfloods and new tertiary recovery projects, a site specific environmental assessment and SEQR determination are required. A supplemental EIS may be required for new waterfloods to ensure integrity of the flood. Also, a supplemental EIS may be required for new tertiary recovery projects depending on the scope of operations and methods used. A site-specific EAF is required with the permit application.
k.	New underground gas storage projects or major modifications.	may be significant	A site-specific environmental assessment and SEQR determination are required. May require a supplemental EIS depending on the scope of the project. A site-specific EAF is required with the permit application.
l.	New solution mining projects or major modifications.	may be significant	A site-specific environmental assessment and SEQR determination are required. May require a supplemental EIS depending on the scope of the project. A site-specific EAF is required with the permit application.
m.	Spacing hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.
n.	Variance hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.

o. Compulsory unitization hearing.	not significant	Action to hold hearing is non-significant. A review and SEQR determination with respect to all other issues must be made before the hearing. Any permit issued subsequently will be reviewed on issues raised at hearing. A site-specific EAF is required with the permit application.
p. Natural Gas Policy Act pricing recommendations.	none	Action only results in recommendations to Federal Energy Regulatory Commission; therefore, action is not subject to SEQR.
q. Brine disposal well drilling or conversion permit.	may be significant	The brine disposal well permitting guidelines require an extensive surface and subsurface evaluation which is in effect a supplemental EIS addressing technical issues. An additional site specific environmental assessment and SEQR determination are required. A site-specific EAF is required with the permit application.

SEQR Review Procedures

Upon filing of this Findings Statement, the following SEQR Review procedures will be adopted for the Oil, Gas and Solution Mining Regulatory Program:

1. A shortened program-specific Environmental Assessment Form (EAF) will continue to be required with every well drilling permit application, regardless of the SEQR determination listed in the previous table. Information required by the EAF is considered to be an essential part of the permit application. It contains vital site-specific information necessary to evaluate the need for individual permit conditions.

2. In the following cases where the GEIS satisfies SEQR, Department staff will no longer make Determinations of Significance and a Negative or Positive Declaration under SEQR will no longer be required so long as projects conform to the descriptions in the Draft and Final GEIS:
   - Standard individual oil, gas, solution mining, stratigraphic test, geothermal or gas storage well drilling permits,
   - Oil and gas drilling permits in the "Bass Islands" field, and
   - Oil and gas drilling permits for locations above aquifers.

3. In addition to the short program-specific EAF, permits for the following projects will also require detailed site-specific environmental assessments using the Long-Form EAF published in Appendix A of 6NYCRR Part 617. A site or project-specific EIS may also be required for the following projects depending upon the information revealed in the permit application and accompanying EAF's:
   - Oil and gas drilling permits in Agricultural Districts if more than two and one-half acres will be altered by construction of the well site and access road.
   - Oil and gas drilling permits in State Parklands.
   - Oil and gas drilling permits when other DEC permits are required.

- Oil and gas drilling permits less than 2,000 feet from a municipal water supply well.
- New major waterflood or tertiary recovery projects.
- New underground gas storage projects or major modifications.
- New solution mining projects or major modifications.
- Brine disposal well drilling or conversion permits.
- Any other project not conforming to the standards, criteria or thresholds required by the Draft and Final GEIS.

Other SEQR Considerations

In conducting SEQR reviews, the Department will handle the topics of individual project scope, project size, lead agency, and coastal resources as described below.

1. Project scope - Each application to drill a well will continue to be considered as an individual project. An applicant applying for five wells will continue to be treated the same as five applicants applying to the Department individually, since the wells may not be drilled at the same time or in the same area. Planned future wells might not be drilled at all depending on the results of the first well drilled.

   The exceptions to this are proposed new or major expansions of solution mining, enhanced recovery or underground gas storage operations which require that several wells be drilled and operated for an extended period of time within a limited area.

2. Size of Project - The size of the project will continue to be defined as the surface acreage affected by development.

3. Lead Agency - In 1981, the Legislature gave exclusive authority to the Department to regulate the oil, gas and solution mining industries under ECL Section 23-0303(2). Thus, only the Department has jurisdiction to grant drilling permits for wells subject to Article 23, except within State parklands. To the extent practicable, the Department will actively seek lead agency designation consistent

with the general intent of Chapter 846 of the Laws of 1981.

4. Coastal Resources - On the program specific EAF that must accompany every drilling permit application, the applicant must indicate whether the proposed well is in a legally designated New York State Coastal Zone Management (CZM) Area. Neither the policies in the New York State CZM Plan, nor the provisions of individual Local Waterfront Revitalization Plans (LWRP's) are covered in the GEIS. Once an LWRP is adopted by a community, it is a legally binding part of the New York State CZM Plan. The Department cannot issue any drilling permit unless it is consistent with the New York State CZM Plan to the "maximum extent practicable."

CERTIFICATION OF FINDINGS TO ADOPT THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met;

2. Consistent with the social, economic and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement, and

3. Consistent with social, economic and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

Gregory H. Sovas — Sept. 29, 1992

Director — Date
Division of Mineral Resources

New York State

DEC

Division of Mineral Resources

Appendix 3

Supplemental SEQRA Findings Statement on Leasing of State Lands for Activities Regulated Under the Oil, Gas and Solution Mining Law

Draft Supplemental Generic Environmental Impact Statement

SEQR File No.

P0-009900-00046

Supplemental
Findings Statement

Pursuant to the State Environmental Quality Review Act (SEQR) of the Environmental Conservation Law (ECL) and the SEQR Regulations 6NYCRR Part 617, the New York State Department of Environmental Conservation makes the following supplemental findings on the Final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.

Name of Action

Adoption of supplemental findings on leasing of state lands for activities regulated under the Oil, Gas and Solution Mining Law (ECL Article 23).

Description and Background

In early 1988, the Department of Environmental Conservation released the Draft GEIS on the Oil, Gas and Solution Mining Regulatory Program. The Draft GEIS comprehensively reviewed the environmental impacts of the Department's program for regulating the siting, drilling, production and plugging and abandonment of oil, gas, underground gas storage, solution mining, brine disposal, geothermal and stratigraphic test wells. The findings statement issued on the Draft and Final GEIS in September, 1992 neglected to specifically mention DEC's program for leasing of State lands for these resource development activities.

Prior to adoption of the GEIS, proposed lease sales underwent a segmented review. Segmented reviews are permitted under certain circumstances if they are no less protective of the environment. This is true given the highly speculative nature of oil and gas leasing practices:

- It is impractical to review the potential environmental impacts of development activities at the leasing stage. Information on the placement of well sites is not generally known, even by the lessee. Not until a company successfully obtains a lease does it invest time and money in preparing the exploration and development plans that will be submitted to the Department for approval if the lessee wishes to commence operations.

- Most of the land leased will never be directly affected by development activities. Based on a 15 year record of the State's leasing program, less than one percent of all the State land leased has been subject to any direct impact.

- When the lessee does decide on a proposed well site on a State lease, the lessee must obtain a site-specific drilling permit from the Department. With eve well drilling permit application the Department requires: 1) a program-specific Environmental Assessment Form, 2) a plat (map) showing the proposed well location and support facilities, and 3) a pre-drilling site inspection that allows the Department to :
    - reliably determine potential environmental problems; and

- select appropriate permit conditions for mitigating potential environmental impacts.

- Possession of a lease does not a priori grant the right to drill on a lease. Nor is the lessee in any way guaranteed approval for their first-choice drilling location. Clauses included in the lease inform the lessee that any surface disturbing activities must receive Department review and approval prior. to their commencement. Leases also contain clauses recommended by other State agency staff that are necessary for protection of fish, wildlife, plant, land, air, wetlands, water and cultural resources on the leased parcels.

SEOR Determination of Significance

The Department has determined that the act of leasing State lands for activities regulated under ECL Article 23 does not have a significant environmental impact. This determination is supported by the facts listed above.

SEOR Review Procedures

Department staff will no longer make Determinations of Significance and Negative or Positive Declarations under SEQR for leases on State lands for activities regulated under ECL Article 23 at the time that the lease is granted; SEQR reviews will continue to be done as needed for site-specific development.

CERTIFICATION OF SUPPLEMENTAL FINDINGS ON THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Supplemental Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met.

2. Consistent with the social, economic, and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement.

3. Consistent with the social, economic, and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

/S/ April 19, 1993

Gregory H. Sovas, Director
Division of Mineral Resources

New York State

DEC

Division of Mineral Resources

Appendix 4

Application Form for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Regulatory Program

Draft Supplemental Generic Environmental Impact Statement

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES • BUREAU OF OIL AND GAS REGULATION

PRINT OR TYPE IN BLACK INK

APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT A WELL SUBJECT TO THE OIL, GAS AND SOLUTION MINING LAW

THIS APPLICATION IS A LEGAL DOCUMENT. READ THE APPLICABLE AFFIRMATION AND ACKNOWLEDGMENT CAREFULLY BEFORE SIGNING.
For instructions on completing this form, visit the Division's website at www.dec.ny.gov/energy/205.html or contact your local Regional office.

PLANNED OPERATION: (Check one)
☐ Drill ☐ Deepen ☐ Plug Back ☐ Convert

TYPE OF WELL: (Check one)
☐ New ☐ Existing

Existing API Well Identification Number
31- | | | - | | | | | - | | | - | | |

TYPE OF WELL BORE: (Check one)
☐ Vertical ☐ Directional Sidetrack

NAME OF OWNER (Full Name of Organization or Individual as registered with the Division)	TELEPHONE NUMBER (include area code)
ADDRESS (P.O. Box or Street Address, City, State, Zip Code)	
NAME AND TITLE OF LOCAL REPRESENTATIVE WHO CAN BE CONTACTED WHILE OPERATIONS ARE IN PROGRESS	
ADDRESS–Business (P.O. Box or Street Address, City, State, Zip Code)	TELEPHONE NUMBER (include area code)
ADDRESS–Night, Weekend and Holiday (P.O. Box or Street Address, City, State, Zip Code)	TELEPHONE NUMBER (include area code)

WELL LOCATION DATA (attach plat)

COUNTY	TOWN	FIELD/POOL NAME (or "Wildcat")

WELL NAME	WELL NUMBER	NUMBER OF ACRES IN UNIT

7½ MINUTE QUAD NAME	QUAD SECTION	PROPOSED TARGET FORMATION

LOCATION DESCRIPTION

	TVD	TMD	Decimal Latitude (NAD83)	Decimal Longitude (NAD83)
Surface	0'	0'	__ __ . __ __ __ __ __ __	__ __ . __ __ __ __ __ __
Top of Target Interval			__ __ . __ __ __ __ __ __	__ __ . __ __ __ __ __ __
Bottom of Target Interval			__ __ . __ __ __ __ __ __	__ __ . __ __ __ __ __ __
Bottom Hole			__ __ . __ __ __ __ __ __	__ __ . __ __ __ __ __ __

PROPOSED WELL DATA

WELL TYPE (check one)
☐ Oil Production ☐ Gas Production ☐ Brine ☐ Storage
☐ Injection ☐ Brine Disposal ☐ Geothermal ☐ Stratigraphic
☐ Other ____________

PLANNED TOTAL DEPTH
TVD ________ ft.
TMD ________ ft.
Kickoff ________ TMD

PLANNED DATE OF COMMENCEMENT OF OPERATIONS

SURFACE ELEVATION (check how obtained)
________ ft. ☐ Surveyed ☐ Topo Map ☐ Other ________

TYPE OF TOOLS
☐ Cable ☐ Rotary

PLANNED DRILLING FLUID
☐ Air ☐ Water ☐ Mud

NAME OF PLANNED DRILLING CONTRACTOR (as registered with the Division)	TELEPHONE NUMBER (include area code)

ON ATTACHED SHEET GIVE DETAILS FOR EACH PROPOSED CASING STRING AND CEMENT JOB INCLUDING BUT NOT LIMITED TO: Bit size, casing size, casing weight and grade, TVD and TMD of casing set, scratchers, centralizers, cement baskets, sacks of cement, class of cement, cement additives with percentages or pounds per sack, estimated TVD and TMD of the top of cement, estimated amount of excess cement and waiting-on-cement time.

FOR DIRECTIONAL OR SIDETRACK WELLS ALSO INCLUDE A WELL BORE DIAGRAM SHOWING THE LOCATION OF THE ITEMS INCLUDED IN THE ABOVE REFERENCED DETAILS.

DEPARTMENT USE ONLY

BOND NUMBER

API WELL IDENTIFICATION NUMBER
31-

RECEIPT NUMBER

DATE ISSUED

APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT

WELL NAME	WELL NUMBER	NAME OF OWNER

COMMENTS:

AFFIRMATION AND ACKNOWLEDGMENT

A. For use by individual:

By the act of signing this application:

(1) I affirm under penalty that the information provided in this application is true to the best of my knowledge and belief; and that I possess the right to access property, and drill and/or extract oil, gas, or salt, by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) I acknowledge that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, I accept full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agree to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

____
Printed or Typed Name of Individual

______________________________ ______________
Signature of Individual Date

B. For use by organizations other than an individual:

By the act of signing this application:

(1) I affirm under penalty of perjury that I am ______________________________ (title) of ______________________________ (organization); that I am authorized by organization to make this application; that this application was prepared by me or under my supervision and direction; and that the aforenamed organization possesses the right to access property, and drill and/or extract oil, gas, or salt by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) ______________________________ (organization); acknowledges that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, it accepts full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agrees to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, from suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

____
Printed or Typed Name of Authorized Representative

______________________________ ______________
Signature of Authorized Representative Date

New York State

DEC

Division of Mineral Resources

Appendix 5

Environmental Assessment Form
For Well Permitting

Draft Supplemental Generic Environmental Impact Statement

85-16-5 (1/07)--10b

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

ENVIRONMENTAL ASSESSMENT FORM

Attachment to Drilling Permit Application

WELL NAME AND NUMBER			
NAME OF APPLICANT	BUSINESS TELEPHONE NUMBER ( )		
ADDRESS OF APPLICANT			
CITY/P.O.		STATE	ZIP CODE

DESCRIPTION OF PROJECT (Briefly describe type of project or action)

PROJECT SITE IS THE WELL SITE AND SURROUNDING AREA WHICH WILL BE DISTURBED DURING CONSTRUCTION OF SITE, ACCESS ROAD, and PIT AND ACTIVITIES DURING DRILLING AND COMPLETION AT WELLHEAD.
(PLEASE COMPLETE EACH QUESTION--Indicate N.A., if not applicable)

LAND USE AND PROJECT SITE

1. Project Dimensions. Total Area of Project Site ________ sq. ft.
   Approximate square footage for items below:

		During Construction (sq. ft.)	After Construction (sq. ft.)
a. Access Road	(length x width)	________	________
b. Well Site	(length x width)	________	________

2. Characterize Project Site Vegetation and Estimate Percentage of Each Type Before Construction:

   ______ % Agricultural (cropland, hayland, pasture, vineyard, etc.) ______ % Forested ______ % Wetlands

   ______ % Meadow or Brushland (non agricultural) ______ % Non vegetated (rock, soil, fill)

3. Present Land Use(s) Within ¼ Mile of Project (Check all that apply)
   ☐ Rural ☐ Suburban ☐ Forest ☐ Urban ☐ Agricultural ☐ Commercial ☐ Park/Recreation
   ☐ Industrial ☐ Other ________

4. How close is the nearest residence, building, or outdoor facility of any type routinely occupied by people at least part of the day? ________ ft.
   Describe ________

ENVIRONMENTAL RESOURCES ON/NEAR PROJECT SITE

5. The presence of certain environmental resources on or near the project site may require additional permits, approvals or mitigation measures--Is any part of the well site or access road located:

a. Over a primary or principal aquifer?	☐ Yes	☐ No	☐ Not Known
b. Within 2,640 feet of a public water supply well?	☐ Yes	☐ No	☐ Not Known
c. Within 150 feet of a surface municipal water supply?	☐ Yes	☐ No	☐ Not Known
d. Within 150 feet of a lake, stream, or other public surface water body?	☐ Yes	☐ No	☐ Not Known
e. Within an Agricultural District?	☐ Yes	☐ No	☐ Not Known
f. Within a land parcel having a Soil and Water Conservation Plan?	☐ Yes	☐ No	☐ Not Known
g. In a 100 year flood plain?	☐ Yes	☐ No	☐ Not Known
h. In a regulated wetland or its 100 foot buffer zone?	☐ Yes	☐ No	☐ Not Known
i. In a coastal zone management area?	☐ Yes	☐ No	☐ Not Known
j. In a Critical Environmental Area?	☐ Yes	☐ No	☐ Not Known
k. Does the project site contain any species of animal life that are listed as threatened or endangered?	☐ Yes	☐ No	☐ Not Known

   If yes, identify the species and source of information ________

l. Will proposed project significantly impact visual resources of statewide significance?	☐ Yes	☐ No	☐ Not Known

   If yes, identify the visual resource and source of information ________

CULTURAL RESOURCES

6. Are there any known archeological and/or historical resources which will be affected by drilling operations? ☐ Yes ☐ No ☐ Not Known

7. Has the land within the project area been previously disturbed or altered (excavated, landscaped, filled, utilities installed)? ☐ Yes ☐ No ☐ Not Known

   If answer to Number 6 or 7 is yes, briefly descrbe ______________________________

   ____

EROSION AND RECLAMATION PLANS

8. Indicate percentage of project site within: 0-10% slope ______ % 10-15% slope ______ % greater than 15% slope ______ %

9. Are erosion control measures needed during construction of the access road and well site? ☐ Yes ☐ No ☐ Not Known

   If yes, describe and/or sketch on attached photocopy of plat ______________________________

   ____

   ____

10. Will the topsoil which is disturbed be stockpiled for reclamation use? ☐ Yes ☐ No

11. Does the reclamation plan include revegetation? ☐ Yes ☐ No

    If yes, what plant materials will be used? ______________________________

    ____

12. Does the reclamation plan include restoration or installation of surface or subsurface drainage features to prevent erosion or conform to a Soil and Water Conservation Plan? ☐ Yes ☐ No

    If yes, describe ______________________________

    ____

ACCESS ROAD SITING AND CONSTRUCTION

13. Are you going to use existing or common corridors when building the access road? ☐ Yes ☐ No

    Locate access road on attached photocopy of plat.

DRILLING

14. Anticipated length of drilling operations? ________ days.

WASTE STORAGE AND DISPOSAL

15. How will drilling fluids and stimulation fluids:

    a. Be contained? ______________________________

    b. Be disposed of? ______________________________

16. Will production brine be stored on site? ☐ Yes ☐ No

    If yes:
    How will it be stored? ______________________________

    How will it be disposed of? ______________________________

17. Will the drill cuttings and pit liner be disposed of on site? ☐ Yes ☐ No

    If yes, expected burial depth? ______________ feet

ADDITIONAL PERMITS

18. Are any additional State, Local or Federal permits or approvals required for this project? ☐ Yes ☐ No

	Date Application Submitted	Date Application Received
Stream Disturbance Permit (DEC)	__|__|__	__|__|__
Wetlands Permit (DEC or Local)	__|__|__	__|__|__
Floodplain Permit (DEC or Local)	__|__|__	__|__|__
Other ______________________________	__|__|__	__|__|__
______________________________	__|__|__	__|__|__
______________________________	__|__|__	__|__|__
______________________________	__|__|__	__|__|__

PREPARER'S SIGNATURE	DATE
NAME/TITLE (Please print)	
REPRESENTING	

Suggested Sources of Information for Division of Mineral Resources Environmental Assessment Form

3. LAND USE
Sources: Local Planning Office
Town Supervisor's Office
Town Clerk's Office

5a. PRIMARY OR PRINCIPAL AQUIFER
Sources: Local unit of government
NYS Department of Health
NYSDEC, Division of Water--Regional Office
Availability of Water from Aquifers in New York State--United States Geological Survey
Availability of Water from Unconsolidated Deposits in Upstate New York--United States Geological Survey

5b. PUBLIC WATER SUPPLY
Sources: Local unit of government
NYS Department of Health
NYS Atlas of Community Water Systems Sources, NYS Department of Health, 1982
Atlas of Eleven Selected Aquifers in New York State, United States Geological Survey, 1982

5c. AGRICULTURAL DISTRICT INFORMATION
Sources: Cooperative Extension
DEC, Division of Lands and Forests
NYS Department of Agriculture and Markets
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5f. SOIL AND WATER CONSERVATION PLAN
Sources: Landowner
County Soil and Water Conservation District Office

5g. 100 YEAR FLOOD PLAIN
Sources: DEC Division of Water
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5h. WETLANDS
Sources: DEC, Division of Fish and Wildlife--Regional Office
DEC, Division of Mineral Resources--Regional Office

5i. COASTAL ZONE MANAGEMENT AREAS
Sources: Local unit of government
NYS Department of State, Coastal Management Program
DEC, Division of Water (maps)
DEC, Division of Environmental Permits--Regional Office

5k. THREATENED OR ENDANGERED SPECIES
Sources: DEC, Natural Heritage Program--Albany
DEC, Division of Environmental Permits--Regional Office

6. ARCHEOLOGICAL OR HISTORIC RESOURCES
Sources: NYS Office of Parks, Recreation and Historic Preservation circles and squares map
DEC, Division of Environmental Permits--Regional Office

18. ADDITIONAL PERMITS NEEDED
Sources: DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office
NYS Office of Business Permits

New York State

DEC

Division of Mineral Resources

Appendix 6

PROPOSED
Environmental Assessment Form
(EAF) Addendum

Draft Supplemental Generic Environmental Impact Statement

REQUIRED INFORMATION

- Minimum depth and elevation of top of fracture zone for entire length of wellbore
- Estimated maximum depth and elevation of bottom of potential fresh water, and basis for estimate (water well information, other well information, previous drilling at pad, published or private reports, etc.)
- Identification of proposed fracturing service company and additive products
- Proposed volume of fracturing fluid and % by weight of water, proppants and each additive
- Water source for hydraulic fracturing
    - If a newly proposed surface water source (not previously approved by DEC as part of a well permit application):
        - Location of water withdrawal point, status of RBC approval if applicable
        - Indicate if an Article 15 permit is required and status
        - Size of drainage area above withdrawal point (in mi^2)
        - Indicate whether there is a USGS gauge on the stream; if yes:
            - Distance to stream gauge
            - Upstream or downstream of stream gauge
            - Changes in stream flow (e.g., other withdrawals, diversions, tributary input) between gauge and withdrawal point
            - Years of stream gauge data available and period of record
    - If a previously proposed or DEC-approved surface water source:
        - API # of well permit application associated with previous proposal or approval
- Distance from surface location of well to:
    - Any known water well or domestic-supply spring within 2,640 feet, including public or private wells, community or non-community systems
- Distance from closest edge of well pad to:
    - Any water supply reservoir within 1,320 feet (include reservoir stem and controlled lake in NYC Watershed)
    - Any perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet (include watercourse in NYC Watershed)
    - All occupied structures or places of assembly within 1,320 feet
- Capacity of rig fuel tank(s) and distance to:
    - Any primary or principal aquifer, public or private water well, domestic-supply spring, reservoir, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned tank location (include reservoir stem, controlled lake and watercourse in NYC Watershed).
- Available information about water wells and domestic-supply springs within 2,640 feet
    - Well name and location
    - Distance from proposed surface location of well
    - Shortest distance from proposed well pad
    - Shortest distance from proposed centralized flowback water impoundment
    - Well depth
    - Well's completed interval
    - Public or private supply

    - Community or non-community system (see DOH definitions)
    - Type of facility or establishment if not a residence
- Information about the planned construction and capacity of the reserve pit
- Information about the number and individual and total capacity of receiving tanks for flowback water
- Stack heights for: drilling rig and hydraulic fracturing engines, flowback vent/flare, glycol dehydrator. If proposed flowback vent/flare stack height is less than 30 feet, then documentation that previous drilling at the pad did not encounter H_2S is required.
- Description of planned public access restrictions, including physical barriers and distance to edge of well pad
- Description of other control measures planned to reduce particulate matter emissions during the hydraulic fracturing process

REQUIRED ATTACHMENTS

- Topographic map of area within at least 2,640 feet of surface location showing:
    - above features and scaled distances
    - location and orientation of well pad
    - well pad close-up showing placement of fuel tank, reserve pit and receiving tanks for flowback water
    - location of access road
    - location of any flowback water pipelines or conveyances
    - location of any centralized flowback water impoundment proposed for use
- Evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within half a mile (2,640 feet) of any proposed drilling location or centralized flowback water impoundment if proposed.
    - List of municipal officials contacted for water well information and printed copies of responses
    - List of property owners and tenants contacted for water well information
    - List of adjacent lessees contacted for water well information
    - Printed results of EPA SDWIS search (http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY)
    - Printed results of DEC Water Well search (http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty)
- For a newly proposed surface water withdrawal:
    - Map of drainage area above the withdrawal point.
    - If stream gauge data is available: monthly tabulation for January through December of 30% of average daily flow and 30% of average monthly flow, with calculations and assumptions for calculations.
- Invasive species survey and map
- Proposed fluid disposal plan, pursuant to 6 NYCRR 554.1(c)(1)
    - Planned transport of flowback water off of well pad – trucking or piping
        - If piping, describe construction including size, materials, leak prevention and spill control measures

- Planned disposition of flowback water – treatment facility, disposal well, reuse on same well pad, reuse on another well pad, centralized flowback surface water impoundment, centralized tank facility, or other (describe)
  - If a treatment facility in NY:
    - Name, owner/operator, location
    - SPDES permit # and date if applicable
    - If a POTW, date of NYSDEC approval to receive flowback water (attach a copy of approval notification)
    - Brief description of facility and treatment if not a POTW
  - If a disposal well in NY:
    - SPDES permit # and date
    - EPA UIC permit # and date
  - If a newly proposed centralized flowback water surface impoundment in New York:
    - Location, affirmation of ownership or permission,
    - Distance from edge of impoundment to:
      - any water supply reservoir within 1,320 feet and
      - any perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet
    - Design information necessary to determine applicability of dam safety construction and operational requirements
    - Double liner system specifications – material, thickness, specify clay or GCL for lower composite liner
    - Description of leak detection and groundwater monitoring systems
    - Closure plan
    - Construction as required by Subpart 360-6
    - If available, flowback water analyses for the same specific additive mix (i.e., components and concentrations) used in the same formation within reasonable proximity to the wellbore
    - In the absence of representative flowback water analyses:
      - complete compositional information for any additive not listed on Table 5.3 of the SGEIS
    - Description of planned public access restrictions, including physical barriers and distance to edge of impoundment
    - Other proposed control measures for preventing public exposure to hazardous air pollutants in excess of guidance thresholds (e.g., duration and use limitations, cover, etc.)
  - If a previously proposed or approved centralized flowback water surface impoundment in New York:
    - API # for well permit application associated with previous proposal or approval
  - If a centralized tank facility in New York:
    - Location, affirmation of ownership or permission
    - Certification of compliance with 360-6.3

REQUIRED AFFIRMATIONS

- Any surface water withdrawal associated with this well pad will only occur when flow is above the appropriate threshold as established by NYSDEC –DFWMR (larger of 30%ADF and 30%AMF *or* 0.5/1.0/4.0 cfs/mi^2 per SGEIS Table 7.2)
- Applicable FIRM and Flood Boundary and Floodway maps consulted, and proposed well pad and access road are/are not within a mapped100-year floodplain.
- Any existing comprehensive, open space and/or agricultural plan or similar policy document(s) identified and reviewed by the applicant.
- Baseline residential well sampling, analysis and ongoing monitoring will be conducted and results shared with property owner and county health department as described in SGEIS and permit conditions.
- Unless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property.
- MSGP authorization for stormwater discharges will be obtained prior to site disturbance.
- Use of ultra-low sulfur fuel (< 15 ppm)
- Operator will prepare and adhere to the following site plans, which will be available to the Department upon request and available on-site to Department inspector while activities addressed by the plan are occurring:
  - a visual impacts mitigation plan consistent with the SGEIS;
  - a noise impacts mitigation plan consistent with the SGEIS;
  - a greenhouse gas impacts mitigation plan consistent with the SGEIS; and
  - an invasive species mitigation plan which includes:
    - the best management practices listed in the SGEIS and
    - seasonally appropriate site-specific and species-specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.) based on the invasive species survey submitted with the EAF Addendum.
- Operator will adhere to all well permit conditions, including requirement for Department approval prior to making any change.

ADDITIONAL SUBMISSIONS REQUIRED PRIOR TO SITE DISTURBANCE

- Road use agreement with local governing authority OR trucking plan and documentation of efforts to obtain a road use agreement
- Local floodplain development permit, if required

New York State

DEC

Division of Mineral Resources

Appendix 7

Sample Drilling Rig Specifications

Provided by Chesapeake Energy

Draft Supplemental Generic Environmental Impact Statement

ATTACHMENT A
RIG SPECIFICATIONS
Example #1

National Cabot 900
Working Depth: 12,000'

DRAWWORKS:	National Model 2346 – Mechanical – Grooved for 1 1/8'' drilling line. Air operated, water cooled Eaton Assist Brake	
ENGINES:	2 - Cat C-15 (475HP ea.) with Allison Transmissions	
MAST:	NOV - 117' - 350,000 SHL on 8 lines	
SUBSTRUCTURE:	NOV - 18' Floor Height /15' Working Height	
TRAVELING EQUIPMENT:	IDECO UTB – 265 Ton Block and Hook	
ROTARY TABLE:	27 ½'' with 440,000# capacity	
TUBULARS:	12,000' - S-135 - 4 1/2''x 16.60# per foot w/ XH connections 18 - 6 ½'' collars with NC46 connections	
MUD PUMPS:	2 – National 9-P-100 with Cat 3508 Mechanicals (935HP ea.)	
MUD SYSTEM:	3 - Tank, 900 BBL total	
SOLIDS CONTROL EQUIPMENT:	Shakers: Desander: Desilter: Agitators:	2 – NOV D285P-LP Brandt - 2 - 10" Cones Brandt - 12 - 4" Cones 6 – Brandt with 36'' Impellers
BOP EQUIPMENT:	1 - Shaffer LXT - 11" 5M - Double Ram 1 – Shaffer Spherical - 11" 5M - Annular	
CLOSING UNIT:	Koomey - 6 Station - 160 Gallon; 3000 psi	
CHOKE MANIFOLD:	3'' x 4'' - 5M, 1 Hydraulic Choke and 1 Manual Choke	
GENERATORS:	2 - Caterpillar 545 kW, Powered by 2 Cat C-18's	
AUXILARY EQUIPMENT:	Water Tank: 400 BBL Fuel Tank: 10,000 Gallons	
SPECIAL TOOLS:	2 - Braden PD12C Hydraulic Hoist Hydraulic Pipe Spinner Oil Works OWI-1000 Wire line with 12,000' of wire	

Rig Specifications
Example #2

---

610 Mechanical 750 HP
Working Depth: 14,000’

DRAWWORKS:	National 610 Mechanical Wichita 325 Air Brake
ENGINES:	2 – Caterpillar C-18’s, 600 HP Each
MAST:	Dreco 142’ 550,000 SHL on 10 Lines
SUBSTRUCTURE:	Dreco 20’ Box on Box
TRAVELING EQUIPMENT:	Block-Hook: Ideco UTB-265-5-36
ROTARY TABLE:	National C-275
COMPOUND:	National 2 Engines
TORQUE CONVERTERS:	2 – National C195
MUD PUMPS:	2 – National 9-P-100, Independent Drive Cummins QSK38, 920 HP
MUD SYSTEM:	2 – Tank, 750 BBL total w/100 BBL Premix
SOLIDS CONTROL EQUIPMENT:	Shakers: 2 – National Model DLMS-285P Desander: National with 2 - 10” Cones Desilter: National with 16 - 4” Cones
BOP EQUIPMENT:	1 – Shaffer LWS Type 11” 5M 1 – Shaffer Spherical Type 11: 5M
CLOSING UNIT:	Koomey 6 Station 180 Gallon; 1 Air and 1 Electrical Pump
CHOKE MANIFOLD:	4’’ x 3’’ 5M, 2 Adjustable Chokes
GENERATORS:	2 – Cat 545 kW, Powered by 2 Cat C-18’s
AUXILARY EQUIPMENT:	Water Tank: 500 BBL Fuel Tank: 12,000 Gallons
SPECIAL TOOLS:	ST-80 Iron Roughneck Pipe Spinner: Hydraulic Auto Driller: Satellite Totco EDR (Rental) Separator/Trip Tank Combo (Rental) Hoists: 1 – Thern 2.5A Air Hoist 1 - Braden PD12C Hydraulic Hoist

Rig Specifications
Example #3

SpeedStar 185K -- 515 HP
Working Depth: 8,000’

ENGINE: 1 – Caterpillar C-15 with Allison Transmission

MAST: SpeedStar – 61’ – 185,000 LB SHL
Setback Capacity of 7,000’ – 3.5” Drill Pipe

SUBSTRUCTURE: Box Type – 7’6” Working Height

MUD PUMP: 1 – MP5

MUD SYSTEM: 2 – Tank, 600 BBL

BOP EQUIPMENT: 11” x 3M Annular

CLOSING UNIT: Townsend 4 Station, 80 Gallon

CHOKE MANIFOLD: 3’’ x 3’’ 5K with 1 Hydraulic Choke

GENERATORS: 2 – Onan 320 kW with Cummins Engines

DRILL PIPE: 7,500’ OF 3.5” 13.30 LB/FT with IF Connections

DRILL COLLARS: 12 – 6 ½”

AIR SYSTEM: 3 – Ingersoll Rand 1170/350 Air Compressors
2 – Single Stage Boosters

AUXILARY EQUIPMENT: Water Tank: 250 BBL
Fuel Tank: 3,500 Gallons

SPECIAL TOOLS: 2 – Braden PD12C Hydraulic Tub Winches
Myers 35GPM Soap Pump
Martin Decker Geolograph
Wireline Unit with 10,000’ of Line

New York State

DEC

Division of Mineral Resources

Appendix 8

Casing & Cementing Practices Required for All Wells in NY

Draft Supplemental Generic Environmental Impact Statement

New York State Department of Environmental Conservation
Casing and Cementing Practices

SURFACE CASING

1. The diameter of the drilled surface casing hole shall be large enough to allow the running of centralizers in recommended hole sizes.

RECOMMENDED CENTRALIZER-HOLE SIZE COMBINATIONS		
Centralizer Size Inches	**Minimum Hole Sizes Inches**	**Minimum Clearance Inches**
4-1/2	6-1/8	1-5/8
5-1/2	7-3/8	1-7/8
6-5/8	8-1/2	1-7/8
7	8-3/4	1-3/4
8-5/8	10-5/8	2
9-5/8	12-1/4	2-5/8
13-3/8	17-1/2	4-1/8

NOTE: (1) If a manufacturer's specifications call for a larger hole size than indicated in the above table, then the manufacturer's specs take precedence.

(2) Check with the appropriate regional office for sizes not listed above.

2. Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.

3. Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).

4. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.

5. Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.

6. Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.

7. The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.

8. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.

9. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.

10. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.

11. When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.

    WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

    THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL SURFACE CASING CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

    THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE STAFF.

INTERMEDIATE CASING

Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.

PRODUCTION CASING

12. The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.

13. Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.

14. The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the

lowest (deepest) full joint of casing.

15. The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.

16. Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.

17. The annular space between the surface casing and the production string shall be vented at all times. If the annular gas is to be produced, a pressure relief valve shall be installed in an appropriate manner and set at a pressure approved by the Regional Mineral Resources office.

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL PRODUCTION CASING/ CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE.

New York State

DEC

Division of Mineral Resources

Appendix 9

Fresh Water Aquifer Supplementary Permit Conditions Required for All Wells in Primary and Principal Aquifers

Draft Supplemental Generic Environmental Impact Statement

FRESH WATER AQUIFER SUPPLEMENTARY PERMIT CONDITIONS

Operator: Well Name:
API Number:

1. All pits must be lined and sized to fully contain all drilling, cementing and stimulation fluids plus any fluids as a result of natural precipitation. Use of these pits for any other purpose is prohibited.

2. All fluids must be contained on the site and properly disposed. If operations are suspended and the site is left unattended at any time, pit fluids must be removed from the site immediately. After the cessation of drilling and/or stimulation operations, pit fluids must be removed within 7 days. Disposal of fluids must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

3. Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.

4. If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

5. A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

6. If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.

7. In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations. This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.

8. This office must be notified _______ hours prior to any stimulation operation. Stimulation may commence without the state inspector if the inspector is not on location at the time specified during the notification.

9. The operator must complete the "Record of Formations Penetrated" on the Well Drilling and Completion Report providing a log of formations, both unconsolidated and consolidated, and all water and gas producing zones.

10. If the well is a producer, holding tanks with water-tight diking capable of retaining 1½ times the capacity of the tank must be installed for the containment of oil, brine and other production fluids. Disposal of fluids must only be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

11. **Any deviation from the above conditions must be approved by the Department prior to making a change.**

New York State

DEC

Division of Mineral Resources

Appendix 10

PROPOSED
Supplementary Permit Conditions
For High-Volume Hydraulic Fracturing

Draft Supplemental Generic Environmental Impact Statement

PROPOSED Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

Planning and Local Coordination

1) All operations authorized by this permit must be conducted in accordance with the following site-specific plans prepared by the operator, available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place:
   a) a visual impacts mitigation plan consistent with the SGEIS,
   b) a noise impacts mitigation plan consistent with the SGEIS,
   c) a greenhouse gas emissions impacts mitigation plan consistent with the SGEIS, and
   d) an invasive species mitigation plan which includes:
      i) the best management practices listed in the SGEIS and
      ii) seasonally appropriate site-specific and species-specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.) based on the invasive species survey submitted with the EAF Addendum.

2) The county emergency management office (EMO) must be notified of the well's location and the potential hazards involved as follows:
   a) prior to spudding the well,
   b) during any flaring while drilling,
   c) prior to high-volume hydraulic fracturing, and
   d) prior to flaring for well clean-up, treatment or testing.

   A record of the type, date and time of any notification provided to the EMO must be maintained by the operator and made available to the Department upon request. In counties without an EMO, the local fire department must be notified as described above.

3) Issuance of this permit does not provide relief from any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Prior to site disturbance, the operator shall submit to the Department, for informational purposes only, a copy of any road use agreement between the operator and municipality. If no road use agreement has been reached, the operator shall file its trucking plan with the Department, for informational purposes only, along with documentation of its efforts to reach a road use agreement.

4) A copy of any required local floodplain development permit must be provided to the Department prior to any site disturbance.

5) Prior to site disturbance (for a new well pad) or spud (for an existing pad), the well operator must sample and test residential water wells within 1,000 feet of the well pad as described by the SGEIS, and provide results to the property owner and the county health department. If no wells are available for sampling within 1,000 feet, either because there are none of record or because the property owner denies permission, then wells within 2,000 feet must be sampled and tested with the property owner's permission.

6) Ongoing water well monitoring and testing must continue as described by the SGEIS until one year after hydraulic fracturing at the last well on the pad. More frequent or additional monitoring and testing may be required by the Department in response to complaints.

7) Water well analysis must be by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the property owner and the county health department must be maintained by the operator and made available to the Department upon request.

Site Preparation

8) Unless otherwise required by private lease agreement, the access road must be located as far as practical from occupied structures, places of assembly and unleased property.

9) Unless otherwise approved or directed by the Department, all of the topsoil in the project area stripped to facilitate the construction of well pads and access roads must be stockpiled and remain on site for use in final reclamation.

10) Authorization under the Department's Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (GP-0-06-002) (MSGP) must be obtained prior to any disturbance at the site.

11) Piping and conveyance used for flowback water must be constructed of materials compatible with flowback water composition and in accordance with the fluid disposal plan approved by the Department pursuant to 6 NYCRR 554.1(c)(1).

12) Any reserve pit, drilling pit or mud pit on the well pad which will be used for more than one well must be constructed as follows:

    a) Surface water and stormwater runoff must be diverted away from the pit,

    b) Pit volume may not exceed 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land,

    c) Pit sidewalls and bottoms must adequately cushioned and free of objects capable of puncturing and ripping the liner,

    d) Pits constructed in unconsolidated sediments must have beveled walls (45 degrees or less),

    e) The pit liner must be sized and placed with sufficient slack to accommodate stretching,

    f) Liner thickness must be at least 30 mils, and

    g) Seams must be factory installed or field seamed in accordance with the manufacturer's recommendations.

Site Maintenance

13) For multi-well pads:

a) Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks, (SPOTS 10) is required for all fuel tanks larger than 10,000 gallons,

b) To the extent practical, fuel tanks will not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond,

c) To the extent practical, fuel tanks at locations within the NYC Watershed boundary shall not be placed within 500 feet of a reservoir, a reservoir stem, a controlled lake or a watercourse, as those terms are defined by the New York City Watershed Rules and Regulations,

d) Secondary containment consistent with the Department's SPOTS 10 is required for fuel tanks smaller than 10,000 gallons if the tanks are located within the boundaries of primary or principal aquifers or within 500 feet of the water resources listed in items b and c above,

e) Tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and

f) Troughs, drip pads or drip pans are required beneath the fill port of a fuel tank during filling operations if the fill port is not within the secondary containment.

14) A copy of the SWPPP must be available on-site and available to Department inspectors while MSGP coverage is in effect. MSGP coverage may be terminated upon completion of all drilling and hydraulic fracturing operations, fracturing flowback operations and partial site reclamation. Partial site reclamation has occurred when a Minerals inspector verifies that drilling and fracturing equipment has been removed, pits used for those operations have been reclaimed and surface disturbances not associated with production activities have been re-graded and seeded, and vegetative cover re-established. The operator may maintain coverage upon choice. Coverage must be maintained if there has been a discharge of a reportable quantity of oil or a hazardous substance for which notification is required under 40 CFR 11.6, 40 CFR 117.20 or 40 CFR 302.6.

15) Freeboard monitoring is required for any on-site pit and 2 feet of freeboard must be maintained at all times.

16) Fluids must be removed from any on-site pit prior to any 45-day gap in use and the pit must be inspected by a Department inspector prior to resumed use. If the well pad is in a primary or principal aquifer area or within the boundaries of an unfiltered water supply, pit fluids must be removed immediately if operations are suspended and the site will be left unattended.

Drilling, Stimulation and Flowback

NOTE: Wildcat Supplementary Conditions and Fresh Water Aquifer Supplementary Conditions may be separately imposed in addition to these. Unless superseded by more stringent conditions below and/or by the Aquifer Conditions, the Department's Casing and Cementing Practices also remain in effect.

17) Lighting and noise mitigation measures as deemed necessary by the Department may be required at any time.

18) The operator must provide the drilling company with a well prognosis indicating anticipated formation top depths with appropriate warning comments prior to spud. The prognosis must be reviewed by all crew members and posted in a prominent location in the doghouse. The operator must revise the prognosis and inform the drilling company in a timely manner if drilling reveals significant variation between the anticipated and actual geology and/or formation pressures.

19) Individual crew member's responsibilities for blowout control must be posted in the doghouse and each crew member must be made aware of such responsibilities prior to spud.

20) Appropriate pressure control procedures and equipment must be employed while drilling, tripping, logging and running casing into the well.

21) In the event H_2S is encountered, all regulated activities must be conducted by the operator in conformance with American Petroleum Institute Publication API RP49, "Recommended Practices For Safe Drilling of Wells Containing Hydrogen Sulfide."

22) Annular disposal of drill cuttings or fluid is prohibited.

23) All fluids must be contained on the site until properly removed in compliance with the fluid disposal plan approved in accordance with 6 NYCRR 554.1(c)(1) and applicable conditions of this permit.

24) For floodplain locations, a closed loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings.

25) Only biocides with current registration for use in New York may be used for any operation at the wellsite. Products must be properly labeled, and the label must be kept on-site during application and storage.

26) This office must be notified _______ hours prior to surface casing cementing operations. If the location is within a primary or principal aquifer, cementing cannot commence until a Department inspector is present. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

27) If intermediate casing is not installed, then production casing must be fully cemented to surface. If intermediate casing is installed, it must be fully cemented to surface and production casing cement must be tied into the intermediate casing string with at least 300 feet of cement. Any request to waive the preceding requirement must be made in writing with supporting documentation and is subject to the Department's approval. The Department will only approve a waiver if open-hole wireline logs and all other information collected during drilling from the same well pad verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented. In any event, the top of cement on the production casing must be at least 500 feet above the casing shoe or tied into the previous casing string with at least 300 feet of cement.

28) The operator must run a cement bond log to verify the cement bond on the intermediate casing, if any, and the production casing. Remedial cementing shall be required if the cement bond is not adequate to isolate hydraulic fracturing operations.

29) Under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test.

30) If hydraulic fracturing operations are performed down casing, the casing extending from the surface of the well to the top of the treatment interval must first be tested to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

31) The operator must record the depths and estimated flow rates where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations. This information and the Department's *Pre-Frac Checklist and Certification* form must be submitted to and received by the regional office at least 48 hours prior to commencement of high-volume hydraulic fracturing operations. The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification* is received by the Department at least 48 hours in advance and 3) all other pre-frac notification requirements are met as specified elsewhere. The operator is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the *Pre-Frac Checklist and Certification*.

32) Fracturing products other than those identified in the well permit application materials may not be used without specific approval from this office. The Department will require submission and review of chemical information for any product which has not previously been reviewed, and may require a site-specific environmental assessment and SEQRA determination prior to approving commencement of hydraulic fracturing operations based on a change in fracturing products.

33) Hydraulic fracturing operations must be conducted as follows:

    a) The operator or operator's designated representative must be on site throughout hydraulic fracturing operations,

    b) Secondary containment for fracturing additive containers and staging areas may be required by the Regional Minerals Manager if the proposed location or operation raises a concern about potential liquid chemical releases that is not, in the Department's judgment, sufficiently addressed by the GEIS, the SGEIS, inherent mitigation factors and setbacks. Any such secondary containment must be sufficient to contain 110% of the single largest liquid chemical container within a common staging area,

    c) Hydraulic fracturing additives must be removed from the site if the site will be unattended,

    d) Any frac string, if used, must be either stung into a production liner or run with a packer set at least 100 feet below the deepest cement top. An adequately sized, function tested relief valve and an adequately sized diversion line must be installed and used to divert flow from the frac string-casing annulus to a lined pit or containment vessel in case of frac string failure. The relief valve must be set to limit the annular pressure to no more than 95% of the lowest internal yield pressure rating of the casing forming the annulus. The annulus between the frac string and casing must be pressurized to at least 250 psig and monitored,

e) The pressure exerted on treating equipment including valves, lines, frac head or tree, casing and frac string, if used, must not exceed 95% of the lowest internal yield pressure rating of the weakest component, and

f) All annuli must be continuously observed or monitored in order to detect pressure or flow, and the records of such maintained by the operator and made available to the Department upon request.

34) The operator must make and maintain a complete record of its hydraulic fracturing operation including the flowback phase, and provide such to the Department upon request at any time during the life of the well (i.e., until the well is permanently plugged and abandoned). The record must include all types and volumes of materials, including additives, pumped into the well and the volume of fluid recovered during the flowback phase. The record must also include a complete description of pressures exhibited throughout the hydraulic fracturing operation and must include pressure recordings, charts and/or a pressure profile. A synopsis of the hydraulic fracturing operation must be provided in the appropriate section of the *Well Drilling and Completion Report.*

35) Flowback water must not be directed to any on-site pit. Steel tanks are required for flowback handling and containment on the well pad. Fluid transfer operations from tanks to tanker trucks must be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck.

36) In no event will flowback water from this location be piped or transported to a centralized surface impoundment located within the boundaries of a primary or principal aquifer or an unfiltered water supply, or a centralized surface impoundment elsewhere that has not been approved by the Department pursuant to a fluid disposal plan in accordance with 6 NYCRR 554.1(c)(1).

37) The venting of any gas originating from the target formation during the flowback phase must be through a flare stack at least 30 feet in height, unless the absence of H2S has been demonstrated at a previous well on the same pad. Vented gas should be ignited whenever possible.

38) This permit authorizes a one-time single-stage or multi-stage high-volume hydraulic fracturing operation as described in the well permit application materials, subject to the *Pre-Frac Checklist and Certification* and any modifications required by the Department. Any subsequent high-volume re-fracturing operations are subject to the Department's approval after:

a) review of the planned fracturing procedures and products, water source, proposed site disturbance and layout, and fluid disposal plans,

b) a site inspection by Department staff, and

c) a determination of whether any other Department permits are required. If MSGP coverage has been terminated, then it must be re-attained prior to any site disturbance associated with high-volume re-fracturing.

Reclamation

39) Fluids must be removed from any on-site pit and the pit reclaimed no later than 45 days after completion of drilling and stimulation operations at the last well on the pad, unless the Department grants an extension pursuant to 6 NYCRR 554.1(c)(2). If the well pad is in a primary or principal aquifer area or within the boundaries of an unfiltered water supply, pit fluids must be removed no later than 7 days after completing drilling and stimulation operations at the last well on the pad. Flowback water must be removed from on-site tanks within the same time frames.

40) Removed pit fluids must be disposed, recycled or reused as described in the approved fluid disposal plan submitted pursuant to 6 NYCRR 554.1(c)(1). 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.

41) If any fluid or other waste material is moved off site by pipeline or other piping, the operator must maintain a record of the date and time the fluid or other material left the site, the quantity of fluid or other material, and its intended destination and use at that destination or receiving facility.

42) Flowback water piping and conveyances must be constructed of suitable materials, maintained in a leak-free condition, regularly inspected and operated using all appropriate spill control and stormwater pollution prevention practices.

43) Consultation with the Department's Division of Solid and Hazardous Materials is required prior to disposal of any pit solids and pit liner associated with mud-drilling. Any sampling and analysis directed by DSHM must be by an ELAP-certified laboratory. Disposal must conform to all applicable Department regulations. The pit liner must be ripped and perforated prior to any permitted burial on-site. Permission of the surface owner is required for any on-site burial of pit solids and pit liner, regardless of type of drilling and fluids used. Burial of any other trash on-site is specifically prohibited and all such trash must be removed from the site and properly disposed. Transport of all pit solids and pit liner off-site, if required by the Department or otherwise performed, 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.

44) Unless otherwise approved by this office, well pads and access roads constructed for drilling and production operations must be scarified or ripped to alleviate compaction prior to

replacement of topsoil. Reclaimed areas must be seeded and mulched after topsoil replacement. Any proposal by the operator to waive these reclamation requirements must be accompanied by documentation of the landowner's written request to keep the access road and/or well pad.

General

45) The operator must complete the "Record of Formations Penetrated" on the Well Drilling and Completion Report providing a log of formations, both unconsolidated and consolidated, and depths and estimated flow rates of any fresh water, brine, oil and/or gas.

46) Any non-routine incident must be verbally reported to the Department within two hours of the incident's occurrence or discovery, with a written report detailing the non-routine incident to follow within twenty-four hours of the incident's occurrence or discovery. Non-routine incidents include, but are not limited to: casing, drill pipe or frac equipment failures, cement failures, fishing jobs, fires, seepages, blowouts, surface chemical spills, observed leaks in surface equipment, observed pit liner failure, surface effects at previously plugged or unknown wells, observed effects at water wells or at the surface, complaints of water well contamination or other potentially polluting non-routine incident or incident that may affect the health, safety, welfare, or property of any person.

47) Fluids recovered after high volume hydraulic fracturing operations must be tested for NORM during flowback operations prior to removal from the site. Fluids recovered during the production phase (i.e., produced brine) must be tested for NORM prior to removal, and the ground adjacent to the tanks must be measured for radioactivity. All testing must be in accordance with protocols satisfactory to NYSDOH.

48) Produced brine which is removed from the site must be disposed, recycled or reused as described by the well permit application materials. Transport of all waste fluids 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.

Any deviation from the above conditions must be approved by the Department prior to making a change.

New York State

DEC

Division of Mineral Resources

Appendix 11

Analysis of Subsurface Mobility of Fracturing Fluids

Excerpted from ICF International, Task 1, 2009

Draft Supplemental Generic Environmental Impact Statement

1.2.4 Principles governing fracturing fluid flow

The mobility of hydraulic fracturing fluid depends on the same physical and chemical principles that dictate all fluid transport phenomena. Frac fluid will flow through the well, the fractures, and the porous media based on pressure differentials and hydraulic conductivities. In addition to the overall flow of the frac fluids, additives may experience greater or lesser movement due to diffusion and adsorption. The concentrations of the fluids and additives may change due to dilution in formation waters and possibly by biological or chemical degradation.

1.2.4.1 Limiting conditions

The analyses below present flow calculations for a range of parameters, with the intent to define reasonable bounds for the conditions likely to be encountered in New York State. Although one or more conditions at some future well sites may lie outside of the ranges analyzed, it is considered unlikely that the combination of conditions at any site would produce environmental impacts that are significantly more adverse than the worst case scenarios analyzed. The equations used in the analyses are presented below to facilitate the assessment of additional scenarios.

The analyses consider potentially useful aquifers with lower limits at depths up to 1,000 feet, somewhat deeper than the maximum aquifer depth reported in Table 3 for the Marcellus Shale. Similarly, the minimum depth to the top of the shale is taken as 2,000 ft, well above the minimum depth reported in Table 3 for the Marcellus Shale. The 2,000 ft. depth has been postulated as the probable upper limit for economic development of the New York shales.

The analyses include an additional conservative assumption. Even for deep aquifers, the analyses consider the pore pressure at the bottom of the aquifer to be zero as if a deep well or well field was operating at maximum drawdown. This assumption maximizes the potential for upward flow of fracturing fluid or its components from the fracture zone to the aquifer.

[134] U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

1.2.4.2 Gradient

For a fracturing fluid or its additives to have a negative impact on a groundwater aquifer, some deleterious component of the fracturing fluid would need to travel from the target fracture zone to the aquifer. In order for fluid to flow from the fracture zone to an aquifer, the *total head*[135] must be greater in the fracture zone than at the well. We can estimate the *gradient*[136] that might exist between a fracture zone in the shale and a potable water aquifer as follows:

$$i = \frac{h_{t1} - h_{t2}}{L} \quad (1)$$

where i = gradient
h_{tn} = total head at Point n
L = length of flow path from Point 1 to Point 2

Since the total head is the sum of the elevation head and the pressure head,

$$h_t = h_e + h_p \quad (2)$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \quad (3)$$

where h_{en} = elevation head at Point n
h_{pn} = pressure head at Point n

If the ground surface is taken as the elevation datum, we can express the elevation head in terms of depth.

$$d_n = -h_{en} \quad (4)$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \quad (5)$$

where d_n = depth at Point n

We can estimate the maximum likely gradient by considering the combination of parameters which would be most favorable to flow from the hydraulically fractured zone to a potential groundwater aquifer. These include assuming the minimum possible pressure head in the aquifer and the shortest possible flow path, i.e. setting h_{p2} to zero to simulate a well pumped to the maximum aquifer drawdown and setting L to the vertical distance between the fracture zone and the aquifer, $d_1 – d_2$.

135 Total head at a point is the sum of the elevation at the point plus the pore pressure expressed as the height of a vertical column of water.
136 The groundwater gradient is the difference in total head between two points divided by the distance between the points.

The gradient now becomes

$$i = \frac{(d_2 - d_1) + h_{p1}}{|d_1 - d_2|} \tag{6}$$

The total vertical stress in the fracture zone equals

$$\sigma_v = d_1 \times \gamma_R \tag{7}$$

where σ_v = total vertical stress
d_1 = depth at Point 1, in the fracture zone
γ_R = average total unit weight of the overlying rock

The effective vertical stress, or the stress transmitted through the mineral matrix, equals the total unit weight minus the pore pressure. For the purposes of this analysis, the pore pressure is taken to be equivalent to that of a vertical water column from the fracture zone to the surface. The effective vertical stress is given by

$$\sigma'_v = \sigma_v - (d_1 \times \gamma_W) \tag{8}$$

where σ'_v = effective vertical stress
γ_W = unit weight of water

The effective horizontal stress and the total horizontal stress therefore equal

$$\sigma'_h = K \times \sigma'_v \tag{9}$$

$$\sigma_h = \sigma'_h + (d_1 \times \gamma_W) \tag{10}$$

where σ'_h = effective horizontal stress
K = ratio of horizontal to vertical stress
σ_h = total horizontal stress

The hydraulic fracturing pressure needs to exceed the minimum total horizontal stress. Allowing for some loss of pressure from the wellbore to the fracture tip, the pressure head in the fracture zone equals

$$h_{p1} = c \times \sigma_h = \frac{c \times d_1 \times [K(\gamma_R - \gamma_W) + \gamma_W]}{\gamma_W} \tag{11}$$

where h_{p1} = pressure head at Point 1, in the fracture zone
c = coefficient to allow for some loss of pressure from the wellbore to the fracture tip

Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth.[137] To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress, yielding

$$h_{p1} = \frac{110\% \times d_1 \times [0.75(150\,pcf - 62.4\,pcf) + 62.4\,pcf]}{62.4\,pcf} = 2.26 d_1 \qquad (12)$$

Equation (6) thus becomes

$$i = \frac{(d_2 - d_1) + 2.26 d_1}{|d_1 - d_2|} = \frac{d_2 + 1.26 d_1}{|d_1 - d_2|} \qquad (13)$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

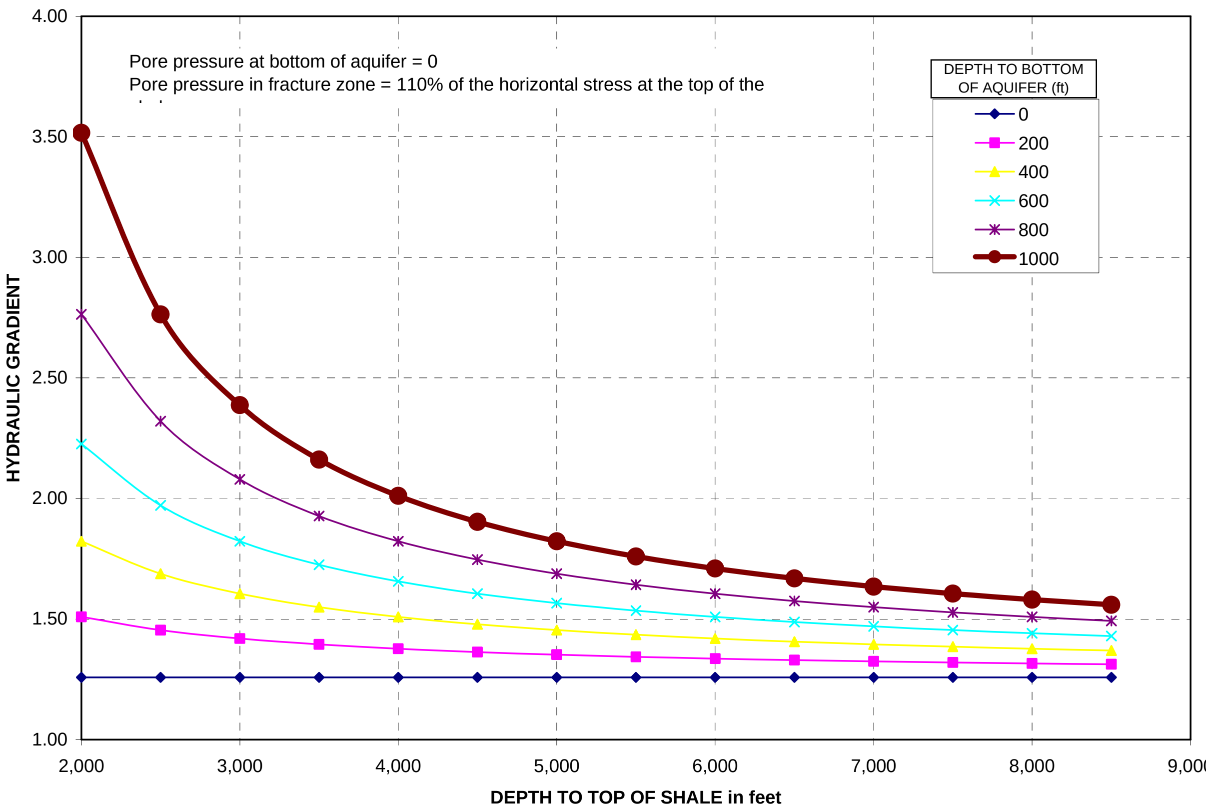


Figure 1: Average hydraulic gradient during fracturing

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

137 Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.[138] During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \tag{10}$$

where v = seepage velocity
k = hydraulic conductivity
n = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.[139] Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

Table 4: Hydraulic conductivity of rock masses[140]

Material	Minimum k	Maximum k
Intact Sandstone	1E-8 cm/sec	1E-5 cm/sec
Sandstone rock mass	1E-9 cm/sec	1E-1 cm/sec
Intact Shale	1E-11 cm/sec	1E-9 cm/sec
Shale rock mass	1E-9 cm/sec	1E-4 cm/sec

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

[138] Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.
[139] Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.
[140] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.[141] Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

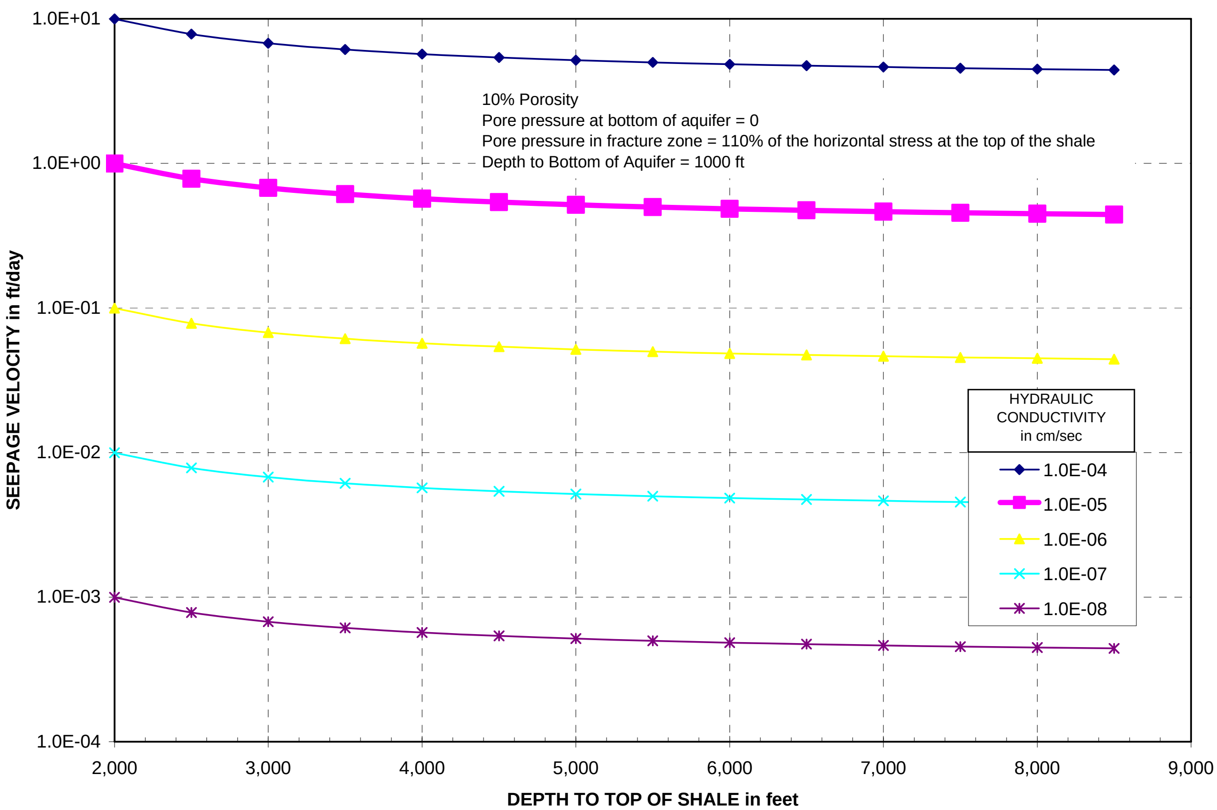


Figure 2: Seepage velocity as a function of hydraulic conductivity

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

[141] DOE, Office of Fossil Energy, 2009. *State Oil and National Gas Regulations Designed to Protect Water Resources*, May 2009.

1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \qquad (11)$$

where t = required travel time

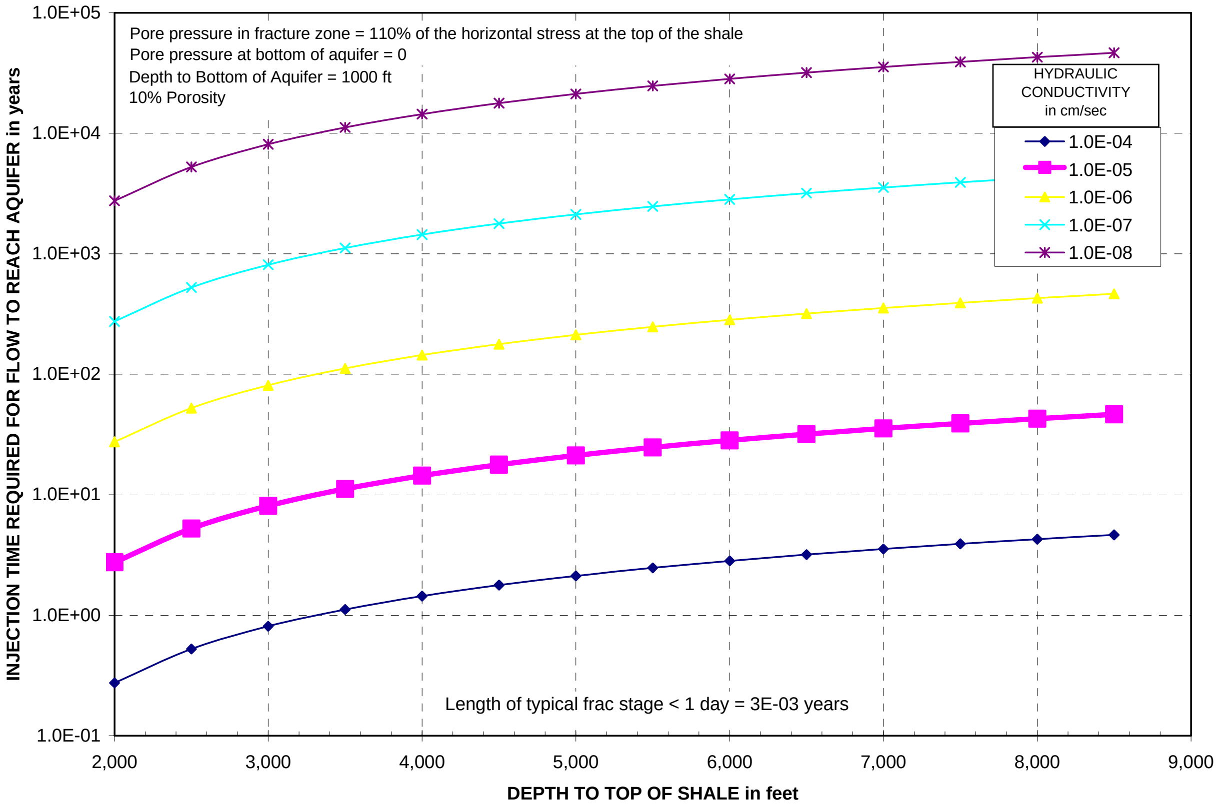


Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity

Figure 3 shows the required travel time based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the required flow time would be longer. The required flow times under the fracturing pressure is several orders of magnitude greater than the duration over which the fracturing pressure would be applied.

Figure 4 presents the results of a similar analysis, but with the hydraulic conductivity held at 1E-5 cm/sec and considering various depths to the bottom of the aquifer. Compared to a 1000 ft. deep aquifer, 10 to 20 more years of sustained fracturing pressure would be required for the fracturing fluid to reach an aquifer that was only 200 ft. deep.

The required travel times shown relate to the movement of the groundwater. Dissolved chemicals would move at a slower rate due to retardation. The retardation factor, which is the ratio of the chemical movement rate compared to the water movement rate, is always between 0.0 and 1.0, so the required travel times for any dissolved chemical would be greater than those shown in Figures 3 and 4.

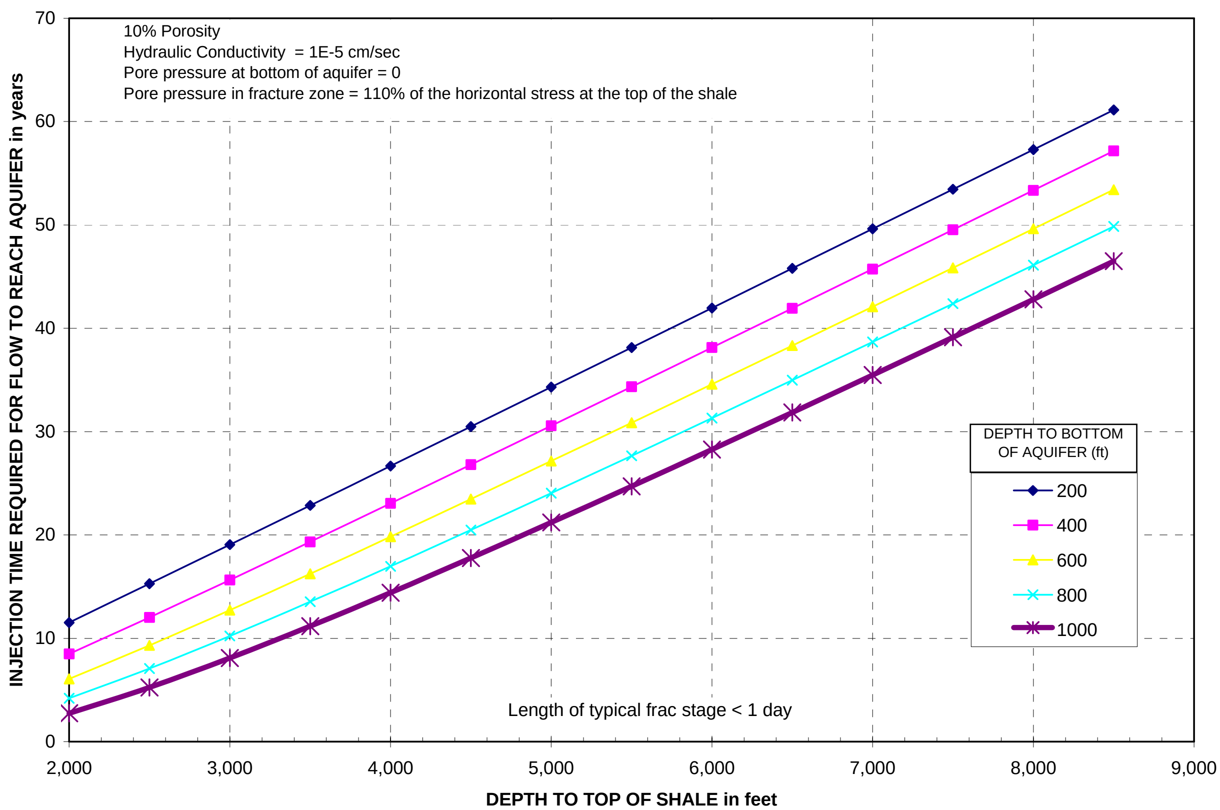


Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth

1.2.4.5 Pore storage volume

The fourth aspect to consider in evaluating the potential for adverse impacts to overlying aquifers is the volume of fluid injected compared to the volume of the void spaces and fractures that the fluid would need to fill in order to flow from the fracture zone to the aquifer. Figure 5 shows the void volume based on 10% total porosity for the geologic materials for various combinations of depths for the bottom of an aquifer and for the top of the shale, calculated as follows:

$$V = \left| d_1 - d_2 \right| \times n \times \frac{43{,}560\, ft^2}{acre} \times \frac{7.48 gal}{ft^3} \qquad (12)$$

where V = volume of void spaces and fractures

A typical slickwater fracturing treatment in a horizontal well would use less than 4 million gallons of fracturing fluid, and some portion of this fluid would be recovered as flowback. The void volume, based on 10% total porosity, for the geologic materials between the bottom of an aquifer at 1,000 ft. depth and the top of the shale at a 2,000 ft. depth is greater than 32 million gallons per acre. Since the expected area of a well spacing unit is no less than the equivalent of

40 acres per well,[142,143,144,145] the fracturing fluid could only fill about 0.3% of the overall void space. Alternatively, if the fracturing fluid were to uniformly fill the overall void space, it would be diluted by a factor of over 300. As shown in Figure 5, for shallower aquifers and deeper shales, the void volume per acre is significantly greater.

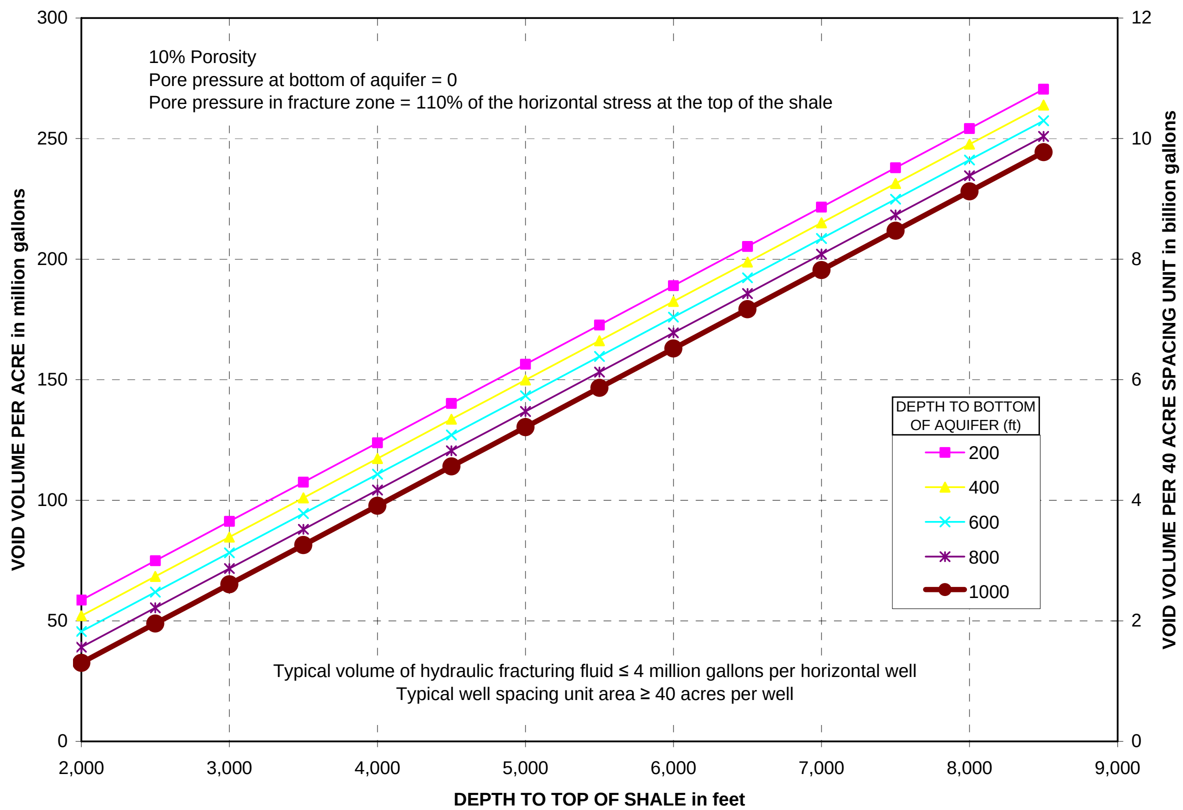


Figure 5: Comparison of void volume to frac fluid volume

1.2.5 Flow through fractures, faults, or unplugged borings

It is theoretically possible but extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer. The open flow path would have a much smaller area of flow leading to the aquifer and the resistance to flow would be lower. In such an improbable case, the flow velocity would be greater, the time required for the fracturing fluid to reach the aquifer would be shorter, and the storage volume between the fracture zone and the aquifer would be less than in the scenarios described above. The probability of such a combination of unlikely conditions occurring simultaneously (deep aquifer, shallow fracture

[142] Infill wells could result in local increases in well density.
[143] New York regulations (Part 553.1 Statewide spacing) require a minimum spacing of 1320 ft. from other oil and gas wells in the same pool. This spacing equals 40 acres per well for wells in a rectangular grid.
[144] New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Part 553.1 Statewide spacing, (as of 5 April 2009).
[145] NYSDEC, 2009, "Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) 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", February 2009.

zone, and open flow path) is very small. The fracturing contractor would notice an anomaly if these conditions led to the inability to develop or maintain the predicted fracturing pressure.

During flowback, the same conditions would result in a high rate of recapture of the frac fluid from the open flow path, decreasing the potential for any significant adverse environmental impacts. Moreover, during production the gradients along the open flow path would be toward the production zone, flushing any stranded fracturing fluid in the fracture or unplugged wellbore back toward the production well.

1.2.6 Geochemistry

The ability of the chemical constituents of the additives in fracturing fluids to migrate from the fracture zone are influenced not just by the forces governing the flow of groundwater, but also by the properties of the chemicals and their interaction with the subterranean environment. In addition to direct flow to an aquifer, the constituents of fracturing fluid would be affected by limitations on solubility, adsorption and diffusion.

1.2.6.1 Solubility

The solubility of a substance indicates the propensity of the substance to dissolve in a solvent, in this case, groundwater. The substance can continue to dissolve up to its saturation concentration, i.e. its solubility. Substances with high solubilities in water have a higher likelihood of moving with the groundwater flow at high concentrations, whereas substances with low solubilities may act as longer term sources at low level concentrations. The solubilities of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases such as the IUPAC-NIST Solubility Database.[146]

The solubility of a chemical determines the maximum concentration of the chemical that is likely to exist in groundwater. Solubility is temperature dependent, generally increasing with temperature. Since the temperature at the depths of the gas shales is higher than the temperature closer to the surface where a usable aquifer may lie, the solubility in the aquifer will be lower than in the shale formation.

Given the depth of the New York gas shales and the distance between the shales and any overlying aquifer, chemicals with high solubilities would be more likely to reach an aquifer at higher concentrations than chemicals of low solubility. Based on the previously presented fluid flow calculations, the concentrations would be significantly lower than the initial solubilities due to dilution.

1.2.6.2 Adsorption

Adsorption occurs when molecules of a substance bind to the surface of another material. As chemicals pass through porous media or narrow fractures, some of the chemical molecules may adsorb onto the mineral surface. The adsorption will retard the flow of the chemical constituents relative to the rate of fluid flow. The retardation factor, expressed as the ratio of the fluid flow velocity to the chemical movement velocity, generally is higher in fine grained materials and in materials with high organic content. The Marcellus shale is both fine grained and of high organic content, so the expected retardation factors are high. The gray shales overlying the Marcellus

[146] IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: http://srdata.nist.gov/solubility/index.aspx.

shale would also be expected to substantially retard any upward movement of fracturing chemicals.

The octanol-water partition coefficient, commonly expressed as K_{ow}, is often used in environmental engineering to estimate the adsorption of chemicals to geologic materials, especially those containing organic materials. Chemicals with high partition coefficients are more likely to adsorb onto organic solids and become locked in the shale, and less likely to remain in the dissolve phase than are chemicals with low partition coefficients.

The partition coefficients of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases. The partition coefficient is inversely proportional to solubility, and can be estimated from the following equation[147]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \tag{13}$$

where K_{ow} = octanol-water partition coefficient
S_w = solubility in water at 20ºC in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

---

[147] Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

1.2.7 Conclusions

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

New York State

DEC

Division of Mineral Resources

Appendix 12

Beneficial Use Determination (BUD) Notification Regarding Roadspreading

Draft Supplemental Generic Environmental Impact Statement

New York State Department of Environmental Conservation
Division of Solid and Hazardous Materials
Bureau of Solid Waste, Reduction and Recycling, 9th Floor
625 Broadway, Albany, New York 12233-7253
Phone: (518) 402-8704 • **FAX:** (518) 402-9024
Website: www.dec.ny.gov

Alexander B. Grannis
Commissioner

January 2009

NOTICE TO GAS AND OIL WELL & LPG STORAGE FLUID HAULERS

All gas or oil well drilling and production fluids including but not limited to brine and fracturing fluids, and brine from liquefied petroleum gas (LPG) well storage operations, transported for disposal, road spreading, reuse in another gas or oil well, or recycling must be specifically identified in Part C and D of the New York State Waste Transporter Permit Application Form. Transporters must identify the type of fluid proposed to be transported in Section C in the Non-Hazardous Industrial/Commercial box and the Disposal or Destination Facility (or Use) in Part D.

Fracture fluids obtained during flowback operations may not be spread on roads and must be disposed at facilities authorized by the Department. Such disposal facilities must be identified in Part D of the permit application. If fluids are to be transported for use or reuse at another gas or oil well, that location must be identified in Part D of the permit application.

With respect to fluids transported under a Waste Transporter Permit, only production brines or brine from LPG storage operations may be used for road spreading. Drilling, fracing, and plugging fluids are not acceptable for road spreading.

Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road de-icing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD). If a contract hauler is applying for a Part 364 permit or permit modification to deliver brine to a government agency for road spreading purposes, that government agency must submit the BUD petition. The BUD must be granted and the Part 364 permit/modification must be issued before brine can be removed from the well or LPG storage site for road spreading purposes or storage at an offsite facility.

The BUD petition must include:

1. An original letter signed and dated by the government agency representative or other property owner authorizing the use of brine on the locations identified in below item 3.

2. The name, address and telephone number of the person, company or government official seeking the approval.

3. An identification (or map) of the specific roads or other areas that are to receive the brine and any brine storage locations, excluding the well site storage locations.

4. The physical address of the brine storage locations from which the brine is hauled.

5. For each well field or LPG storage facility, a chemical analysis of a representative sample of the brine performed by a NYSDOH approved laboratory for the following parameters: calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Depending upon the analytical results, the Department may require additional analyses. (This analysis is not required for brine from a LPG well operation with a valid New York State SPDES permit.)

6. A road spreading plan that includes a description of the procedures to prevent the brine from flowing or running off into streams, creeks, lakes and other bodies of water. The plan should include:

- a description of how the brine will be applied, including the equipment to be used and the method for controlling the rate of application. In general this should indicate that the brine is applied by use of a spreader bar or similar spray device with shut-off controls in the cab of the truck; and with vehicular equipment that is dedicated to this use or cleaned of previously transported waste materials prior to this use;
- the proposed rate and frequency of application;
- a description of application restrictions. For dust control and road stabilization use this description should indicate that the brine is not applied: after daylight hours; within 50 feet of a stream, creek, lake or other body of water; on sections of road having a grade exceeding 10 percent; or on wet roads, during rain, or when rain is imminent. For road deicing use, this description should indicate that the brine is applied in accordance NYSDOT Guidelines for Anit-Icing with Liquids and include any other restrictions.

7. Where applicable, a brine storage plan that includes:

- a description of the type, material, size, and number of storage tanks and the maximum anticipated storage;
- procedures for run off and run-on control;
- provisions for secondary containment; and
- a contingency plan.

If you have any questions concerning your permit, please feel free to call this office at (518) 402-8707. You may also visit our public website at the address above for information and forms to download or print.

Waste Transporter Permit Program

New York State

DEC

Division of Mineral Resources

Appendix 13

NYS Marcellus Radiological Data From Production Brine

Draft Supplemental Generic Environmental Impact Statement

NYS Marcellus Radiological Data from Production Brine

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Maxwell 1C	31-101-22963-03-01	10/7/2008	Caton (Steuben)	Gross Alpha	17,940 +/- 8,634 pCi/L
				Gross Beta	4,765 +/- 3,829 pCi/L
				Cesium-137	-2.26 +/- 5.09 pCi/L
				Cobalt-60	-0.748 +/- 4.46 pCi/L
				Ruthenium-106	9.27 +/- 46.8 pCi/L
				Zirconium-95	37.8 +/- 21.4 pCi/L
				Radium-226	2,472 +/- 484 pCi/L
				Radium-228	874 +/- 174 pCi/L
				Thorium-228	53.778 +/- 8.084 pCi/L
				Thorium-230	0.359 +/- 0.221 pCi/L
				Thorium-232	0.065 +/- 0.103 pCi/L
				Uranium-234	0.383 +/- 0.349 pCi/L
				Uranium-235	0.077 +/- 0.168 pCi/L
				Uranium-238	0.077 +/- 0.151 pCi/L
Frost 2	31-097-23856-00-00	10/8/2008	Orange (Schuyler)	Gross Alpha	14,530 +/-3,792 pCi/L
				Gross Beta	4,561 +/- 1,634 pCi/L
				Cesium-137	2.54 +/- 4.64 pCi/L
				Cobalt-60	-1.36 +/- 3.59 pCi/L
				Ruthenium-106	-9.03 +/- 36.3 pCi/L
				Zirconium-95	31.6 +/- 14.6 pCi/L
				Radium-226	2,647 +/- 494 pCi/L
				Radium-228	782 +/- 157 pCi/L
				Thorium-228	47.855 +/- 9.140 pCi/L
				Thorium-230	0.859 +/- 0.587 pCi/L
				Thorium-232	0.286 +/- 0.328 pCi/L
				Uranium-234	0.770 +/- 0.600 pCi/L
				Uranium-235	0.113 +/- 0.222 pCi/L
				Uranium-238	0.431 +/- 0.449 pCi/L
Webster T1	31-097-23831-00-00	10/8/2008	Orange (Schuyler)	Gross Alpha	123,000 +/- 23,480 pCi/L
				Gross Beta	12,000 +/- 2,903 pCi/L
				Cesium-137	1.32 +/- 5.76 pCi/L
				Cobalt-60	-2.42 +/- 4.76 pCi/L
				Ruthenium-106	-18.3 +/- 44.6 pCi/L
				Zirconium-95	34.5 +/- 15.6 pCi/L
				Radium-226	16,030 +/- 2,995 pCi/L
				Radium-228	912 +/- 177 pCi/L
				Thorium-228	63.603 +/- 9.415 pCi/L
				Thorium-230	0.783 +/- 0.286 pCi/L
				Thorium-232	0.444 +/- 0.213 pCi/L
				Uranium-234	0.232 +/- 0.301 pCi/L
				Uranium-235	0.160 +/- 0.245 pCi/L
				Uranium-238	-0.016 +/- 0.015 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Calabro T1	31-097-23836-00-00	3/26/2009	Orange (Schuyler)	Gross Alpha	18,330 +/- 3,694 pCi/L
				Gross Beta	-324.533 +/- 654 pCi/L
				Cesium-137	3.14 +/- 7.19 pCi/L
				Cobalt-60	0.016 +/- 5.87 pCi/L
				Ruthenium-106	17.0 +/- 51.9 pCi/L
				Zirconium-95	24.2 +/- 13.6 pCi/L
				Radium-226	13,510 +/- 2,655 pCi/L
				Radium-228	929 +/- 179 pCi/L
				Thorium-228	45.0 +/- 8.41 pCi/L
				Thorium-230	2.80 +/- 1.44 pCi/L
				Thorium-232	-0.147 +/- 0.645 pCi/L
				Uranium-234	1.91 +/- 1.82 pCi/L
				Uranium-235	0.337 +/- 0.962 pCi/L
				Uranium-238	0.765 +/- 1.07 pCi/L
Maxwell 1C	31-101-22963-03-01	4/1/2009	Caton (Steuben)	Gross Alpha	3,968 +/- 1,102 pCi/L
				Gross Beta	618 +/- 599 pCi/L
				Cesium-137	-0.443 +/- 3.61 pCi/L
				Cobalt-60	-1.840 +/- 2.81 pCi/L
				Ruthenium-106	17.1 +/- 29.4 pCi/L
				Zirconium-95	26.4 +/- 8.38 pCi/L
				Radium-226	7,885 +/- 1,568 pCi/L
				Radium-228	234 +/- 50.5 pCi/L
				Thorium-228	147 +/- 23.2 pCi/L
				Thorium-230	1.37 +/- 0.918 pCi/L
				Thorium-232	0.305 +/- 0.425 pCi/L
				Uranium-234	1.40 +/- 1.25 pCi/L
				Uranium-235	0.254 +/- 0.499 pCi/L
				Uranium-238	0.508 +/- 0.708 pCi/L
Haines 1	31-101-14872-00-00	4/1/2009	Avoca (Steuben)	Gross Alpha	54.6 +/- 37.4 pCi/L
				Gross Beta	59.3 +/- 58.4 pCi/L
				Cesium-137	0.476 +/- 2.19 pCi/L
				Cobalt-60	-0.166 +/- 2.28 pCi/L
				Ruthenium-106	7.15 +/- 19.8 pCi/L
				Zirconium-95	0.982 +/- 4.32 pCi/L
				Radium-226	0.195 +/- 0.162 pCi/L
				Radium-228	0.428 +/- 0.335 pCi/L
				Thorium-228	0.051 +/- 0.036 pCi/L
				Thorium-230	0.028 +/- 0.019 pCi/L
				Thorium-232	0.000 +/- 0.007 pCi/L
				Uranium-234	0.000 +/- 0.014 pCi/L
				Uranium-235	0.000 +/- 0.005 pCi/L
				Uranium-238	-0.007 +/- 0.006 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Haines 2	31-101-16167-00-00	4/1/2009	Avoca (Steuben)	Gross Alpha	70.0 +/- 47.8 pCi/L
				Gross Beta	6.79 +/- 54.4 pCi/L
				Cesium-137	2.21 +/- 1.64 pCi/L
				Cobalt-60	1.42 +/- 2.83 pCi/L
				Ruthenium-106	5.77 +/- 15.2 pCi/L
				Zirconium-95	2.43 +/- 3.25 pCi/L
				Radium-226	0.163 +/- 0.198 pCi/L
				Radium-228	0.0286 +/- 0.220 pCi/L
				Thorium-228	0.048 +/- 0.038 pCi/L
				Thorium-230	0.040 +/- 0.022 pCi/L
				Thorium-232	-0.006 +/- 0.011 pCi/L
				Uranium-234	0.006 +/- 0.019 pCi/L
				Uranium-235	0.006 +/- 0.013 pCi/L
				Uranium-238	-0.013 +/- 0.009 pCi/L
Carpenter 1	31-101-26014-00-00	4/1/2009	Troupsburg (Steuben)	Gross Alpha	7,974 +/- 1,800 pCi/L
				Gross Beta	1,627 +/- 736 pCi/L
				Cesium-137	2.26 +/- 4.97 pCi/L
				Cobalt-60	-0.500 +/- 3.84 pCi/L
				Ruthenium-106	49.3 +/- 38.1 pCi/L
				Zirconium-95	30.4 +/- 11.0 pCi/L
				Radium-226	5,352 +/- 1,051 pCi/L
				Radium-228	138 +/- 37.3 pCi/L
				Thorium-228	94.1 +/- 14.9 pCi/L
				Thorium-230	1.80 +/- 0.946 pCi/L
				Thorium-232	0.240 +/- 0.472 pCi/L
				Uranium-234	0.000 +/- 0.005 pCi/L
				Uranium-235	0.000 +/- 0.005 pCi/L
				Uranium-238	-0.184 +/- 0.257 pCi/L
Zinck 1	31-101-26015-00-00	4/1/2009	Woodhull (Steuben)	Gross Alpha	9,426 +/- 2,065 pCi/L
				Gross Beta	2,780 +/- 879 pCi/L
				Cesium-137	5.47 +/- 5.66 pCi/L
				Cobalt-60	0.547 +/- 4.40 pCi/L
				Ruthenium-106	-16.600 +/- 42.8 pCi/L
				Zirconium-95	48.0 +/- 15.1 pCi/L
				Radium-226	4,049 +/- 807 pCi/L
				Radium-228	826 +/- 160 pCi/L
				Thorium-228	89.1 +/- 14.7 pCi/L
				Thorium-230	0.880 +/- 1.23 pCi/L
				Thorium-232	0.000 +/- 0.705 pCi/L
				Uranium-234	-0.813 +/- 0.881 pCi/L
				Uranium-235	-0.325 +/- 0.323 pCi/L
				Uranium-238	-0.488 +/- 0.816 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Schiavone 2	31-097-23226-00-01	4/6/2009	Reading (Schuyler)	Gross Alpha	16,550 +/- 3,355 pCi/L
				Gross Beta	1,323 +/- 711 pCi/L
				Cesium-137	1.46 +/- 5.67 pCi/L
				Cobalt-60	-2.550 +/- 5.11 pCi/L
				Ruthenium-106	20.6 +/- 42.7 pCi/L
				Zirconium-95	30.6 +/- 12.1 pCi/L
				Radium-226	15,140 +/- 2,989 pCi/L
				Radium-228	957 +/- 181 pCi/L
				Thorium-228	38.7 +/- 7.45 pCi/L
				Thorium-230	1.68 +/- 1.19 pCi/L
				Thorium-232	0.153 +/- 0.301 pCi/L
				Uranium-234	3.82 +/- 2.48 pCi/L
				Uranium-235	0.354 +/- 0.779 pCi/L
				Uranium-238	0.354 +/- 0.923 pCi/L
Parker 1	31-017-26117-00-00	4/2/2009	Oxford (Chenango)	Gross Alpha	3,914 +/- 813 pCi/L
				Gross Beta	715 +/- 202 pCi/L
				Cesium-137	4.12 +/- 3.29 pCi/L
				Cobalt-60	-1.320 +/- 2.80 pCi/L
				Ruthenium-106	-9.520 +/- 24.5 pCi/L
				Zirconium-95	1.39 +/- 6.35 pCi/L
				Radium-226	1,779 +/- 343 pCi/L
				Radium-228	201 +/- 38.9 pCi/L
				Thorium-228	15.4 +/- 3.75 pCi/L
				Thorium-230	1.25 +/- 0.835 pCi/L
				Thorium-232	0.000 +/- 0.385 pCi/L
				Uranium-234	1.82 +/- 1.58 pCi/L
				Uranium-235	0.304 +/- 0.732 pCi/L
				Uranium-238	0.304 +/- 0.732 pCi/L
WGI 10	31-097-23930-00-00	4/6/2009	Dix (Schuyler)	Gross Alpha	10,970 +/- 2,363 pCi/L
				Gross Beta	1,170 +/- 701 pCi/L
				Cesium-137	1.27 +/- 5.17 pCi/L
				Cobalt-60	0.960 +/- 4.49 pCi/L
				Ruthenium-106	14.5 +/- 37.5 pCi/L
				Zirconium-95	15.2 +/- 8.66 pCi/L
				Radium-226	6,125 +/- 1,225 pCi/L
				Radium-228	516 +/- 99.1 pCi/L
				Thorium-228	130 +/- 20.4 pCi/L
				Thorium-230	2.63 +/- 1.39 pCi/L
				Thorium-232	0.444 +/- 0.213 pCi/L
				Uranium-234	0.000 +/- 0.702 pCi/L
				Uranium-235	1.17 +/- 1.39 pCi/L
				Uranium-238	0.389 +/- 1.01 pCi/L

Well	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
WGI 11	31-097-23949-00-00	4/6/2009	Dix (Schuyler)	Gross Alpha	20,750 +/- 4,117 pCi/L
				Gross Beta	2,389 +/- 861 pCi/L
				Cesium-137	4.78 +/- 6.95 pCi/L
				Cobalt-60	-0.919 +/- 5.79 pCi/L
				Ruthenium-106	-19.700 +/- 49.8 pCi/L
				Zirconium-95	9.53 +/- 11.8 pCi/L
				Radium-226	10,160 +/- 2,026 pCi/L
				Radium-228	1,252 +/- 237 pCi/L
				Thorium-228	47.5 +/- 8.64 pCi/L
				Thorium-230	1.55 +/- 1.16 pCi/L
				Thorium-232	-0.141 +/- 0.278 pCi/L
				Uranium-234	0.493 +/- 0.874 pCi/L
				Uranium-235	0.000 +/- 0.540 pCi/L
				Uranium-238	-0.123 +/- 0.172 pCi/L

New York State

DEC

Division of Mineral Resources

Appendix 14

Department of Public Service Environmental Management & Construction Standards and Practices - Pipelines

Draft Supplemental Generic Environmental Impact Statement

ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION

STANDARDS AND PRACTICES

CHECK-OFF LIST: PART III

PIPELINE

New York State

DEC

Division of Mineral Resources

Appendix 15

Hydraulic Fracturing –
15 Statements from Regulatory Officials

Draft Supplemental Generic Environmental Impact Statement

Part A

GWPC's Congressional Testimony

STATEMENT OF
SCOTT KELL
ON BEHALF OF THE
GROUND WATER PROTECTION COUNCIL

HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
WASHINGTON, D.C.
JUNE 4, 2009

Mr. Chairman, thank you for the opportunity to testify today. My name is Scott Kell. I am President of the Ground Water Protection Council (GWPC) and appear here today on its behalf. I am also Deputy Chief of the Ohio Department of Natural Resources Division of Mineral Resources Management. With me today are Mike Paque, Executive Director of the GWPC, Dave Bolin, Assistant Director of the Alabama Oil and Gas Board, and Lori Wrotenbery, Director of the Oklahoma Corporation Commission's Oil and Gas Conservation Division. Within our respective States, we are responsible for implementing the state regulations governing the exploration and development of oil and natural gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority.

The GWPC is a non-profit association of state agencies responsible for environmental safeguards related to ground water. The members of the association consist of state ground water and underground injection control regulators. The GWPC provides a forum through which its state members work with federal scientists and regulators, environmental groups, industry, and other stakeholders to advance protection of ground water resources through development of policy and regulation that is based on sound science. I have included a list of the GWPC Board of Directors in our written submission.

The GWPC understands that our nation's water and energy needs are intertwined, and that demand for both resources is increasing. Smart energy policy will consider and minimize impacts to water resources.

With respect to the protection of water resources, the GWPC recently published two reports of note. The first of these reports is called *Modern Shale Gas Development in the United States: A Primer (http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf)*. The primer discusses the regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources. As you know, there are numerous deep shale gas basins in the United States, which contain trillions of cubic feet of natural gas. The environmentally responsible development of these resources is of critical importance to the energy security of the U.S. Recently, however, there has been concern raised about the methods used to tap these valuable resources. Technologies such as hydraulic fracturing have been characterized as being environmentally risky and inadequately regulated. The primer is designed to provide accurate technical information to assist policy makers in their understanding of these issues.

In recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations.

From the standpoint of the GWPC, the most critical issue is protection of water resources. As such, our goal is to ensure that oil and gas development is managed in a way that does not create unnecessary and unwarranted risks to water. As a state regulatory official, I can assure you that our regulations are focused on this task. This leads me to the second report the GWPC has recently published.

This report, entitled *State Oil and Gas Regulations Designed to Protect Water Resources,* (http://www.gwpc.org/e-library/documents/general/Oil%20and%20Gas%20Regulation%20Report%20Final%20with%20Cover%205-27-2009.pdf) evaluates regulations implemented by state oil and gas regulatory agencies as they relate to the protection of water. To prepare this report, the GWPC reviewed the regulations of the twenty-seven states that, when combined, account for more than 99.8% of all the oil and natural gas extracted in the U.S. annually. To prepare this report, each state's regulatory requirements were studied with respect to their water protection capacity. The study evaluated regulated processes such as well drilling, construction, and plugging, above-ground storage tanks, pits and a number of other topics. The report also contains a statistical analysis of state regulations. As a result of our regulatory review and analysis, the GWPC concluded that state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, hydraulic fracturing, waste handling, and well plugging requirements. While State regulations are generally adequate, the GWPC report makes the following recommendations.

First, a study of effective hydraulic fracturing practices should be considered for the purpose of developing Best Management Practices (BMPs) that can be adjusted to fit the specific conditions of individual states. A one-size-fits-all federal program is not the most effective way to regulate in this area. BMPs related to hydraulic fracturing would assist states and operators in ensuring the safety of the practice. Of special concern are zones in close proximity to underground sources of drinking water, as determined by the state regulatory authority.

Second, the state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time. This process should be expanded, where appropriate, to include state oil and gas programmatic elements not covered by the current state review guidelines. STRONGER is currently convening a stakeholder workgroup to consider drafting guidelines for state regulation of hydraulic fracturing.

Finally, the GWPC concludes that implementation and advancement of electronic data management systems has enhanced state regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental, or water related data. States should continue to develop comprehensive electronic data management systems and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

In conclusion, Mr. Chairman and Committee Members, we believe that state regulations are designed to provide the level of water protection needed to assure water resources remain both viable and available. The states are continuously striving to improve both the regulatory language and the programmatic tools used to implement that language. In this regard, the GWPC will continue to assist states with their regulatory needs for the purpose of protecting water, our most vital natural resource.

Thank you.

DISCLOSURE REQUIREMENT
Required by House Rule XI, clause 2(g)
and Rules of the Committee on Resources

1. Name: **Scott R. Kell**

2. Business Address: **2045 Morse Rd., Columbus, OH 43229-6605**

3. Business Phone Number: **614-265-7058**

4. Organization you are representing: **The Ground Water Protection Council**

5. Any training or educational certificates, diplomas or degrees or other educational experiences which add to your qualifications to testify on or knowledge of the subject matter of the hearing: **Bachelor's Degree in Geology from Mount Union College and a Masters Degree in Geology from Kent State University.**

6. Any professional licenses, certifications, or affiliations held which are relevant to your qualifications to testify on or knowledge of the subject matter of the hearing:

7. Any employment, occupation, ownership in a firm or business, or work-related experiences which relate to your qualifications to testify on or knowledge of the subject matter of the hearing:

8. Any offices, elected positions, or representational capacity held in the organization on whose behalf you are testifying: **Chief of the Ohio Department of Natural Resources, Division of Mineral Resources Management; President of the Ground Water Protection Council**

9. Any federal grants or contracts (including subgrants or subcontracts) from the Department of the Interior (and /or other agencies invited) which **you** have received in the last three years, including the source and the amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

10. Any federal grants or contracts (including subgrants or subcontracts) the Department of the Interior (and /or other agencies invited) which were received in the last three years by the **organization(s) which you represent** at this hearing, including the source and amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

11. Any other information you wish to convey which might aid the members of the Committee to better understand the context of your testimony:

GWPC Board of Directors

Attachment 1 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

State Oil and Natural Gas Regulations Designed to Protect Water Resources

EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. A web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

Key Messages and Suggested Actions:

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc…)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

Modern Shale Gas Development in the United States: A Primer

EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

Ohio Department of Natural Resources

TED STRICKLAND, GOVERNOR

SEAN D. LOGAN, DIRECTOR

John F. Husted, Chief
Division of Mineral Resources Management
2045 Morse Road, Building H-3
Columbus, OH 43229-6693
Phone: (614) 265-6633 Fax: (614) 265-7999

May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a defective primary cement job on the production casing, which was further complicated by operator error. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection
Rachel Carson State Office Building
P.O. Box 8555
Harrisburg, PA 17105-8555
June 1, 2009

Bureau of Watershed Management 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

Oil Conservation Division
1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3440 • Fax (505) 476-3462 • www.emnrd.state.nm.us/OCD

STATE OIL AND GAS BOARD OF ALABAMA

420 Hackberry Lane
P.O. Box 869999
Tuscaloosa, Alabama 35486-6999
Phone (205)349-2852
Fax (205)349-2861
www.ogb.state.al.us

Berry H. (Nick) Tew, Jr.
Oil and Gas Supervisor

May 27, 2009

Mr. Michel Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mr. Paque:

This letter is in response to your recent inquiry regarding any cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in Alabama. I can state with authority that there have been no documented cases of drinking water contamination caused by such hydraulic fracturing operations in our State.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945, pursuant to its legislative mandates.

The point to be made here is that the State of Alabama has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect those sources from all oil and gas operations. The fact that there has been no documented case of contamination from these operations, to include hydraulic fracturing, is a testament to the proactive regulation of the industry by the Board. Additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

If we can be of further assistance in this matter, please let me know.

Sincerely,

David E. Bolin

David E. Bolin
Deputy Director

RAILROAD COMMISSION OF TEXAS

CHAIRMAN VICTOR G. CARRILLO

May 29, 2009

Mike Paque, Executive Director
Ground Water Protection Agency
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Re: Hydraulic Fracturing of Gas Wells in Texas

Dear Mr. Paque:

I am pleased that representatives of the Ground Water Protection Council will be appearing before the U.S. House Committee on Natural Resources next week on the issue of hydraulic fracturing. I was asked to participate but had a longstanding commitment to tour energy projects in Canada that prevented me from personally participating.

I sincerely hope that you will clear up the misconception that there are "thousands" of contamination cases in Texas and other states resulting from hydraulic fracturing. The Railroad Commission of Texas is the chief regulatory agency over oil and gas activities in this state. Though hydraulic fracturing has been used for over 50 years in Texas, our records do not indicate a single documented contamination case associated with hydraulic fracturing.

The Texas Groundwater Protection Committee (TGPC) tracks groundwater pollution in Texas. All Texas water protection agencies, including the Railroad Commission, are members. Each year, the TGPC publishes a Joint Groundwater Monitoring and Contamination Report, which can be found at http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/sfr/056_07_index.html. The 2007 report cites a total of 354 active groundwater cases attributed to oil and gas activity – this in a state with over 255,000 active oil and gas wells. The majority of these cases are associated with previous practices that are no longer allowed, or result from activity now prohibited by our existing regulations. A few cases were due to blowouts that primarily occur during drilling activity. *Not one of these cases was caused by hydraulic fracturing activity.*

Hydraulic fracturing plays a key role in the development of virtually all unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed (and hydraulically fractured) in the Barnett Shale reservoir, one of the nation's most active and largest natural gas fields. Since 2000, over five trillion cubic feet of gas has been produced from this one reservoir and the Barnett Shale production currently contributes over 20% of Texas' total natural gas production. While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 trillion cubic feet, recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing groundwater contamination in the Barnett Shale play.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

vg Carrillo

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

Part B

IOGCC's Statements from Oil & Gas Regulators from 12 Member States

REGULATORY STATEMENTS ON HYDRAULIC FRACTURING
SUBMITTED BY THE STATES
JUNE 2009

The following statements were issued by state regulators for the record related to hydraulic fracturing in their states. Statements have been compiled for this document.

ALABAMA:

Nick Tew, Ph.D., P.G.
Alabama State Geologist & Oil and Gas Supervisor
President, Association of American State Geologists

There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board of Alabama's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that is, the protection of underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, which include the regulation and approval of hydraulic fracturing operations, have been continuously and actively implemented since the Board was established in 1945, pursuant to its mission and legislative mandates.

The State of Alabama, acting through the Board, has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect these sources from all oil and gas operations, including hydraulic fracturing. The fact that there has been no documented case of contamination from these operations, including hydraulic fracturing, is strong evidence of effective regulation of the industry by the Board. In our view, additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

ALASKA:

Cathy Foerster
Commissioner
Alaska Oil and Gas Conservation Commission

There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.

State regulations already exist in Alaska to protect fresh water sources. Current well construction standards used in Alaska (as required by Alaska Oil and Gas Conservation Commission statutes and regulations) properly protect fresh drinking waters. Surface casing is always set well below fresh waters and cemented to surface. This includes both injectors and producers as the casing/cementing programs are essentially the same in both types of wells. There are additional casings installed in wells as well as tubing which ultimately connects the reservoir to the surface. The AOGCC requires rigorous testing to demonstrate the effectiveness of these barriers protecting fresh water sources.

By passing this legislation [FRAC Act] it is probable that every oil and gas well within the State of Alaska will come under EPA jurisdiction. EPA will then likely set redundant construction guidelines and testing standards that will merely create duplicate reporting and testing requirements with no benefit to the environment. Additional government employees will be required to monitor the programs, causing further waste of taxpayer dollars.

Material safety data sheets for all materials used in oil and gas operations are required to be maintained on location by Hazard Communication Standards of OSHA. Therefore, requiring such data in the FRAC bill is, again, merely duplicate effort with and accomplishes nothing new.

COLORADO:

David Neslin
Director
Colorado Oil and Gas Conservation Commission

To the knowledge of the Colorado Oil and Gas Conservation Commission staff, there has been no verified instance of harm to groundwater caused by hydraulic fracturing in Colorado.

INDIANA:

Herschel McDivitt
Director
Indiana Department of Natural Resources

There have been no instances where the Division of Oil and Gas has verified that harm to groundwater has ever been found to be the result of hydraulic fracturing in Indiana. In fact, we are unaware of any allegations that hydraulic fracturing may be the cause of or may have been a contributing factor to an adverse impact to groundwater in Indiana.

The Division of Oil and Gas is the sole agency responsible for overseeing all aspects of oil and gas production operations as directed under Indiana’s Oil and Gas Act. Additionally, the Division of Oil and Gas has been granted primacy by the U.S. Environmental Protection Agency, to implement the Underground Injection Control (UIC) Program for Class II wells in Indiana under the Safe Drinking Water Act.

KENTUCKY:

Kim Collings, EEC
Director
Kentucky Division of Oil and Gas

In Kentucky, there have been alleged contaminations from citizen complaints but nothing that can be substantiated, in every case the well had surface casing cemented to surface and production casing cemented.

LOUISIANA:

James Welsh
Commissioner of Conservation
Louisiana Department of Natural Resources

The Louisiana Office of Conservation is unaware of any instance of harm to groundwater in the State of Louisiana caused by the practice of hydraulic fracturing. My office is statutorily responsible for regulation of the oil and gas industry in Louisiana, including completion technology such as hydraulic fracturing, underground injection and disposal of oilfield waste operations, and management of the major aquifers in the State of Louisiana.

MICHIGAN:

Harold Fitch
Director, Office of Geological Survey
Department of Environmental Quality

My agency, the Office of Geological Survey (OGS) of the Department of Environmental Quality, regulates oil and gas exploration and production in Michigan. The OGS issues permits for oil and gas wells and monitors all aspects of well drilling, completion, production, and plugging operations, including hydraulic fracturing.

Hydraulic fracturing has been utilized extensively for many years in Michigan, in both deep formations and in the relatively shallow Antrim Shale formation. There are about 9,900 Antrim wells in Michigan producing natural gas at depths of 500 to 2000 feet. Hydraulic fracturing has been used in virtually every Antrim well.

There is no indication that hydraulic fracturing has ever caused damage to ground water or other resources in Michigan. In fact, the OGS has never received a complaint or allegation that hydraulic fracturing has impacted groundwater in any way.

OKLAHOMA:

Lori Wrotenbery
Director, Oil and Gas Conservation Division
Oklahoma Corporation Commission

You asked whether there has been a verified instance of harm to groundwater in our state from the practice of hydraulic fracturing. The answer in no. We have no documentation of such an instance. Furthermore, I have consulted the senior staffs of our Pollution Abatement Department, Field Operations Department, and Technical Services Department, and they have no recollection of having ever received a report, complaint, or allegation of such an instance. We also contacted the senior staffs of the Oklahoma Department of Environmental Quality, who likewise, have no such knowledge or information.

While there have been incidents of groundwater contamination associated with oil and gas drilling and production operations in the State of Oklahoma, none of the documented incidents have been associated with hydraulic fracturing. Our agency has been regulating oil and gas drilling and production operations in the state for over 90 years. Tens of thousands of hydraulic fracturing operations have been conducted in the state in the last 60 years. Had hydraulic fracturing caused harm to groundwater in our state in anything other than a rare and isolated instance, we are confident that we would have identified that harm in the course of our surveillance of drilling and production practices and our investigation of groundwater contamination incidents.

TENNESSEE:

Paul Schmierbach
Manager
Tennessee Department of Environmental Conservation

We have had no reports of well damage due to fracking.

TEXAS:

Victor G. Carrillo
Chairman
Railroad Commission of Texas

The practice of reservoir stimulation by hydraulic fracturing has been used safely in Texas for over six decades in tens of thousands of wells across the state.

Recently in his introductory Statement for the Record (June 9, 2009) of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, Senator Robert Casey stated:

> "Now, the oil and gas industry would have you believe that there is no threat to drinking water from hydraulic fracturing. But the fact is we are already seeing cases in Pennsylvania, Colorado, Virginia, West Virginia, Alabama, Wyoming, Ohio, Arkansas, Utah, Texas, and New Mexico where residents have become ill or groundwater has become contaminated after hydraulic fracturing operations began in the area."

This statement perpetuates the misconception that there are many surface or groundwater contamination cases in Texas and other states due to hydraulic fracturing. This is not true and here are the facts: Though hydraulic fracturing has been used for over 60 years in Texas, our Railroad Commission records ***do not reflect a single documented surface or groundwater contamination case associated with hydraulic fracturing***.

Hydraulic fracturing plays a key role in the development of unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed - and hydraulically fractured - in the Newark East (Barnett Shale) Field, one of the nation's largest and most active natural gas fields. Since 2000, over 5 Tcf (trillion cubic feet) of gas has been produced from this one reservoir and Barnett Shale production currently contributes over 20% of total Texas natural gas production (over 7 Tcf in 2008 – more than a third of total U.S. marketed production). While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 Tcf, conventional recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing surface or groundwater contamination in the Barnett Shale play.

Regulating oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states, which have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – substantially harming domestic energy security. Congress should maintain the status quo and let the states continue to responsibly regulate oil and gas activities, including hydraulic fracturing.

In summary, I am aware of no verified instance of harm to groundwater in Texas from the decades long practice of hydraulic fracturing.

SOUTH DAKOTA:

Fred Steece
Oil and Gas Supervisor
Department of Environment and Natural Resource

Oil and gas wells have been hydraulically fractured, "fracked," in South Dakota since oil was discovered in 1954 and since gas was discovered in 1970. South Dakota has had rules in place, dating back to the 1940's, that require sufficient surface casing and cement to be installed in wells to protect ground water supplies in the state's oil fields. Producing wells are required to have production casing and cement, and tubing with packers installed. The casing, tubing, and cement are all designed to protect drinking waters of the state as well as to prevent commingling of water and oil and gas in the subsurface. In the 41 years that I have supervised oil and gas exploration, production and development in South Dakota, no documented case of water well or aquifer damage by the fracking of oil or gas wells, has been brought to my attention. Nor am I aware of any such cases before my time.

WYOMING:

Rick Marvel
Engineering Manager
Wyoming Oil and Gas Conservation Commission

Tom Doll
Oil and Gas Commission Supervisor
Wyoming Oil and Gas Conservation Commission

- No documented cases of groundwater contamination from fracture stimulations in Wyoming.

- No documented cases of groundwater contamination from UIC regulated wells in Wyoming.

- Wyoming took primacy over UIC Class II wells in 1982, currently 4,920 Class II wells permitted.

Wyoming's 2008 activity:

- Powder River Basin Coalbed Wells – 1,699 new wells, no fracture stimulation.
- Rawlins Area (deeper) Coalbed Wells – 109 new wells, 100% fracture stimulated.
- Statewide Conventional Gas Wells – 1,316 new wells, 100% fracture stimulated – many wells with multi-zone fracture stimulations in each well bore, some staged and some individual fracture stimulations.
- Statewide Oil Wells – 237 new wells, 75% fracture stimulated.

The Wyoming Oil and Gas Commission Rules and Regulations are specific in requiring the operator receive approval prior to performing hydraulic fracturing treatments. The Rules require the operator to provide detailed information regarding the hydraulic fracturing process, to include the source of water and/or trade name fluids, type of proponents, as well as estimated pump pressures. After the treatment is complete the operator is required to provide actual fracturing data in detail and resulting production results.

Under Chapter 3, Section 8 (c) The Application for Permit to Drill or Deepen (Form 1) states…"information shall also be given relative to the drilling plan, together with any other information which may be required by the Supervisor. Where multiple Applications for Permit to Drill will be sought for several wells proposed to be drilled to the same zone within an area of geologic similarity, approval may be sought from the Supervisor to file a comprehensive drilling plan containing the information required above which will then be referenced on each Application for Permit to Drill." Operators have been informed by Commission staff to include detailed information regarding the hydraulic fraction stimulation process on the Form 1 Application for Permit to Drill.

The Rules also state, in Chapter 3, Section 1 (a) "A written notice of intention to do work or to change plans previously approved on the original APD and/or drilling and completion plan (Chapter 3, Section 8 (c)) must be filed with the Supervisor on the Sundry Notice (Form 4), unless otherwise directed, and must reach the Supervisor and receive his approval before the work is begun. Approval must be sought to acidize, cleanout, flush, fracture, or stimulate a well. The Sundry Notice must include depth to perforations or the openhole interval, the source of water and/or trade name fluids, type proponents, as well as estimated pump pressures. Routine activities that do not affect the integrity of the wellbore or the reservoir, such as pump replacements, do not require a Sundry Notice. The Supervisor may require additional information." Most operators will submit the Sundry Notice Form 4 to provide the specific detail for the hydraulic fracturing treatment even though the general information might have been provided under the Form 1 Application for Permit to Drill.

After the hydraulic fracture treatment is complete, results must be reported to the Supervisor. Chapter 3, Section 12 Well Completion or Recompletion Report and Log (Form 3) state "upon completion or recompletion of a well, stratigraphic test or core hole, or the completion of any remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting a liner, gun perforating, or other similar operations not specifically covered herein, a report on the operation shall be filed with the Supervisor. Such report shall present a detailed account of the work done and the manner in which such work was performed; the daily production of the oil, gas, and water both prior to and after the operation; the size and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation and any other pertinent information of operations which affect the original status of the well and are not specifically covered herein."

New York State

DEC

Division of Mineral Resources

Appendix 16

Applicability of NOx RACT Requirements for Natural Gas Production Facilities

Draft Supplemental Generic Environmental Impact Statement

Applicability of NOx RACT Requirements for Natural Gas Production Facilities

New York State's air regulation Part 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NOx), applies to boilers (furnaces) and internal combustion engines at major sources.

The requirements of Part 227-2 include emission limits, stack testing, and annual tune-ups, among others. Many facilities whose potential to emit (PTE) air pollutants would make them susceptible to NOx RACT requirements can limit, or "cap", their emissions using the limits within the New York State Department of Environmental Conservation's (DEC) Air Emissions Permits applicability thresholds to avoid this regulation.

New York State has two different major source thresholds for NOx RACT and permitting. Downstate (in New York City and Nassau, Suffolk, Westchester, Rockland, and Lower Orange Counties) the major source permitting and NOx RACT requirements apply to facilities with a PTE of 25 tons/yr or more of NOx. For the rest of the state (where the majority of natural gas production facilities are anticipated to be located), the threshold is a PTE of 100 tons/yr or more of NOx.

If the stationary engines at a natural gas production facility exceed the applicability levels or if the PTE at the facility would classify it as a Major NOx source, the following compliance options are available:

1. Develop a NOx RACT compliance plan and apply for a Title V permit.
2. Limit the facility's emissions to remain under the NOx RACT applicability levels by applying for one of two New York State Air Emissions permits, depending on how low emissions can be limited.

The permitting options for facilities that wish to limit, or "cap", their emissions by establishing appropriate permit conditions are described below.

New York State's air regulation Part 201, Permits and Registrations, includes a provision that allows a facility to register if its actual emissions are less than 50% of the applicability thresholds (less than 12.5 tons/yr downstate and less than 50 tons/yr upstate). This permit option is known as "cap by rule" registration.

Part 201 also includes a provision that allows a facility to limit its emissions by obtaining a State Facility Permit, if its actual emissions are above the 50% level but below the applicability level (between 12.5 and 25 tons/yr downstate and between 50 and 100 tons/yr upstate).

If the facility NOx emissions cannot be capped below the applicablity levels, then the facility should immediately develop a NOx RACT compliance plan. This plan should contain the necessary steps (purchase of equipment and controls, installation of equipment, source testing, submittal of permit application, etc.) and projected completion dates required to bring the facility into compliance. This plan is to be submitted to the appropriate DEC Regional Office as soon as possible. In this case the facility would also be subject to Title V, and a Title V air permit application must be prepared and submitted.

New York State

DEC

Division of Mineral Resources

Appendix 17

Applicability of Proposed Revision of 40 CFG Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities

Draft Supplemental Generic Environmental Impact Statement

Applicability of Proposed Revision of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities

This action proposes to revise 40 CFR Part 63, Subpart ZZZZ, in order to address hazardous air pollutants (HAP) emissions from existing stationary reciprocating internal combustion engines (RICE) located at area sources. A major source of HAP emissions is a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. An area source of HAP emissions is a source that is not a major source.

Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on natural gas fired and diesel fired RICE include: 1,1,2,2-tetrachloroethane, 1,3-butadiene, 2,2,4-trimethylpentane, acetaldehyde, acrolein, benzene, chlorobenzene, chloroethane, ethylbenzene, formaldehyde, methanol, methylene chloride, n-hexane, naphthalene, polycyclic aromatic hydrocarbons, polycyclic organic matter, styrene, tetrachloroethane, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and
selenium. Although numerous HAP may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAP are: formaldehyde, acrolein, methanol, and acetaldehyde. EPA is proposing to limit emissions of HAP through emissions standards for formaldehyde for non-emergency four stroke-cycle rich burn (4SRB) engines, and engines less than 50 HP, and through emission standards for carbon monoxide (CO) for all other engines.

The applicable emission standards (at 15% oxygen) or management practices for existing RICE located at area sources are as follows:

Subcategory	Emission standards at 15 percent O2, as applicable, or management practice	
	Except during periods of startup, or malfunction	During periods of startup, or malfunction
Non-Emergency 4SLB* ≥250HP	9 ppmvd CO or 90% CO reduction	95 ppmvd CO.
Non-Emergency 4SLB 50-250HP	Change oil and filter every 500 hours; replace spark plugs every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Change oil and filter every 500 hours; replace spark plugs every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.
Non-Emergency 4SRB ≥50HP**	200 ppbvd formaldehyde or 90% formaldehyde reduction.	2 ppmvd formaldehyde.
Non-Emergency CI >300HP	4 ppmvd CO or 90% CO reduction	40 ppmvd CO.

Non-Emergency CI* 50-300HP**	Change oil and filter every 500 hours; inspect air cleaner every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Change oil and filter every 500 hours; replace spark plugs every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.
Non-Emergency CI <50HP	Change oil and filter every 200 hours; replace spark plugs every 500 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Change oil and filter every 200 hours; replace spark plugs every 500 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.

*4SLB - four stroke-cycle lean burn
**4SRB – four stroke-cycle rich burn
***CI – compression ignition

Fuel Requirements

In addition to emission standards and management practices, certain stationary CI RICE located at existing area sources are subject to fuel requirements. stationary non-emergency diesel-fueled CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at existing area sources must only use diesel fuel meeting the requirements of 40 CFR 80.510(b), which requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

New York State

DEC

Division of Mineral Resources

Appendix 18

Clean Air Act Unique Regulatory Definition of Facility for the Oil and Gas Industry

Draft Supplemental Generic Environmental Impact Statement

Clean Air Act Unique Regulatory Definition of "Facility" for the Oil and Gas Industry

The definition of facility is important for understanding how this rule applies to the oil and gas industry and how emissions are aggregated for major source determination. In many places of the 1990 Clean Air Act Amendments (CAAA), facilities were defined as sites that were contiguous and under common control by a company. However, for the oil and gas industry, this definition could potentially lead to the aggregation of emissions from dehydrators that are a substantial distance apart, since one company often controls large geographic areas. To avoid this unintended consequence, the Environmental Protection Agency developed a unique definition of facility for the oil and gas industry. Key excerpts from the definition are as follows:

"***Facility*** means any grouping of equipment where hydrocarbon liquids are processed, upgraded (i.e., remove impurities or other constituents to meet contact specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For the purpose of major source determination, facility (including a building, structure, or installation) means oil and natural gas production equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment….will typically be located within close proximity to other equipment… Pieces of production equipment located on different…leases, tracts, or sites…shall not be considered part of the same facility. Examples of facilities…include…well sites, satellite tank batteries, central tank batteries, a compressor that transports natural gas to a natural gas processing plant, and natural gas processing plants."

"***Surface-site*** means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which the equipment is physically affixed."

New York State

DEC

Division of Mineral Resources

Appendix 19

Greenhouse Gas
(GHG)
Emissions

Draft Supplemental Generic Environmental Impact Statement

Part A

GHG Tables

GHG Tables

Table GHG-1 – Emission Rates for Well Pad[1]

Emission Source/ Equipment Type	CH_4 EF	CO_2 EF	Units	EF Reference[2]
Fugitive Emissions				
Gas Wells				
Gas Wells	0.014	0.00015	lbs/hr per well	Vol 8, page no. 34, table 4-5
Field Separation Equipment				
Heaters	0.027	0.001	lbs/hr per heater	Vol 8, page no. 34, table 4-5
Separators	0.002	0.00006	lbs/hr per separator	Vol 8, page no. 34, table 4-5
Dehydrators	0.042	0.001	lbs/hr per dehydrator	Vol 8, page no. 34, table 4-5
Meters/Piping	0.017	0.001	lbs/hr per meter	Vol 8, page no. 34, table 4-5
Gathering Compressors				
Large Reciprocating Compressor	29.252	1.037	lbs/hr per compressor	GRI - 96 - Methane Emissions from the Natural Gas Industry, Final Report
Vented and Combusted Emissions				
Normal Operations				
1,775 hp Reciprocating Compressor	not determined	1,404.716	lbs/hr per compressor	6,760 Btu/hp-hr, 2004 API, page no. 4-8
Pneumatic Device Vents	0.664	0.024	lbs/hr per device	Vol 12, page no. 48, table 4-6
Dehydrator Vents	12.725	0.451	lbs/MMscf throughput	Vol 14, page no. 27
Dehydrator Pumps	45.804	1.623	lbs/MMscf throughput	GRI June Final Report
Blowdowns				
Vessel BD	0.00041	0.00001	lbs/hr per vessel	Vol 6, page no. 18, table 4-2
Compressor BD	0.020	0.00071	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Compressor Starts	0.045	0.00158	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Upsets				
Pressure Relief Valves	0.00018	0.00001	lbs/hr per valve	Vol 6, page no. 18, table 4-2

[1] Adapted from Exhibit 2.6.1, ICF Incorporated, LLC. *Technical Assistance for the Draft Supplemental Generic EIS: 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*, Agreement No. 9679, August 2009., pp 34-35.

[2] Unless otherwise noted, all emission factors are from the Gas Research Institute, *Methane Emissions from the Natural Gas Industry*, 1996. Available at: epa.gov/gasstar/tools/related.html.

Table GHG-2 – Drilling Rig Mobilization, Site Preparation and Demobilization – GHG Emissions

	One-Well Project or Ten-Well Pad						
Emissions Source	Vehicle Miles Traveled (VMT) In-State Sourcing/Out-of-State Sourcing		Total Operating Hours	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Transportation [3]	1,800 – 3,500	36,000 – 70,000	NA	NA	3 – 6	58 – 112	NA
Drill Pad and Road Construction [4]	NA		48 hours	NA	11		NA
Total Emissions	NA		NA	NA	14 – 17	69 – 123	NA

Table GHG-3 – Completion Rig Mobilization and Demobilization – GHG Emissions

	One-Well Project or Ten-Well Pad					
Emissions Source	Vehicle Miles Traveled (VMT) In-State Sourcing/Out-of-State Sourcing		Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Completion Rig 15 Truckloads[5]	300	6,000	NA	1	10	NA
Total Emissions	NA	NA	NA	1	10	NA

[3] Transportation includes Drill Pad and Road Construction Equipment 10 – 45 Truckloads, Drilling Rig 30 Truckloads, Drilling Fluid and Materials 25 – 50 Truckloads, Drilling Equipment (casing, drill pipe, etc.) 25 – 50 Truckloads. Transportation estimates taken from NTC Consultants, 2009. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, p. 13.

[4] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

[5] NTC Consultants, August 2009. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, p. 13

Table GHG-4 – Well Drilling – GHG Emissions

	One-Well Project					Ten-Well Pad				
Emissions Source	Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions (tons CO_2)	Fugitive Emissions (tons CH_4)	Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions (tons CO_2)	Fugitive Emissions (tons CH_4)
Power Engines[6]	168 hours	1	NA	94	NA	1680 hours	1	NA	940	NA
Circulating System[7]	168 hours	1	negligible	NA	negligible	1680 hours	1	negligible	NA	negligible
Well Control System[8]	As needed	1	negligible	negligible	negligible	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	negligible	94	negligible	NA	NA	negligible	940	negligible

6 Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

7 Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.

8 Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-5 – Well Completion – One-Well Project GHG Emissions

	One-Well Project								
Emissions Source	Vehicle Miles Traveled (VMT) In-State Sourcing/Out-of-State Sourcing		Total Operating Hours or Fuel Use	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Transportation[9]	15,740 – 23,040	314,800 – 460,800[10]	NA	1	NA	25 – 37	504 – 737	NA
Hydraulic Fracturing Pump Engines	NA		29,000 gallons[11]	1	NA	325		NA
Line Heater	NA		72 hours	1	NA	negligible		NA
Flowback Pits/Tanks	NA		72 hours	1	NA	NA		negligible
Flare Stack	NA		72 hours	1	4[12]	576[13]		NA
Rig Engines[14]	NA		24 hours	1	NA	7		NA
Site Reclamation[15]	NA		24 hours	NA	NA	6		NA
Total Emissions	NA		NA	NA	4	939 – 951	1,418 – 1,651	negligible

[9] Transportation includes Completion Fluid and Materials 10 – 20 Truckloads, Completion Equipment (pipe, wellhead) 5 Truckloads, Hydraulic Fracture Equipment (pump trucks, tanks) 150 – 200 Truckloads, Hydraulic Fracture Water 400 – 600 Tanker Trucks, Hydraulic Fracture Sand 20 – 25 Trucks, Flow Back Water Removal 200 – 300 Truckloads,
Site Reclamation Equipment 2 Truckloads. Transportation estimates taken from NTC Consultants, 2009. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, p. 13.

[10] For illustration purposes, VMT includes out-of state sourcing for all materials including water necessary for hydraulic fracturing. Water required for fracturing more likely to be sourced as close to well pad as possible. Analysis assumes no reuse of flowback fluid.

[11] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10.

[12] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, August 2009, NYSERDA Agreement No. 9679. p. 28.

[13] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, August 2009, NYSERDA Agreement No. 9679. p. 28.

[14] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

[15] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

Table GHG-6 – Well Completion – Ten-Well Pad GHG Emissions

	Ten-Well Pad							
Emissions Source	Vehicle Miles Traveled (VMT) In-state Sourcing/Out-of-state Sourcing		Total Operating Hours or Fuel Use	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Transportation[16]	130,040 – 194,040	2,600,800 – 3,880,800[17]	NA	NA	NA	208 – 310	4,161 – 6,209	NA
Hydraulic Fracturing Pump Engines	NA		290,000 gallons	NA	NA	3,250		NA
Line Heater	NA		72 hours	1	NA	negligible		NA
Flowback Pits/Tanks	NA		72 hours	1	NA	NA		negligible
Flare Stack	NA		720 hours	1	40	5,760		NA
Rig Engines[18]	NA		240 hours	1	NA	70		NA
Site Reclamation[19]	NA		24 hours	NA	NA	6		NA
Total Emissions	NA		NA	NA	40	9,294 – 9,396	13,247 – 15,295	negligible

[16] Transportation includes Completion Fluid and Materials 10 – 20 Truckloads, Completion Equipment (pipe, wellhead) 5 Truckloads, Hydraulic Fracture Equipment (pump trucks, tanks) 150 – 200 Truckloads, Hydraulic Fracture Water 400 – 600 Tanker Trucks, Hydraulic Fracture Sand 20 – 25 Trucks, Flow Back Water Removal 200 – 300 Truckloads, Site Reclamation Equipment 2 Truckloads. Transportation estimates taken from NTC Consultants, 2009. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, p. 13.

[17] For illustration purposes, VMT includes out-of state sourcing for all materials including water necessary for hydraulic fracturing. Water required for fracturing more likely to be sourced as close to well pad as possible. Analysis assumes no reuse of flowback fluid.

[18] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

[19] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

Table GHG-7 – First-Year Well Production – One-Well Project GHG Emissions[20]

	One-Well Project							
Emissions Source	Vehicle Miles Traveled (VMT) In-state Sourcing/Out-of-state Sourcing		Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Production Equipment 5 – 10 Truckloads	100 - 200	2,000 – 4,000	NA	NA	NA	1	3 – 6	NA
Wellhead	NA		7,896 hours[21]	1	NA	NA		negligible
Compressor	NA		7,896 hours	1	not determined	5,546[22] (&4[23])		117[24]
Line Heater	NA		7,896 hours	1	negligible	negligible		negligible
Separator	NA		7,896 hours		NA	negligible		negligible
Glycol Dehydrator	NA		7,896 hours	1	negligible	negligible		negligible
Dehydrator Vents	NA		7,896 hours	1	21[25]	3[26]		negligible
Dehydrator Pumps	NA		7,896 hours	1	76[27]	NA		negligible
Pneumatic Device Vents	NA		7,896 hours	3	8[28]	NA		negligible
Meters/Piping	NA		7,896 hours	1	NA	NA		negligible
Vessel BD	NA		4 hours	4	negligible	NA		negligible
Compressor BD	NA		4 hours	4	negligible	NA		negligible
Compressor Starts	NA		4 hours	4	negligible	NA		negligible
Pressure Relief Valves	NA		4 hours	5	negligible	NA		negligible
Production Brine Tanks	NA		7,896 hours	1	negligible	NA		negligible
Production Brine Removal 44Truckloads	880	17,600	NA	NA	NA	2	28	NA
Total Emissions	NA		NA	NA	105	5,556	5,584 – 5,587	117

20 First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
21 Calculated by subtracting total time required to drill and complete one well (36 days) from 365 days.
22 Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
23 Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
24 One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
25 Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
26 Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
27 Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
28 Emissions Factor (EF) of 0.664 lbs per hour.

Table GHG-8 – Post-First Year Annual Well Production – One-Well Project GHG Emissions[29]

	One-Well Project							
Emissions Source	Vehicle Miles Traveled (VMT) In-state Sourcing/Out-of-state Sourcing		Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Wellhead	NA		8,760 hours	1	NA	NA		negligible
Compressor	NA		8,760 hours	1	not determined	6,153[30] (&5[31])		128[32]
Line Heater	NA		8,760 hours	1	negligible	negligible		negligible
Separator	NA		8,760 hours		NA	negligible		negligible
Glycol Dehydrator	NA		8,760 hours	1	negligible	negligible		negligible
Dehydrator Vents	NA		8,760 hours	1	23[33]	3[34]		negligible
Pneumatic Device Vents	NA		8,760 hours	3	9[35]	NA		negligible
Dehydrator Pumps	NA		8,760 hours	1	84[36]	NA		negligible
Meters/Piping	NA		8,760 hours	1	NA	NA		negligible
Vessel BD	NA		4 hours	4	negligible	NA		negligible
Compressor BD	NA		4 hours	4	negligible	NA		negligible
Compressor Starts	NA		4 hours	4	negligible	NA		negligible
Pressure Relief Valves	NA		4 hours	5	negligible	NA		negligible
Production Brine Tanks	NA		8,760 hours	1	negligible	NA		negligible
Production Brine Removal 48 Truckloads	960	19,200	NA	NA	NA	2	31	NA
Total Emissions	NA		NA	NA	116	6,163	6,202	128

29 Assumed production 10 mmcfd per well.
30 Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
31 Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
32 Emissions Factor (EF) of 29.252 lbs per hour.
33 Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
34 Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
35 Emissions Factor (EF) of 0.664 lbs per hour.
36 Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.

Table GHG-9 – First-Year Well Production – Ten-Well Pad GHG Emissions[37]

	Ten-Well Pad								
Emissions Source	Vehicle Miles Traveled (VMT) In-state Sourcing/Out-of-state Sourcing		Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Production Equipment 5 – 10 Truckloads	100 – 200	2,000 – 4,000	NA	NA	NA	1	3 – 6	NA
Wellhead	NA		120 hours[38]	10	NA	NA		
Compressor	NA		120 hours	3	not determined	253[39] (&1[40])		6[41]
Line Heater	NA		120 hours	3	negligible	negligible		negligible
Separator	NA		120 hours	3	NA	negligible		negligible
Glycol Dehydrator	NA		120 hours	2	negligible	negligible		negligible
Dehydrator Vents	NA		120 hours	1[42]	4[43]	1[44]		negligible
Dehydrator Pumps	NA		120 hours	1[45]	9[46]	NA		negligible
Pneumatic Device Vents	NA		120 hours	6	1[47]	NA		negligible
Meters/Piping	NA		120 hours	1	NA	NA		negligible
Vessel BD	NA		2 hours	9	negligible	NA		negligible
Compressor BD	NA		2 hours	4	negligible	NA		negligible
Compressor Starts	NA		2 hours	4	negligible	NA		negligible
Pressure Relief Valves	NA		2 hours	19	negligible	NA		negligible
Production Brine Tanks	NA		120 hours	2	negligible	NA		negligible
Production Brine Removal 40 Truckloads	NA		NA	NA	NA	NA		NA
Total Emissions	NA		NA	NA	14	256	258 – 261	6

[37] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[38] Calculated by subtracting total time required to drill and complete ten wells (360 days) from 365 days.
[39] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[40] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[41] Emissions Factor (EF) of 29.252 lbs per hour.
[42] Emissions Factor (EF) based on throughput, not number of units.
[43] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[44] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[45] Emissions Factor (EF) based on throughput, not number of units.
[46] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[47] Emissions Factor (EF) of 0.664 lbs per hour.

Table GHG-10 – Post-First Year Annual Well Production – Ten-Well Pad GHG Emissions[48]

	Ten-Well Pad							
Emissions Source	Vehicle Miles Traveled (VMT) In-state Sourcing/Out-of-state Sourcing		Total Operating Hours	Activity Factor	Vented Emissions (tons CH_4)	Combustion Emissions In-State Sourcing/Out-of-State Sourcing (tons CO_2)		Fugitive Emissions (tons CH_4)
Wellhead	NA		8,760 hours	10	NA	NA		negligible
Compressor	NA		8,760 hours	3	not determined	18,458[49] (&14[50])		384[51]
Line Heater	NA		8,760 hours	3	negligible	negligible		negligible
Separator	NA		8,760 hours	3	NA	negligible		negligible
Glycol Dehydrator	NA		8,760 hours	2	negligible	negligible		negligible
Dehydrator Vents	NA		8,760 hours	1[52]	232[53]	negligible		negligible
Pneumatic Device Vents	NA		8,760 hours	6	18[54]	NA		negligible
Dehydrator Pumps	NA		8,760 hours	1[55]	836[56]	297[57]		negligible
Meters/Piping	NA		8,760 hours	1	NA	NA		negligible
Vessel BD	NA		4 hours	9	negligible	NA		negligible
Compressor BD	NA		4 hours	4	negligible	NA		negligible
Compressor Starts	NA		4 hours	4	negligible	NA		negligible
Pressure Relief Valves	NA		4 hours	19	negligible	NA		negligible
Production Brine Tanks	NA		8,760 hours	2	negligible	NA		negligible
Production Brine Removal 480 Truckloads	9,600	192,000	NA	NA	NA	15	307	NA
Total Emissions	NA		NA	NA	1,086	18,784	19,076	384

[48] Assumed production 10 mmcfd per well.
[49] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[50] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[51] Emissions Factor (EF) of 29.252 lbs per hour.
[52] Emissions Factor (EF) based on throughput, not number of units.
[53] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[54] Emissions Factor (EF) of 0.664 lbs per hour.
[55] Emissions Factor (EF) based on throughput, not number of units.
[56] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[57] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.

Table GHG-11 – Estimated First-Year Green House Gas Emissions from One-Well Project

	In-state Sourcing vs. Out-of-state Sourcing					
	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[58]	Total Emissions from Proposed Activity CO_2e (tons)	
Drilling Rig Mobilization, Site Preparation and Demobilization	14 –17	69 - 123	NA	NA	14 – 17	69 – 123
Completion Rig Mobilization and Demobilization	1	10	NA	NA	1	10
Well Drilling	94		negligible	negligible	94	
Well Completion including Hydraulic Fracturing and Flowback	939 – 951	1,418 – 1,651	4	100	1,039 – 1,051	1,518 – 1,751
Well Production	5,556	5,584 – 5,587	222	3,650	9,206	9,234 – 9,237
Total	6,604 – 6,619	7,175 – 7,465	226	5,650	12,254 – 12,269	12,825 – 13,115

Table GHG-12 – Estimated Post First-Year Annual Green House Gas Emissions from One-Well Project

	In-state Sourcing vs. Out-of-state Sourcing					
	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[59]	Total Emissions from Proposed Activity CO_2e (tons)	
Well Production Total	6,163	6,202	244	6,100	12,263	12,302

[58] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[59] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Table GHG-13 – Estimated First-Year Green House Gas Emissions from Ten-Well Pad

	In-state Sourcing vs. Out-of-state Sourcing					
	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[60]	Total Emissions from Proposed Activity CO_2e (tons)	
Drilling Rig Mobilization, Site Preparation and Demobilization	14 – 17	69 – 123	NA	NA	14 – 17	69 – 123
Completion Rig Mobilization and Demobilization	1	10	NA	NA	1	10
Well Drilling	940		negligible	negligible	940	
Well Completion including Hydraulic Fracturing and Flowback	9,294 – 9,396	13,247 – 15,295	40	1,000	10,294 – 10,396	14,247 – 16,295
Well Production	256	258 – 261	20	500	756	758 – 761
Total	10,505 – 10,610	14,524 – 16,629	60	1,500	12,005 – 12,110	16,024 – 18,129

Table GHG-14 – Estimated Post First-Year Annual Green House Gas Emissions from Ten-Well Pad

	In-state Sourcing vs. Out-of-state Sourcing					
	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[61]	Total Emissions from Proposed Activity CO_2e (tons)	
Well Production Total	18,784	19,076	1,470	36,750	55,534	55,826

[60] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[61] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Part B

Sample Calculations for Combustion Emissions from Mobile Sources

Sample Calculation for Combustion Emissions (CO_2) from Mobile Sources[1]

INPUT DATA: A fleet of heavy-duty (HD) diesel trucks travels 70,000 miles during the year. The trucks are equipped with advance control systems.

CALCULATION METHODOLOGY:

The fuel usage of the fleet is unknown, so the first step in the calculation is to convert from miles traveled to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor of 7 miles/gallon for diesel heavy trucks provided API's Table 4-10.

$$70{,}000 \frac{miles}{project} \times \frac{gallon\ diesel}{7\ miles} = 10{,}000 \frac{gallons\ diesel\ consumed}{project\ move}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in API's Table 4-1. This factor is provided on a heat basis, so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of 5.75×10^6 Btu/bbl (HHV), given in Table 3-5 of this document. Thus, the fuel heat rate is:

$$10{,}000 \frac{gallons}{project\ move} \times \frac{bbl}{42\ gallons} \times \frac{5.75\ x\ 10^6\ Btu}{bbl} = 1{,}369{,}047{,}619 \frac{Btu}{project\ move} (HHV)$$

According to API's Table 4-1, the fuel basis CO_2 emission factor for diesel fuel (diesel oil) is 0.0742 tonne $CO_2/10^6$ Btu (HHV basis).

Therefore, CO_2 emissions are calculated as follows, assuming 100% oxidation of fuel carbon to CO_2:

$$1{,}369{,}047{,}619 \frac{Btu}{project\ move} \times 0.0742 \frac{tonne\ CO2}{10^6} Btu = 101.78 \frac{tonnes\ CO2}{project\ move}$$

To convert tonnes to US short tons:

$$101.78\ tonnes \times 2204.62 \frac{lbs}{tonne} \div 2000 \frac{lbs}{short\ ton} = 112.19\ tons \frac{CO2}{project\ move}$$

---

[1] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-39, 4-40.

New York State

DEC

Division of Mineral Resources

Appendix 20

PROPOSED Pre-Frac Checklist and Certification

Draft Supplemental Generic Environmental Impact Statement

PROPOSED PRE-FRAC CHECKLIST AND CERTIFICATION

Well Name and Number:
(as shown on NYSDEC-issued well permit)

API Number:

Well Owner:

Planned Frac Commencement Date:

Yes	No	
☐	☐	Well drilled, cased and cemented in accordance with well permit, or in accordance with revisions approved by the Regional Mineral Resources Manager on the dates listed below and revised wellbore schematic filed in regional Mineral Resources office.

Approval Date & Brief Description of Approved Revision(s)
(attach additional sheets if necessary)

☐	☐	All depths where fresh water, brine, oil or gas were encountered or circulation was lost during drilling operations are recorded on the attached sheet. Additional sheets are attached which describe how any lost circulation zones were addressed.
☐	☐	Enclosed cement bond log verifies top of cement and effective cement bond at least 500 feet above the top of the formation to be fractured or at least 300 feet into the previous casing string. If intermediate casing was used and not cemented to surface, or if intermediate casing was not used and production casing was not cemented to surface, then provide the date of approval by the Department and a brief description of justification.

Approval Date & Brief Description of Justification
(attach additional sheets if necessary)

☐	☐	If fracturing operations will be performed down casing, then the pre-fracturing pressure test required by permit conditions will be conducted and fracturing operations will only commence if test is successful. Any unsuccessful test will be reported to the Department and remedial measures will be proposed by the operator and must be approved by the Department prior to further operations.
☐	☐	All other information collected while drilling, listed below, verifies that all observed gas zones are isolated by casing and cement and that the well is properly constructed and suitable for high-volume hydraulic fracturing.

Date and Brief Description of Information Collected
(attach additional sheets if necessary)

☐	☐	Fracturing products used will be the same products identified in the well permit application materials or otherwise identified and approved by the Department.

I hereby affirm under penalty of perjury that information provided on this form is true to the best of my knowledge and belief. False statements made herein are punishable as a Class A misdemeanor pursuant to Section 210.45 of the Penal Law.

Printed or Typed Name and Title of Authorized Representative
Signature, Date

INSTRUCTIONS FOR PRE-FRAC CHECKLIST AND CERTIFICATION

The completed and signed form must be received by the appropriate Regional office at least 48 hours prior to the commencement of fracturing operations. The operator may conduct fracturing operations provided 1) all items on the checklist are affirmed by a response of “Yes,” 2) the *Pre-Frac Checklist And Certification* is received by the Department at least 48 hours in advance and 3) all other pre-frac notification requirements are met as specified in permit conditions. **The well owner is prohibited from conducting fracturing operations on the well without additional Department review and approval if a response of “No” is provided to any of the items in the pre-frac checklist.**

SIGNATURE SECTION

Signature Section - The person signing the *Pre-Frac Checklist and Certification* must be authorized to do so by the Organizational Report on file with the Division.

New York State

DEC

Division of Mineral Resources

Appendix 21

Publically Owned Treatment Works (POTWs) With Approved Pretreatment Programs

Draft Supplemental Generic Environmental Impact Statement

Pretreatment Facilities and Associated WWTPs

Region	Pretreatment Program	Facility	SPDES Number
1	Nassau County DPW - this facility is tracked under Cedar Creek in PCS.	Inwood STP Bay Park STP ***Cedar Creek WPCP	NY0026441 NY0026450 NY0026859
	Glen Cove (C)	Glen Cove STP	NY0026620
	Suffolk DPW	Suffolk Co. SD #3 - Southwest	NY0104809
2	New York City DEP	Wards Island WPCP Owls Head WPCP Newtown Creek WPCP Jamaica WPCP North River WPCP 26th Ward WPCP Coney Island WPCP Red Hook WPCP Tallman Island WPCP Bowery Bay WPCP Rockaway WPCP Oakwood Beach WPCP Port Richmond WPCP Hunts Point WPCP	NY0026131 NY0026166 NY0026204 NY0026115 NY0026247 NY0026212 NY0026182 NY0027073 NY0026239 NY0026158 NY0026221 NY0026174 NY0026107 NY0026191
3	Suffern (V)	Suffern	NY0022748
	Orangetown SD #2		NY0026051
	Orange County SD #1	Harriman STP	NY0027901
	Newburgh (C)	Newburgh WPCF	NY0026310
	Westchester County	Blind Brook Mamaroneck New Rochelle Ossining Port Chester Peekskill Yonkers Joint	NY0026719 NY0026701 NY0026697 NY0108324 NY0026786 NY0100803 NY0026689
	Rockland County SD #1		NY0031895
	Poughkeepsie (C)	Poughkeepsie STP	NY0026255
	New Windsor (T)	New Windsor STP	NY0022446
	Beacon (C)	Beacon STP	NY0025976
	Haverstraw Joint Regional Sewer Board	Haverstraw Joint Regional Stp	NY0028533
	Kingston (C)	Kingston (C) WWTF	NY0029351
4	Amsterdam (C)	Amsterdam STP	NY0020290
	Albany County	North WWTF South WWTF	NY0026875 NY0026867
	Schenectady (C)	Schenectady WPCP	NY0020516
	Rennselaer County SD #1	Rennselaer County SD #1	NY0087971
5	Plattsburgh (C)	City of Plattsburgh WPCP	NY0026018
	Glens Falls (C)	Glens Fall (C)	NY0029050
	Gloversville-Johnstown Joint Board		NY0026042
	Saratoga County SD #1		NY0028240

Region	Pretreatment Program	Facility	SPDES Number
6	Little Falls (C)	Little Falls WWTP	NY0022403
	Herkimer County	Herkimer County SD	NY0036528
	Rome (C)	Rome WPCF	NY0030864
	Ogdensburg (C)	City of Ogdensburg WWTP	NY0029831
	Oneida County		NY0025780
	Watertown		NY0025984
7	Auburn (C)	Auburn STP	NY0021903
	Fulton (C)		NY0026301
	Oswego (C)	Westside Wastewater Facility Eastside Wastewater Facility	NY0029106 NY0029114
	Cortland (C)	LeRoy R. Summerson WTF	NY0027561
	Endicott (V)	Endicott WWTF	NY0027669
	Ithaca (C)		NY0026638
	Binghamton-Johnson City		NY0024414
	Onondaga County	Metropolitan Syracuse Baldwinsville/Seneca Knolls Meadowbrook/Limestone Oak Orchard Wetzel Road	NY0027081 NY0030571 NY0027723 NY0030317 NY0027618
8	Canandaigua (C)	Canandaigua STP	NY0025968
	Webster (T)	Walter W. Bradley WPCP	NY0021610
	Monroe County	Frank E VanLare STP Northwest Quadrant STP	NY0028339 NY0028231
	Batavia (C)		NY0026514
	Geneva (C)	Marsh Creek STP	NY0027049
	Newark (V)		NY0029475
	Chemung County	Chemung County SD #1 Chemung County - Elmira Chemung County - Baker Road	NY0036986 NY0035742 NY0246948
9	Middleport (V)	Middleport (V) STP	NY0022331
	North Tonawanda (C)		NY0026280
	Newfane STP (T)		NY0027774
	Erie County Southtowns	Erie County Southtowns Erie County SD #2 - Big Sister	NY0095401 NY0022543
	Niagara County	Niagara County SD #1	NY0027979
	Blasdell (V)	Blasdell	NY0020681
	Buffalo Sewer Authority	Buffalo (C)	NY0028410
	Amherst SD (T)		NY0025950
	Niagara Falls (C)		NY0026336
	Tonawanda (T)	Tonawanda (T) SD #2 WWTP	NY0026395
	Lockport (C)		NY0027057
	Olean STP (C)		NY0027162
	Jamestown STP (C)		NY0027570
	Dunkirk STP (C)		NY0027961

Mini-Pretreatment Facilities

Region	Facility	SPDES Number
3	Arlington WWTP	NY0026271
3	Port Jervis STP	NY0026522
3	Wallkill (T) STP	NY0024422
4	Canajoharie (V) WWTP	NY0023485
4	Colonie (T) Mohawk View WPCP	NY0027758
4	East Greenbush (T) WWTP	NY0026034
4	Hoosick Falls (V) WWTP	NY0024821
4	Hudson (C) STP	NY0022039
4	Montgomery co SD#1 STP	NY0107565
4	Park Guilderland N.E. IND STP	NY0022217
4	Rotterdam (T) SD2 STP	NY0020141
4	Delhi (V) WWTP	NY0020265
4	Hobart (V) WWTP	NY0029254
4	Walton (V) WWTP	NY0027154
7	Canastota (V) WPCP	NY0029807
7	Cayuga Heights (V) WWTP	NY0020958
7	Moravia (V) WWTP	NY0022756
7	Norwich (C) WWTP	NY0021423
7	Oak Orchard STP	NY0030317
7	Oneida (C) STP	NY0026956
7	Owego (T) SD#1	NY0022730
7	Owego WPCP #2	NY0025798
7	Sherburne (V) WWTP	NY0021466
7	Waverly (V) WWTP	NY0031089
7	Wetzel Road WWTP	NY0027618
8	Avon (V) STP	NY0024449
8	Bath (V) WWTP	NY0021431
8	Bloomfield (V) WWTP	NY0024007
8	Clifton Springs (V) WWTP	NY0020311
8	Clyde (V) WWTP	NY0023965
8	Corning (C) WWTP	NY0025721
8	Dundee STP	NY0025445
8	Erwin (T) WWTP	NY0023906
8	Holley (V) WPCP	NY0023256
8	Honeoye Falls (V) WWTP	NY0025259
8	Hornell (C) WPCP	NY0023647
8	Marion STP	NY0031569
8	Ontario (T) STP	NY0027171
8	Seneca Falls (V) WWTP	NY0033308
8	Walworth SD #1	NY0025704
9	Akron (V) WWTP	NY0031003
9	Arcade (V) WWTP	NY0026948
9	Attica (V) WWTP	NY0021849
9	East Aurora (V) STP	NY0028436
9	Gowanda (V)	NY0032093

New York State

DEC

Division of Mineral Resources

Appendix 22

NYSDEC - Division of Water Hydrofracturing Chemical (HFC) Evaluation Requirements for POTWs

Draft Supplemental Generic Environmental Impact Statement

Form HFC (01/09)

NYSDEC - Division of Water

Hydrofracturing Chemical (HFC) Evaluation Requirements for POTWs

Instructions Page

Note: All requested information must be supplied. Incomplete submissions will not be reviewed.

Applicability

The discharge of wastewater from hydrofracturing gas well operations via a POTW requires prior DEC review and authorization. The POTW must notify the DEC in writing of its intent to accept return or production wastewater from hydrofracturing operations, including the submittal of a headworks analysis. As part of this analysis, the quantity and quality of the wastewater must be evaluated. The attached form is designed for use by the permittee and the well driller or operator to provide the information necessary for the Department to evaluate the HFCs to be used and the quality of the return water to be treated. The DEC will review this submittal as part of its review of the headworks analysis and determine whether a formal SPDES permit modification is necessary.

Notification Requirements and Instructions

HFCs: For **each** proposed HFC, the well drilling concern should complete items 1- 10 on the attached *Hydrofracturing Chemical (HFC) Evaluation Data Sheet.* The well drilling concern may alternately have the hydrofracturing chemical manufacturer complete these sections. This alternative method may be necessary because the HFC manufacturer may be reluctant to reveal trade secret product formulations to the driller.[1]

Return and Production Water: For the return and production water, the well drilling concern should complete items 11 – 17 on the attached form, and sign the certification in Item 18.

Certification: The POTW plant operator must sign and date the certification in Item 19 and submit it to the Department as part of its headworks analysis for the proposed discharge. **Fax or Mail the completed form to** the Bureau of Water Permits, 625 Broadway, Albany, NY 12233-3505**.**

Completing Items 10 and 16 (Toxicity Information) - All reported test data must represent tests conducted in accordance with current EPA toxicity testing manuals and that the results are for the appropriate receiving water (i.e. fresh water or salt water).[2] In general, submissions which do not include any toxicity information will not be authorized. Submissions containing incomplete toxicity information will be reviewed using conservative safety factors that may prevent authorization or result in the permit being modified to include routine whole effluent toxicity testing or other monitoring.

Completing Item 17 (Return Water Analysis) – The return and production water shall be sampled for the parameters listed on Table 17, as well as the following pollutant scans: GC/MS Volatile, GC/MS Base/Neutral, GC/MS Acid, and Metals using GFAA. The pollutant scan sampling results should be included as an attachment. Alternately, all sampling results may be submitted in electronic spreadsheet format. All reported test data must represent tests conducted using Department or EPA approved laboratory methods, and analyzed at an ELAP certified laboratory. For Mercury, Method 1631 shall be used. For proposed discharges, testing results from similar wells drilled in the same formation using the same HFCs are acceptable for purposes of analysis. All radioactive isotopes must be identified as part of this analysis, including measurements of radioactivity in picoCuries/liter.

Phosphorus - The permittee must demonstrate that the use and discharge of any HFCs containing phosphorus, tributary to the Great Lakes Basin or other ponded waters, is necessary and that no acceptable alternatives exist. Please note that in some cases your permit may require modification to regulate phosphorus.

(1) If requested, the Department will restrict access to trade secret information to the extent authorized by law.

(2) **Submission of both acute (48 or 96 hour LC50 or EC50) and chronic (NOEC) test results for at least one vertebrate and one invertebrate species are required**. Refer to the following three manuals: EPA/600/4-90/027F (1993); EPA/600/4-91/002 (1994); EPA/600/4-91/003 (1994); or their replacements.

NYSDEC - Division of Water

Hydrofracturing Chemical (HFC) Evaluation Data Sheet

TO BE COMPLETED BY DRILLING CONCERN OR HFC CHEMICAL SUPPLIER

Note: All requested information must be supplied. Incomplete submissions will not be reviewed.

1.a. Facility Name:	1.b. Facility Location:
2.a. Date Signed by Facility:	2.b. Date Signed by HFC Mfr:
3.a. HFC Name:	
3.b. HFC Manufacturer:	
4. HFC Function:	
5. Method of onsite storage:	
6.a. HFC Daily Dosage to well: average lbs/day =	, maximum lbs/day =
7.a. HFC BOD: (lb/lb) -	(mg/l) -
7.b. HFC COD: (lb/lb) -	(mg/l) -
8.a. Is HFC a NYS registered biocide?	8.b. Registration Number -

9.a. HFC Composition - Ingredients/Impurities (note: ingredients/impurities must total to 100%)	9.b. %	9.c. CAS#	9.d. Injection Concentration
			mg/l
			mg/l
			mg/l
			mg/l
			mg/l
			mg/l
			mg/l
			mg/l
			mg/l

10. HFC Toxicity Info (most sensitive species) - Attach description of endpoint for each EC50 and LOEC.

10.a. Vertebrate Species	LC50	EC50	Chronic NOEC	Chronic LOEC	Other -
	mg/l	mg/l	mg/l	mg/l	
10.b. Invertebrate Species	LC50	EC50	Chronic NOEC	Chronic LOEC	Other -
	mg/l	mg/l	mg/l	mg/l	

Form HFC (2/02)

NYSDEC - Division of Water

Hydrofracturing Chemical (HFC) Evaluation Data Sheet

11.a. WWTP Name:			11.b. WWTP Location:		
12. SPDES No.:			13. Return Water Source:		
14.a. Date Signed by WWTP:			14.b. Date Signed by Drilling Co.:		
15.a. Return water flow rate: average GPM = , maximum GPM =					
15.b. Proposed HFC return water loading to WWTP:					
average GPM = , maximum GPM=					
16. Return Water Toxicity (most sensitive species) - Attach description of endpoint for each EC50 and LOEC.					
16.a. Vertebrate Species	LC50	EC50	Chronic NOEC	Chronic LOEC	Other -
	mg/l	mg/l	mg/l	mg/l	
16.b. Invertebrate Species	LC50	EC50	Chronic NOEC	Chronic LOEC	Other -
	mg/l	mg/l	mg/l	mg/l	
17. Return Water Analysis: Complete attached table for all detected analytes.					

18. HFC Manufacturer Certification - I certify under penalty of law that this notification and all attachments are, to the best of my knowledge and belief, true, accurate and complete.

Name:	Signature:
Title and Company:	
Telephone:	Fax:

19. Permittee Certification - I certify under penalty of law that this notification and all attachments are, to the best of my knowledge and belief, true, accurate and complete.

Permittee Name:	2.b. SPDES No.:
Contact Name:	
Signature:	Date:
Telephone:	Fax:

20. NYSDEC Approval:

Name:	Signature:
Title:	Date:
Address:	
Telephone:	Fax:

17. Return Water Analysis: Complete the attached table for all analytes detected, and attach the results from the pollutant scans as listed in the instructions. Alternately, this information may be provided on an Excel spreadsheet listing the information in the table below.

WWTP Name:		HFC Source:				Proposed Start Date:			
SPDES No.: NY		WWTP Loading Rates, in lb/day				Percent Removal		Projected Effluent Quality	
Parameter	Return Water Concentration mg/l	Return Water Loading	Present WWTP Loading	Total WWTP Loading	Permitted WWTP Loading	Present WWTP % Removal	Anticipated WWTP % Removal	Maximum Effluent Loading, lb/day	Maximum Effluent Concentration mg/l
pH, range, SU									
Oil and Grease									
Solids, Total Suspended									
Solids, Total Dissolved									
Chloride									
Sulfate									
Alkalinity, Total (CaCO3)									
BOD, 5 day									
Chemical Oxygen Demand (COD)									
Total Kjeldahl Nitrogen (TKN)									
Ammonia, as N									
Total Organic Carbon									
Phenols, Total									
Radium (sum of all isotopes), pCi/l									
Thorium, pCi/l									
Uranium (sum of all isotopes)									
Gross Alpha Radiation, pCi/l									
Gross Beta Radiation, pCi/l									

Please note that a log listing the date, volume, and source of all wastewater accepted from hydrofracturing activites shall be kept and submitted on a monthly basis as an attachment to the facility’s Discharge Monitoring Report.

New York State

DEC

Division of Mineral Resources

Appendix 23

USEPA Natural Gas STAR Program

Draft Supplemental Generic Environmental Impact Statement

TO: Peter Briggs, New York State Department of Environmental Conservation, Mineral Resources

FROM: Jerome Blackman, Natural Gas STAR International

DATE: September 1, 2009

RE: Natural Gas Star

This memo lists methane emission mitigation options applicable in exploration and production; in reference to your inquiry. Natural Gas STAR Partners have reported a number of voluntary activities to reduce exploration and production methane emissions, and major project types are listed and summarized below and may help focus your research as you review the resources available on the Natural Gas STAR website.

In addition to these practices and technologies is an article that lists the same and several more cost effective options for producers to reduce methane emissions. Please refer to the link below.

Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers
www.epa.gov/gasstar/documents/CaseStudy.pdf

Reduced Emission Completions
Traditionally, "cleaning up" drilled wells, before connecting them to a production sales line, involves producing the well to open pits or tankage where sand, cuttings, and reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Partners reported using a "green completion" method in which tanks, separators, dehydrators are brought on site to clean up the gas sufficiently for delivery to sales. The result is reducing completion emissions, creating an immediate revenue stream, and less solid waste.

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/greencompletions.pdf

BP Experience Presentation with Reduced Emission Completions
www.epa.gov/gasstar/documents/workshops/2008-annual-conf/smith.pdf

Green Completion Presentation from a Tech-Transfer Workshop in 2005 at Houston, TX
www.epa.gov/gasstar/documents/workshops/houston-2005/green_c.pdf

Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrator
In dehydrators, as triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). When the TEG is regenerated through heating, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. Many wells produce gas below the initial design capacity yet

TEG circulation rates remain two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Optimizing circulation rates reduces methane emissions at negligible cost. Installing flash tank separators on glycol dehydrators further reduces methane, VOC, and HAP emissions and saves even more money. Flash tanks can recycle typically vented gas to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_flashtanks3.pdf

Dehydrator Presentation from a 2008 Tech-Transfer Workshop in Charleston, WV:
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/charleston_dehydration.pdf

Replacing Glycol Dehydrators with Desiccant Dehydrators

Natural Gas STAR Partners have found that replacing glycol dehydrators with desiccant dehydrators reduces methane, VOC, and HAP emissions by 99 percent and also reduces operating and maintenance costs. In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. Replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to $9,232 per year in fuel gas, vented gas, operation and maintenance (O&M) costs, and reduce methane emissions by 444 thousand cubic feet (Mcf) per year.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_desde.pdf

Directed Inspection and Maintenance

A directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.

Lessons Learned Documents from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_dimgasproc.pdf
www.epa.gov/gasstar/documents/ll_dimcompstat.pdf

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/conductdimatremotefacilities.pdf

DI&M Presentation from a Tech-Transfer Workshop in 2008 at Midland, TX
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland4.ppt

New York State

DEC

Division of Mineral Resources

Appendix 24

Key Features of USEPA Natural Gas STAR Program

Draft Supplemental Generic Environmental Impact Statement

Key Features of USEPA Natural Gas STAR Program[1]

Complete information on the Natural Gas STAR Program is given in USEPA's web site (http://epa.gov/gasstar/index.html)

- Participation in the program is voluntary.

- Program outreach is provided through the web site, annual national two-day implementation workshop, and sector– or activity – specific technology transfer workshops or webcasts, often with a regional focus (approximately six to nine per year).

- Companies agreeing to join ("Partners") commit to evaluating Best Management Practices (BMP) and implementing them when they are cost-effective for the company. In addition, " …partners are encouraged to identify, implement, and report on other technologies and practices to reduce methane emissions (referred to as Partner Reported Opportunities or PROs)."

- Best Management Practices are a limited set of reduction measures identified at the initiation of the program as widely applicable. PROs subsequently reported by partners have increased the number of reduction measures.

- The program provides calculation tools for estimating emissions reductions for BMPs and PROs, based on the relevant features of the equipment and application.

- Projected emissions reductions for some measures can be estimated accurately and simply; for example, reductions from replacing high-bleed pneumatic devices with low-bleed devices are a simple function of the known bleed rates of the respective devices, and the methane content of the gas. For others, such as those involving inspection and maintenance to detect and repair leaks, emissions reductions are difficult to anticipate because the number and magnitude of leaks is initially unknown or poorly estimated.

- Tools are also provided for estimating the economics of emission reduction measures, as a function of factors such as gas value, capital costs, and operation and maintenance costs.

- Technical feasibility is variable between measures and is often site- or application- specific. For example, in the Gas STAR Lessons Learned for replacing high-bleed with low-bleed pneumatic devices, it is estimated that "nearly all" high-bleed devices can feasibly be replaced with low-bleed devices. Some specific exceptions are listed, including very large valves requiring fast and/or precise response, commonly on large compressor discharge and bypass controllers.

- Partners report emissions reductions annually, but the individual partner reports are confidential. Publicly reported data are aggregated nationally, but include total reductions by sector and by emissions reduction measure.

---

[1] New Mexico Environment Department, *Oil and Gas Greenhouse Gas Emissions Reductions*. December 2007, pp. 19-20.

New York State

DEC

Division of Mineral Resources

Appendix 25

Reduced Emissions Completion (REC) Executive Summary

Draft Supplemental Generic Environmental Impact Statement

Reduced Emissions Completions – Executive Summary[1]

High prices and high demand for natural gas, have seen the natural gas production industry move into development of the more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and methane emissions to the atmosphere (The 40 BCF value is an extension of BP's venting for well-bore deliquification scaled up for the entire basin. It is not due to well clean-up post fracture stimulation).

Conventional completion of wells (a process that cleans the well bore of drill cuttings and fluid and fracture stimulation fluids and solids so that the gas has a free path from the reservoir) resulted in gas being either vented or flared. Vented gas resulted in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions being released to the atmosphere, while flared gas resulted in carbon dioxide emissions.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the completion and process this gas suitably for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of eight different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2005 emissions reductions from RECs have increased from 200 MMcf to over 7,000 MMcf. This represents additional revenue from natural gas sales of over $65 million in 2005 (assuming $7/Mcf gas prices).

Method for Reducing Gas Loss	Volume of Natural Gas Savings (Mcf/yr)[1]	Value of Natural Gas Savings ($/yr)[2]	Additional Savings ($/yr)[3]	Set-up Costs ($/yr)	Equipment Rental and Labor Costs ($)	Other Costs ($/yr)[4]	Payback (Months)[5]
Reduced Emissions Completion	270,000	1,890,000	197,500	15,000	212,500	129,500	3

1. Based on an annual REC program of 25 completions per year
2. Assuming $7/Mcf gas
3. Savings from recovering condensate and gas compressed to lift fluids
4. Cost of gas used to fuel compressor and lift fluids
5. Time required to recover the entire annual cost of the program

[1] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: 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, *Task 2 – Technical Analysis of Potential Impacts to Air*, Agreement No. 9679, August 2009. Appendix 2.1.

New York State

DEC

Division of Mineral Resources

Appendix 26

Instructions for Using The On-Line Searchable Database To Locate Drilling Applications

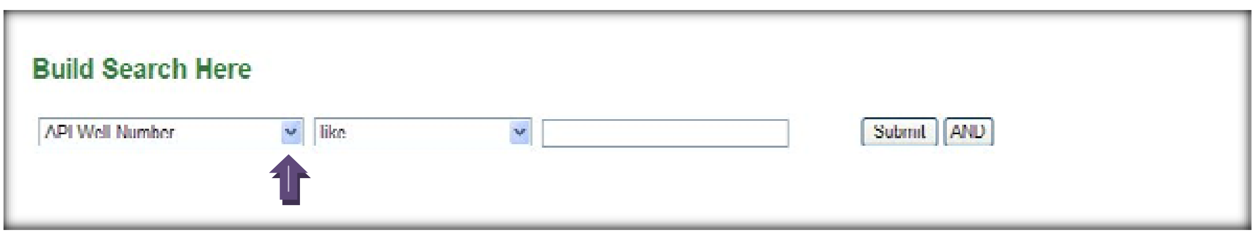
Draft Supplemental Generic Environmental Impact Statement

How to search for a newly applied for permit in the online searchable database

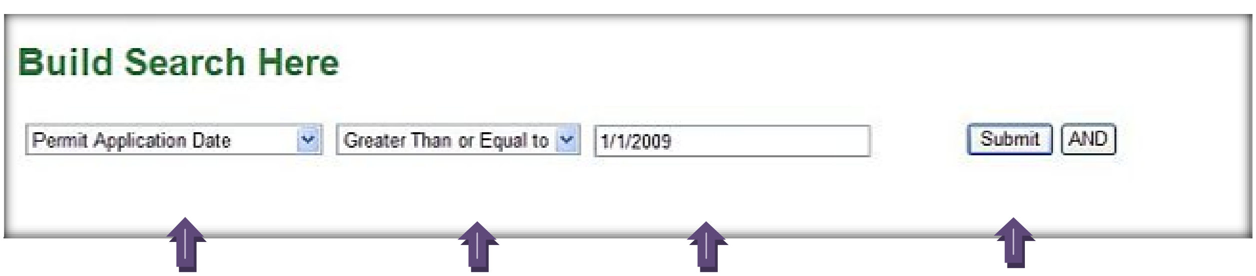
The online searchable database can be found at http://www.dec.ny.gov/cfmx/extapps/GasOil/. It is a very user friendly program and can be used to conduct both simple and complex searches.

1. Select Wells Data to begin your search.

2. Select your search criteria. Use the pull down arrow next to API Number to select your search criteria.



3. To find a new permit application, enter Permit Application Date is Greater Than or Equal to, and the date that you would like to search from. Enter permit application date is Greater Than or Equal to 1/1/year to find all permit applications filed during a specific year. Click the submit button.



4. View results. By selecting the View Map hyperlink a new window will open to Google Maps showing the well location along with latitude and longitude. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) by clicking the appropriate Export button at the bottom of the results screen. Clicking a hyperlink in the Company Name column will provide contact information for the company.

Wells Data Search

Search Parameters [Go Back]

- Permit Application Date Greater Than or Equal to "1/01/2009"

Export XLS | Export CSV | First 50 | Previous 50 | Next 50 | Last 50

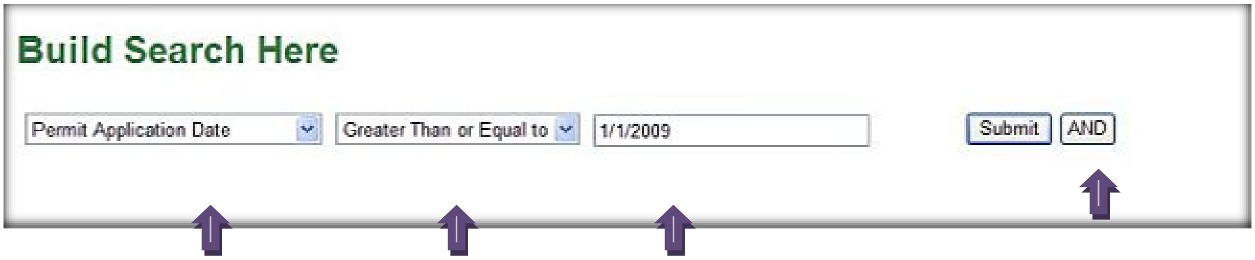
Record Count: 434 Rows: 1 to 10

API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date
31003201168002 View Map	N/A	N/A	N/A	20116	Ryan J 1 SC 190	National Fuel Gas Supply Corp	Confidential	Confidential	Oriskany	Confidential	Allegany	Willing	Wellsville South	H	Confidential	
31003253410001 View Map	N/A	N/A	N/A	25341	Otis Eastern 18	U S Energy Development Corp.	Confidential	Confidential	Upper Devonian	Confidential	Allegany	Andover	Whitesville	B	Confidential	
31003253420001	N/A	N/A	N/A	[illegible]	Otis Eastern	U S Energy Development	[illegible]	[illegible]	Upper	Not	[illegible]	[illegible]	[illegible]	B	Fulmer	

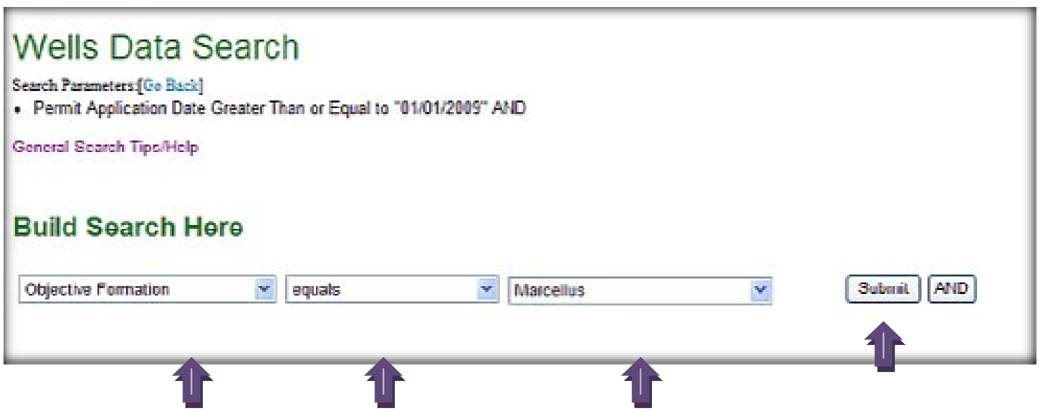
How to search for more specific information utilize the AND button

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all Permits filed in 2009 that target a specific geologic formation, select Permit Application Date is greater than or equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permits applied for in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Hit the Submit button.



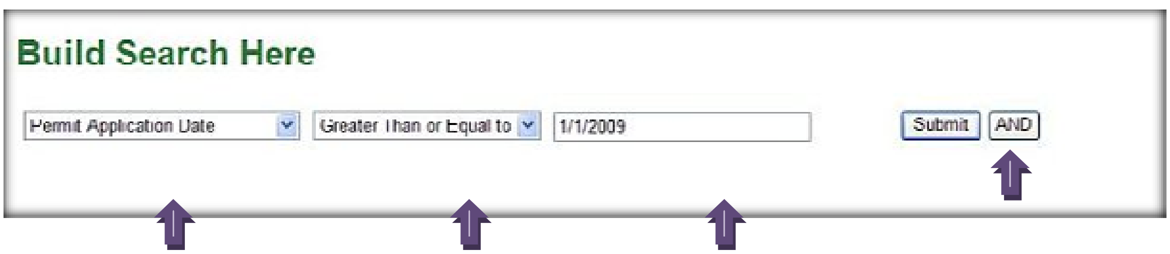
4. View Results.

API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date	Permit Application Date
31007263900000 View Map	N/A	View	N/A	26390	Kark 1H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263910000 View Map	N/A	View	N/A	26391	Kark 2H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263920000 View Map	N/A	View	N/A	26392	Kark 3H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009

How to search by submitted Applications and a specific County

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all Permits filed in 2009 in a specific county, select Permit Application Date is greater than or equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permits applied for in 2009 in Allegany County, select County equals Allegany. Click the Submit button.

Bibliography

[Alpha] Alpha Environmental Consultants Inc. 2009 September. Technical Consulting Reports Prepared in Support of the Draft Supplemental Generic Environmental Impact Statement for Natural Gas Production in New York State. Prepared for NYSERDA, Albany, NY.

ALL Consulting. 2009 August 26. Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emission Data.

[API] American Petroleum Institute. August 2009. Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry. Available at http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf (accessed September 21, 2009)

[API] American Petroleum Institute. 2004, amended 2005. Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry.

[API] American Petroleum Institute and International Petroleum Industry Environmental Conservation Association. 2003 December. Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions.

Camp, Dresser and McKee. 1986.

Center for Climate Strategies. 2006 November. Appendix D--New Mexico Greenhouse Gas Inventory and Reference Case Projections, 1190-2020. Prepared for New Mexico Environment Department. pp. D-35.

Chesapeake Energy Corporation. 2009 July. Greenhouse Gas Emissions and Reductions Fact Sheet.

Colorado Oil and Gas Conservation Commission. 2009. Final Amended Rules; Training Presentations. Available from: http://cogcc.state.co.us (accessed July 8, 2009).

Colorado Oil and Gas Conservation Commission. 2009 March 30. Series Drilling, Development, Production and Abandonment. Available from: http://cogcc.state.co.us/RR_Docs_new/rules/300series.pdf (accessed August 26, 2009).

Considine T, Watson R, Entler R, Sparks J. 2009 August 5. An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play. Prepared for the Marcellus Shale Gas Committee by the Department of Energy and Mineral Engineering, The Pennsylvania State University, p. 2.

Delaware River Basin Commission. 2008 September 12. Administrative Manual Part III--Water Quality Regulations (with amendments through July 16, 2008) 18 CFR Part 410.

Available from: http://www.state.nj.us/drbc/regs/WQRegs_071608.pdf (accessed August 27, 2009).

Delaware River Basin Commission. 2007 August 14. Water Code. 18 CFR Part 410. Available from: http://www.state.nj.us/drbc/regs/watercode_092706.pdf (accessed September 29, 2009).

[ECL] Environmental Conservation Law. (With 2009 Cumulative Pocket Part). c2007 and 2009. Ed. McKinney's Consolidated Laws of New York Annotated--Book 17½. Eagan MN: West. Available from: http://public.leginfo.state.ny.us/menugetf.cgi?COMMONQUERY=LAWS (accessed September 21, 2009).

[EPA] United States Environmental Protection Agency. 2009 September 24. Natural Gas STAR Program. Available at: http://www.epa.gov/gasstar/ (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2009 September 11. Drinking Water Contaminants. Available from: http://www.epa.gov/safewater/contaminants/index.html (accessed September 29, 2009).

[EPA] United States Environmental Protection Agency. 2009 August 28. Filtration Avoidance. Available from: http://www.epa.gov/Region2/water/nycshed/filtad.htm (accessed September 3, 2009).

[EPA] United States Environmental Protection Agency. 2009 August 28. Natural Gas STAR Program--Recommended Technologies and Practices. Available at: http://www.epa.gov/gasstar/tools/recommended.html (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2009 August 27. Drinking Water Contaminants. Available from: http://www.epa.gov/safewater/contaminants/index.html (accessed August 27, 2009).

[EPA] United States Environmental Protection Agency. 2009 May 21. Technology Transfer Network--National Ambient Air Quality Standards (NAAQS). Available from: http://www.epa.gov/ttn/naaqs/ (accessed September 30, 2009).

[EPA] United States Environmental Protection Agency. 2009 February 16. Natural Gas STAR Program--Join the Program. Available from: http://www.epa.gov/gasstar/join/index.html (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2008 October. Your Partner in Improving Operational Efficiency, Saving Money, and Reducing Emissions. Available at http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2007 January 3. Federal Register. Rules and Regulations. Vol. 72, No. 1. Available from: http://www.epa.gov/ttn/atw/oilgas/fr03ja07.pdf (accessed September 2, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Optimize Glycol Circulation and Install Flash Tank Separators In Glycol Dehydrators. Available at: http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. Available at: http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Reducing Emissions When Taking Compressors Offline. Available at: http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Reducing Methane Emissions from Compressor Rod Packing Systems. Available at: http://www.epa.gov/gasstar/documents/ll_rodpack.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Replacing Gas-Assisted Glycol Pumps with Electric Pumps. Available at: http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf (accessed September 22, 2009).

[EPA] United States Environmental Protection Agency. 2006. Lessons Learned From Natural Gas STAR Partners--Replacing Glycol Dehydrators with Desiccant Dehydrators. Available at: http://www.epa.gov/gasstar/documents/ll_desde.pdf (accessed September 22, 2009).

Estes CC. 1998. Annual summary of instream flow reservations and protection in Alaska. Fisheries Data Series No. 98-40. Anchorage: Alaska Department of Fish and Game.

Estes CC. 1984. Evaluation of methods for recommending instream flows to support spawning by salmon. Master’s thesis, Washington State university, Pullman.

[FEMA] United States Department of Homeland Security. FEMA Map Service Center. Available from: http://msc.fema.gov (accessed August 27, 2009).

[GWPC] Ground Water Protection Council. 2009 May. State Oil and Natural Gas Regulations Designed to Protect Water Resources. Prepared for the United States Department of Energy (USDOE). Available at: http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf (accessed September 3, 2009).

[GPWC] Ground Water Protection Council and ALL Consulting. 2009 April. Modern Shale Gas Development in the United States: A Primer. Prepared for United States Department of Energy (USDOE). Available from: http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf (accessed August 28, 2009).

Gas Research Institute. 1996. Methane Emissions from Natural Gas Industry. Available at: epa.gov/gasstar/tools/related.html (accessed September 22, 2009).

Harrison SS. 1983 November. Evaluating System for Groundwater Contamination Hazards due to Gas Well Drilling on the Glaciated Appalachia Plateau. Groundwater 21:6 pp. 689-700.

Hill DG, Lombardi TE, Martin JP. 2003. Fractured Shale Gas Potential in New York. Available at http://www.pe.tamu.edu/wattenbarger/public_html/Selected_papers/--Shale%20Gas/fractured%20shale%20gas%20potential%20in%20new%20york.pdf (accessed September 22, 2009).

[ICF Task 1] ICF Incorporated, LLC. 2009 August 7. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program, Task 1. Prepared for NYSERDA, Albany, NY.

[ICF Task 2] ICF Incorporated, LLC. 2009 August 5. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program, Task 2. Prepared for NYSERDA, Albany, NY.

IFC. 2004.

[IOCGG] Interstate Oil & Gas Compact Commission. 2009. Issues. Available from: http://www.iogcc.state.ok.us/hydraulic-fracturing (accessed August 31, 2009).

[IPCC] International Panel on Climate Change. 2007. Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Solomon S, Qin D, Manning M, Chen Z, Marquis M, Avery KB, Tignor M, and Miller HL, eds.. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Available from: http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf (accessed September 22, 2009).

Lloyd E. 2008 July 18. Letter to Commissioner Alexander B. Grannis, NYSDEC.

New Mexico Environment Department. December 2007. Oil and Gas Greenhouse Gas Emissions Reductions.

New York State Commission on State Asset Maximization. 2009 June. The Final Report of the New York State Commission on Asset Maximization.

New York State Energy Planning Board. 2009 August. Draft New York State Energy Plan.

New York State Invasive Species Task Force. 2005 Fall. Final Report. Available from: http://www.dec.ny.gov/docs/wildlife_pdf/istfreport1105.pdf (accessed September 29, 2009).

New York State Public Service Commission. 2004 August. The Certification Review Process for Major Electric and Fuel Gas Transmission Facilities--Under Article VII of the New York State Public Service Law. Available from: http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf (accessed September 29, 2009).

NTC Consultants. 2009 September. Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs. Prepared for NYSERDA, Albany, NY.

[NYCDEP] New York City Department of Environmental Protection. c2009. Drinking Water Supply and Quality Report. Available from: http://www.nyc.gov/html/dep/html/drinking_water/wsstate.shtml (accessed August 27, 2009).

[NYCDEP] New York City Department of Environmental Protection. c2009. New York City Water Supply Watersheds. Available from: http://www.nyc.gov/html/dep/html/watershed_protection/html/regcontext.html (accessed September 3, 2009).

[NYCDEP] New York State Department of Environmental Protection. March 2009. Title 15 Rules of the City of New York. Section 18-16. Definitions. Available at http://24.97.137.100/nyc/rcny/entered.htm

[NYCDEP] New York City Department of Environmental Protection. c2009. Watershed Rules and Regulations. Available from: http://www.nyc.gov/html/dep/html/watershed_protection/html/regulations.html# (accessed August 31, 2009).

[6 NYCRR] New York Department of State--Division of Administrative Rules. 2009. New York State Compilation of Codes, Rules and Regulations. Thomson Reuters\West. Unofficial version available from: http://www.dos.state.ny.us/info/nycrr.htm (accessed September 8, 2009).

[6 NYCRR] Part 617.20. [undated]. Appendix A--State Environmental Quality Review: Full Environmental Assessment Form. Available from: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/longeaf.pdf (accessed September 3, 2009).

[6 NYCRR] Part 617.20. [undated]. Appendix B--State Environmental Quality Review: Visual EAF Addendum. Available from: http://www.dec.ny.gov/docs/permits_ej_operations_pdf/visualeaf.pdf (accessed September 2, 2009).

[10 NYCRR] New York Department of State--Division of Administrative Rules. 2009. New York State Compilation of Codes, Rules and Regulations. Thomson Reuters\West. Unofficial version available from: http://www.dos.state.ny.us/info/nycrr.htm (accessed September 8, 2009).

[12 NYCRR] New York Department of State--Division of Administrative Rules. 2009. New York State Compilation of Codes, Rules and Regulations. Thomson Reuters\West. Unofficial version available from: http://www.dos.state.ny.us/info/nycrr.htm (accessed September 8, 2009).

[NYSDEC] New York State Department of Environmental Conservation. 2009 July 15. Assessing Energy Use and Greenhouse Gas Emissions in Environmental Impact Statements. Available from: http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation. c2009. Part 601: Water Supply Applications (Exclusive of Long Island Wells). Available from: http://www.dec.ny.gov/regs/4445.html (accessed September 4, 2009).

[NYSDEC] New York State Department of Environmental Conservation. c2009. Part 663: Freshwater Wetlands Permit Requirements. Available from: http://www.dec.ny.gov/regs/4613.html (accessed September 4, 2009).

[NYSDEC] New York State Department of Environmental Conservation. c2009. Part 664: Freshwater Wetlands Maps and Classification. Available from: http://www.dec.ny.gov/regs/4612.html (accessed September 4, 2009).

[NYSDEC] New York State Department of Environmental Conservation. 1992. [GEIS] Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program. Available from: http://www.dec.ny.gov/energy/45912.html (accessed August 27, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Bureau of Hazardous Waste Management. c2009. An Investigation of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Wells in New York State, Executive Summary.

Available from: http://www.dec.ny.gov/chemical/23473.html (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Bureau of Source Control. 1994 September 28. Spill Prevention Operations Technology Series (SPOTS) Memo #10: Secondary Containment Systems for Aboveground Storage Tanks. Available from: http://www.dec.ny.gov/docs/remediation_hudson_pdf/spots10.pdf (accessed September 4, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Bureau of Water Resource Management. c2009. New York City Watershed Program. Available from: http://www.dec.ny.gov/lands/25599.html (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. Ambient Air Quality Monitoring. Available from: http://www.dec.ny.gov/chemical/8406.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. Policy CP-33: Assessing and Mitigating Impacts of Fine Particulate Matter Emissions. Available from: http://www.dec.ny.gov/chemical/8912.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. Policy DAR-1: Guidelines for Control of Toxic Ambient Air Contaminants. Available from: http://www.dec.ny.gov/chemical/30681.html (accessed August 31, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. DAR-1--AGC/SGC Tables and Software Support Files. Available from: http://www.dec.ny.gov/chemical/30560.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. Policy DAR-10: Impact Analysis Modeling. Available from: http://www.dec.ny.gov/chemical/8923.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Air. c2009. State Implementation Plan. Available from: http://www.dec.ny.gov/chemical/8403.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Environmental Permits. c2009. Division of Environmental Permits Policy Documents. Available from: html://www.dec.ny.gov/permits/6224.html (accessed September 2, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Mineral Resources. c2009. Casing and Cementing Practices. Available from: http://www.dec.ny.gov/energy/1757.html (accessed September 2, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Mineral Resources. c2009. Fresh Water Aquifer Supplementary Drilling Conditions. Available from: http://www.dec.ny.gov/energy/42714.html (accessed September 2, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Mineral Resources. c2009. Marcellus Shale. Available from: http://www.dec.ny.gov/energy/46288.html (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Minerals. 2007 October. Application to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law. Available from: http://www.dec.ny.gov/docs/materials_minerals_pdf/eaf_dril.pdf (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Minerals. 2007 January. Environmental Assessment Form. Available from: http://www.dec.ny.gov/docs/materials_minerals_pdf/eaf_dril.pdf (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Solid and Hazardous Materials. [undated]. Medical Waste Disposal Form. Available from: http://www.dec.ny.gov/docs/materials_minerals_pdf/medwste.pdf (accessed September 29, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Water. c2009. Multi-Sector General SW Permit and Forms. Available from: http://www.dec.ny.gov/chemical/9009.html (accessed September 29, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Water. c2009. Technical & Operational Guidance Series. Available from: http://www.dec.ny.gov/regulations/2652.html (accessed September 30, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Water. c2009. Water Proposed & Recently Adopted Regulations. Available from: http://www.dec.ny.gov/regulations/39559.html (accessed September 17, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Water. c2009. Watersheds, Lakes, Rivers. Available from: http://www.dec.ny.gov/lands/26561.html (accessed September 3, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Division of Water. 1989 January. Guidelines for Design of Dams. Available from: http://www.dec.ny.gov/docs/water_pdf/damguideli.pdf (accessed September 17, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Office of Air, Energy, & Climate. 2009 July 15. Guide for Assessing Energy Use & Greenhouse Gas Emissions in an Environmental Impact Statement. Available at http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf (accessed September 22, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Office of Climate Change. c2009. Climate Change--New Yorkers are Working on Many Fronts. Available at http://www.dec.ny.gov/energy/44992.html (accessed September 22, 2009).

[NYSDEC] New York State Department of Environmental Conservation, Office of Remediation and Materials Management. 2008 September 23. DER-17: Guidelines for Inspecting and Certifying Secondary Containment Systems of Aboveground Petroleum Storage Tanks at Major Oil Storage Facilities. Available from: http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf (accessed September 4, 2009).

[NYSDEC] New York State Department of Environmental Conservation. 1984 December 19. Public Information Meeting Pursuant to SEQR--Commissioner's Decision.

[NYSDOH] New York State Department of Health. [undated]. New York State Laws and Regulations--NYCRR Title 10. Available from: http://www.health.state.ny.us/nysdoh/phforum/nycrr10.htm (accessed September 4, 2009).

[NYSDOH] New York State Department of Health. 2009 July. Drinking Water Program: Facts and Figures. Available from: http://www.health.state.ny.us/environmental/water/drinking/facts_figures.htm (accessed August 27, 2009).

[NYSDOH] New York State Department of Health. 2008 September. Individual Water Supply Wells--Fact Sheet #1. Available from: http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs1_additional_measures.htm (accessed August 26, 2009).

[NYSDOH] New York State Department of Health. 2008 September. Individual Water Supply Wells--Fact Sheet #3. Available from: http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs3_water_quality.htm (accessed September 16, 2009).

[NYSDOH] New York State Department of Health. 2008 September. Individual Water Supply Wells--Fact Sheet #5. Available from: http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs5_susceptible_water_sources.htm (accessed August 27, 2009).

[NYSDOH] New York State Department of Health. 2007 September. Appendix 5-B: Standards for Water Wells. Available from: http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm (accessed August 27, 2009).

[NYSDOH] New York State Department of Health. 2007 September. Appendix 5-B: Standards for Water Wells; Table 1--Required Minimum Separation Distances to Protect Water Wells From Contamination. Available from: http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1 (accessed August 26, 2009).

[NYSDOH] New York State Department of Health, Wadsworth Center. [undated]. Environmental Laboratory Approval Program. Available from: http://www.wadsworth.org/labcert/elap/elap.html (accessed September 29, 2009).

Ohio Department of Natural Resources, Division of Mineral Resources Management. 2008. Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio. 64 pp.

Pagano S. 1990 October 23. Memorandum to Regional Water Engineers, Bureau Directors, Section Chiefs. Available from: http://www.dec.ny.gov/docs/water_pdf/togs213.pdf (accessed August 27, 2009).

Reiser DW, Ramey MP, Lambert TR. 1988. Review of flushing flow requirements in regulated streams. In Nelson WR, Dwyer JR, Greenberg WE, eds. Flushing and Scouring Flows for Habitat Maintenance in Regulated Streams. Washington, D.C.: U.S. Environmental Protection Agency.

Sanford KF. 2007 April 18. Letter to Kenneth E. Moriarty, NYCDEP.

Sovas GH. 2003 April 19. Supplemental Findings Statement. SEQR File No. P0-009900-00046. Available from: http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindsup.pdf (accessed September 3, 2009).

Sovas GH. 1992 September 1. Findings Statement. Available from: http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindorig.pdf (accessed September 3, 2009).

Susquehanna River Basin Commission. 2009 January 15. Regulation of Projects. 18 CFR Parts 801, 806, 807 and 808. Available from: http://www.srbc.net/policies/docs/srbc_regulation_of_projects.PDF (accessed September 29, 2009).

Susquehanna River Basin Commission. 2002 November 8. Policy No. 2003-01. Guidelines for Using and Determining Passby Flows and Conservation Releases for Surface-Water and Ground-Water Withdrawal Approvals. Available from: http://www.srbc.net/policies/docs/Policy%202003_01.pdf (accessed September 29, 2009).

Susquehanna River Basin Commission. [undated]. Marcellus/Utica Shale and Natural Gas Well Development. Available from: http://www.srbc.net/programs/projreviewmarcellustier3.htm (accessed August 27, 2009).

Tennant DL. 1972. A method for determining instream flow requirements for fish, wildlife and aquatic environment. In Pacific Northwest River Basin Commission pp. 3-11.

Tennant DL. 1975. Instream flow regimes for fish, wildlife recreation, and related environmental resources. United States Fish & Wildlife Service. Billings, Montana.

Tennant DL. 1976a. Instream flow regimes for fish, wildlife, recreation and related environmental resources. In Osborn JF and Allman CH, eds. Proceedings of Symposium and Specialty Conference on Instream Flow Needs, Vol. II, American Fisheries Society, Bethesda, Maryland: 359-373.

Tennant DL. 1976b. instream flow regimes for fish, wildlife recreation and related environmental resources. Fisheries. July-August 1(4):6-10.

Tessmann SA. 1980. Environmental assessment, technical appendix E in environmental use sector reconnaissance elements of the western Dakotas region South Dakota study. Brookings, SD: South Dakota State University, Water Resources Research Institute.

United States Department of the Interior and United States Department of Agriculture. 2007. Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development. BLM/WO/ST-06/021+3071/Rev 07. Bureau of Land Management. Denver, Colorado. 84 pp.

[URS] URS Corporation. 2009 August 5. Water-Related Issues Associated with Gas Production in the Marcellus Shale. Prepared for NYSERDA, Albany, NY.

Weinstein BL and Clower TL. 2009 July 28. Draft Potential Economic and Fiscal Impacts from Natural Gas Production in Broome County, New York. Prepared for Broome County Legislators. Available from: http://www.energyindepth.org/wp-content/uploads/2009/03/broome-county-potential-economic.pdf (accessed September 30, 2009).

American Petroleum Institute, 1992, Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil & Gas Production: American Petroleum Institute, Washington, D.C., API Bulletin E2, 45 p.

Argonne National Laboratory, 2009. http://web.ead.anl.gov/dwm/regs/index.cfm

Arthur, J. Daniel, Brian Bohm, and Mark Layne, 2008 "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale", Presented at the Ground Water Protection Council 2008 Annual Forum.

Bou-Rabee, F. and Nur, Amos, 2002. The 1993 M4.7 Kuwait Earthquake: Induced by the Burning of Oil Fields. Kuwait Journal of Science and Engineering, 29(2).

Brownell, M., 2008, Balancing Economic Development & Environmental Impacts in the Susquehanna River Basin, Pennsylvania Natural Gas Summit, December 11, 2008. http://www.srbc.net/programs/docs/PANatura%20GasSummit-StateCollege12-11-08.PDF

Charpentier, R. R.; W. deWitt, Jr.; G.E. Claypool, L.D. Harris, R.F. Mast, J. D. Megeath, J. B. Roen, and J.W. Schmoker, 1982, "Estimates of Unconventional Natural-Gas Resources of the Devonian Shale of the Appalachian Basin", USGS Open-File Report 82-474.

Delaware County Planning, 2009, Personal communications between Delaware County (Nicole Franzese) and Alpha Geoscience, June 9, 2009.

DRBC, 1961, Delaware River Basin Compact, DRBC, West Trenton, NJ, 55 p.

DRBC, 2002, Administrative Manual, Rules of Practice and Procedure, 45pp.

DRBC, 2009, Personal communications between DRBC (Laura Tessieri) and Alpha Geoscience, May 11, 2009.

DRBC, September 2008, Delaware River Basin Water Code, with Amendments Through July 16, 2008, 18 CFR Part 410, DRBC, West Trenton, NJ, 182 p.

Duffield, W.A. and J.H. Sass, 2003, Geothermal Energy – Clean Power from the Earth's Heat, USGS Circular No. 1249, 36 pp. http://pubs.usgs.gov/circ/2004/c1249

Dyer, B.C., U. Schanz, T. Spillmann, F. Ladner and M.O. Häring, 2008, Microseismic Imaging of a Geothermal Reservoir Stimulation, The Leading Edge; July 2008; v. 27; no. 7; p. 856-869; DOI: 10.1190/1.2954024© 2008 Society of Exploration Geophysicists.

Engelder, Terry and Gary G. Lash, 2008, "Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia," in The American Oil and Gas Reporter, May 2008.

Federal Remediation Technologies Roundtable, August 12, 2009. Remediation Technologies Screening Matrix and Reference Guide, Version 4.0. http://www.frtr.gov/matrix2/section4/4-54.html

FEMA, 2009a, "Federal Emergency Management Agency Community Status Book Report, June 4, 2009", http://www.fema.gov/fema/csb.shtm

FEMA, 2009b, Personal communications between FEMA Map Service Center (Travis McGilton) and Alpha Geoscience, May 8, 2009.

Fletcher, Jon B., Lynn R. Sykes, Lamont-Doherty Geological Observatory of Columbia University, Palisades, New York 10964, September 10, 1977, "Earthquakes Related to Hydraulic Mining and Natural Seismic Activity in Western New York State", Journal of Geophysical Research, Vol. 82, No. 26

Florentin, L., S. Ulrich, and H. Markus, 2007, Part 1: Geological and hydraulic evaluation of the geothermal reservoir Basel 1, 5th Swiss Geoscience Meeting, Geneva 2007. http://www.geothermal.ch/fileadmin/docs/downloads/geoladnertalk.pdf

Foxall, W., and Friedmann, S. J., 2008, Frequently Asked Questions About Carbon Sequestration and Earthquakes, LLNL-BR-408445. https://eed.llnl.gov/co2/pdf/Seismicity_FAQs_final4.pdf

Freeze, R. Allan and John A. Cherry, 1979, Groundwater, Prentice –Hall, Inc, Englewood Cliffs, NJ, 604 Frohlich, C., 2009, personal communication

Gaudlip, A.W., Paugh, L.O., and T.D. Hayes, 2008, "Marcellus Shale Water Management Challenges in Pennsylvania", presented at the SPE Shale Gas Production Conference, Dallas, TX, November 18, 2008.

Geoscience Australia, 2009, http://www.ga.gov.au/minerals/research/national/geothermal/

Geosciences Australia, 2008. Induced Seismicity and Geothermal Power Development in Australia. GEOCAT #66220.

Gowan, S.W., and S. M. Trader, 2000, Mine Failure Associated with a Pressurized Brine Horizon: Retsof Salt Mine, Western New York, Environmental & Engineering Geoscience, Vol. VI, No.1, February 2000 (Winter), pp. 57-70. http://eeg.geoscienceworld.org/cgi/content/abstract/6/1/57

Gowan, S.W., S.M. Trader, M.E. Piel, and L.D. Milliken, 2006, "Stratigraphy of the Devonian and Upper Silurian in the Vicinity of the Retsof, Sterling, and Hampton Corners Mines in Livingston County, New York, NYS Museum Map and Chart Series No. 45, 72 p.

Grey, James E., June 4, 2009, Letter to Ms. Kathleen Sanford, NYSDEC, re: NY DEC SGEIS Information Requests, 18 p.

Halliburton, August 12, 2009. The Barnett Shale. http://www.halliburton.com/public/solutions/contents/Shale/related_docs/Barnett.pdf

Health Physics Society, 2009. http://hps.org

Hill, David G., Tracy E. Lombardi, and John P. Martin, 2002. "Fractured Shale Gas Potential in New York".

Isachsen, Y.W., and W. McKendree, 1977. Preliminary Brittle Structure Map of New York State. New York State Museum Map and Chart Series No. 31. Digitized for GIS http://www.nysm.nysed.gov/gis

Isachsen, Y.W., E. Landing, J.M. Lauber, L.V. Rickard, and W.B. Rogers, editors, 1991. Geology of New York – A Simplified Account. New York State Museum Educational Leaflet No. 28.

Junex, Inc., 2009, Press Release, "Junex's Partner Announces Preliminary Results from Utica Shale Operations", February 24, 2009.

Kessey, Rick, May 12, 2009, Fortuna, personal communication.

LA Office of Conservation, 2009, http://dnr.louisiana.gov/cons/CONSERIN?UIC.ssi

Lash, Gary G., 2009, "Overview of the Tectonic and Eustatic Framework of Devonian Black Shale, Appalachian Basin", Presented at the Society of Petroleum Engineers Water Management Technology Work Shop, March 31, 2009.

LCSN, 2009. "Lamont-Doherty Cooperative Seismographic Network" http://www.ldeo.columbia.edu/LCSN/

Leone, James, 2009, Personal Communications with Alpha Geoscience and GIS data coverage generated from NYS Museum Reservoir Characterization Group Data.

Marcellus Shale Committee, July 22, 2009, "Natural Gas, Tapping Pennsylvania's Potential." http://www.pamarcellus.com/protection.php.

Martin, John, 2005, "Utica Shale Deposition in the Taconic Foreland Basin: Evolution and the Potential for Natural Gas Production," Presented at GSA Northeastern Section 40th Annual Meeting, March 14-16, 2005.

McBurney, E.E., 2008, "Radiation Protection from NORM and TENORM in the Oil and Gas Industry: Regulatory and Non-Regulatory Approaches", PowerPoint Presentation to IRPA-12, October 2008.

MCEER, 2009, http://mceer.buffalo.edu/infoservice/reference_services/westernNewYorkEQs.asp

Milici, Robert C., 2005, “Assessment of Undiscovered Natural Gas Resources in Devonian Black Shales, Appalachian Basin, Eastern USA”, USGS Open-File Report 2005-1268.

Mitsuru, et. al., 2006. Numerical Simulation of Crack Propagation with Shear Slip. Induced by Hydraulic Fracturing. http://sciencelinks.jp/j-east/article/200618/000020061806A0351175.php

Nyahay, Richard, James Leone, Langhorne Smith, John Martin, and Daniel Jarvie, 2007, “Update on the Regional Assessment of Gas Potential in the Devonian Marcellus and Ordovician Utica Shales in New York”.

NYCDEP web page: History of Drought and Water Consumption. http://www.nyc.gov/html/dep/html/drinking_water/droughthist.shtml

NYCDEP, 2006, Watershed Protection Program Summary and Assessment, Prepared by the Bureau of Water Supply.

NYCDEP, 2009, New York City 2008 Drinking Water Supply and Quality Report.

NYSDEC, 1993, Nonindigenous Aquatic Species Comprehensive Management Plan, Division of Fish and Wildlife, 39pp.

NYSDEC, 1999, An Investigation of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Wells in New York State, NYSDEC, Division of Solid and Hazardous Materials, Bureau of Radiation and Hazardous Site Management, Albany, NY, 86 p.

NYSDEC, 2005, Final Report of the New York State Invasive Species Task Force, Fall 2005, 146pp.

NYSDEC, 2007, “2007 Annual Oil and Gas Production Data”. http://www.dec.ny.gov/pubs/36033.html

NYSDEC, 2008, “2008 Annual Oil and Gas Production Data”. http://www.dec.ny.gov/energy/36159.html

NYSDEC, 2009, Comprehensive Wildlife Conservation Strategy (CWCS) Plan, http://www.dec.ny.gov/animals/30483.html

NYSDEC, 2009, Personal communication between NYSDEC Central Office PBS personnel and Alpha Geoscience, June 8, 2009.

NYSDEC, August 12, 2009. Marcellus Shale. http://www.dec.ny.gov/energy/46288.html

NYSDEC, August 31, 2005, “Recommended Pump Test Procedure for Water Supply Application”. Appendix 10, TOGS 3.2.1.

NYSDEC, July 9, 2009. Data on Oil, Gas, and Other Wells in New York. http://www.dec.ny.gov/energy/1603.html

NYSDOH, 2009a. Personal communications with Dave Rowley, Division of Water Supply, Rochester District Office June 9, 2009.

NYSDOH, 2009a. Personal communications with Jane Thapa, Division of Water Supply June 2, 2009.

NYSDOH, April 2001. New York State Aquifers retrieved from http://www.nysgis.state.ny.us/gis9/nyaquifers.zip

NYSDOH, July 2008. Drinking Water Protection Program retrieved on June 9, 2009 from http://www.health.state.ny.us/environmental/water/drinking/index.htm

NYSDOH, July 2009. “Drinking Water Program: Facts and Figures.” retrieved from http://www.health.state.ny.us/environmental/water/drinking/facts_figures.htm

NYSDOT, 2009, http://www.nysdot.gov/divisions/operating/osss/truck/regulations

NYSERDA, 2002

NYSERDA, undated

PHMSA, 2009, http://phmsa.dot.gov/portal/site/PHMSA

Pinnacle Technologies, Inc., August 11, 2009. Microseismic.

Pinnacle Technologies, Inc., August 11, 2009. FracSeis Microseismic Fracture Mapping.http://www.pinntech.com/pubs/TU/TU02_MS.pdf http://www.pinntech.com/microseismic.html

Pratt, Dave, April 19, 2001. “Deep Well Injection and Triggered Earthquakes.” Internal DEC-DMR working document.

Rickard, Lawrence V., 1989. “Stratigraphy of the Subsurface Lower and Middle Devonian of New York, Pennsylvania, Ohio, and Ontario”. New York State Museum Map and Chart Series Number 39.

Sansalone, J., E. Voon, and V. Srinivasan, 2001. Management of Invasive Species Transported in Ballast Water by Dissolved Air Flotation Technology, Louisiana State University.

Proceedings of the Second International Conference on Marine Bioinvasions, New Orleans, La., April 9-11, 2001, pp. 119-120.

Sauder, Elizabeth, 2009, Water Disposal Wells Possibly Linked to Earthquakes, Not Fractured Wells, Texas Energy and Environment Blog, August 14, 2009, http://energyandenvironmentblog.dallasnews.com/archives/2009/08/water-disposal-wells-possibly.html

Schopp, Robert D., and Gary D. Firda, 2008, "Flood Management and Frequency of the Delaware River in New Jersey, New York, and Pennsylvania", USGS Open-File Report 2008-1203.

Selley, Richard C. 1998. "Elements of Petroleum Geology", 2nd Edition, Academic Press.

Sierra Club Atlantic Chapter, undated, "Protect NY's Resources from the New Gas Rush". Retrieved from http://newyork.sieraclub.org/lhg/fliers/Gas%20Hadout.pdf

Smith, K. P., Blunt, G. P., and Tebes, Cl.L., 1996, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactiv Materials Generated by the Petroleum Industry, Argonne National Laboratory/Environmental Assessment Division-2, Argonne, IL, 69 p.

Smith, Langhorne and James Leone, 2009, "Integrated Characterization of the Devonian Marcellus Shale Play in New York State", Presented at the Marcellus Shale Gas Symposium, Hudson Mohawk Professional Geologists Association, Albany, NY, April 29, 2009.

Smith, Langhorne, 2009. Personal Communications with Alpha Geoscience and GIS data coverage generated from NYS Museum Reservoir Characterization Group Data.

SMU, 2009, SMU Seismologist: More Study Needed in North Texas Quakes, http://www.smu.edu/News/2009/stump-quakes-13aug2009.aspx

Souders, S., 2005. http://www.strongerinc.org.

SRBC, 1998, Policy Regarding Diversions of Water from the Susquehanna River Basin, Policy No. 98-01.

SRBC, 2007. "June 2009 Flood – A Summary of the Flood and Performance of the Susquehanna Flood Forecast and Warning System", January, 2007.

SRBC, 2009, Personal communications between SRBC (Ben Pratt) and Alpha Geoscience, May 8, 2009.

SRBC, 2009, Standard Docket Conditions Contained in Gas Well Consumptive Water Use Dockets; http://www.srbc.net/programs/projreviewmarcellus.htm

SRBC, February 2007, Susquehanna River Basin Commission Regulation of Projects, 18 CFR Parts 801,806, 807, and 808, SRBC, Harrisburg, PA, 36 p.

SRBC, February 2009, Accommodating a New Straw in the Water is Extracting Natural Gas from the Marcellus Shale in the Susquehanna River Basin. http://www.srbc.net/programs/docs/Marcellus%20Legal%20Overview%20Paper%20(Beauduy).pdf.PDF

SRBC, November 2002, Guidelines for Using and Determining Passby Flows and Conservation Releases for Surface-Water and Ground-Water Withdrawal Approvals, Policy No. 2003-01.

Tetra Tech EM, Inc., 2005, "Delaware County Multi-Jurisdictional Hazard Mitigation Plan (Draft)", Prepared for Delaware County, FEMA, US Department of Homeland Security, and New York State Emergency Management Office, October 31, 2005

USEPA, 2009A. http://www.epa.gov/radiation/tenorm/about.html

USEPA, 2009B. http://www.epa.gov/radiation/tenorm/oilandgas.html

USGS, 1999, Naturally Occurring Radioactive Material (NORM) in Produced Water and Oil-Field Equipment – An Issue for the Energy Industry, U.S.G.S. Fact Sheet FS-142-99, 4 p.

USGS, 2002, "National Assessment of Oil and Gas Project – Appalachian Basin Province Boundary", GIS data coverage.

USGS, 2008a. "New York Seismic Hazard Map." National Seismic Hazard Mapping Project (2008). http://earthquake.usgs.gov/regional/states/new_york/hazards.php

USGS, 2008b. 2008 United States National Seismic Hazard Maps. Fact Sheet 2008-3018.

USGS, 2009, http://ga.water.usgs.gov/edu/wupt.html

USGS, 2009. "Historic Earthquakes – New York." http://earthquake.usgs.gov/regional/states/events/1944_09_05.php

USGS, 2009A, http://pubs.usgs.gov/fs/2004/3022/fs-2004-3022.html

Van Tyne, Arthur M., 1993, "Detailed Study of Devonian Black Shales Encountered in Nine Wells", USGS Bulletin 1909.

VerStraeten, C. A., 2007, "Basinwide Stratigraphic Synthesis and Sequence Stratigraphy, Upper Pragian, Emsians and Eifelian Stages (Lower to Middle Devonian), Appalachian Basin", From Devoinian Events and Correlations. R.T. Becker and W. T. Kirchgasser (eds), Geological Society of London.

Weany, David J. Robert T. Ryder, and Richard Nyahay, 2000, “Thermal Maturity Patterns (CAI and %Ro) in Ordovician and Devonian Rocks of the Appalachian Basin in New York State”, USGS Open-File Report 00-496.

Zaengle, Don, 2009, “Natural Gas Exploration”, Presented at the 12th Annual NYWEA and AWMA Joint Seminar, February 12, 2009.

Zerrahn, Gregory J., 1978, “Ordovician (Trenton to Richmond) Depositioned Patterns of New York State, and their Relation to the Taconic Orogeny”, In Geological Society of America Bulletin v. 89 p., 1751-1760.

ICF International

Health, Safety and Environment Section. 2000 January/February. Alabama lawsuit poses threat to hydraulic fracturing across US. Drilling Contractor; p. 42-43.

Percival PS. 2008 July. The Future of Water Recycling. Fort Worth Basin Oil & Gas Magazine. Available from: http://www.fwbog.com/index.php?page=article&article=18 (accessed August 25, 2009).

Bullin KA and Krouskop PE. 2009. Compositional variety complicates processing plans for US shale gas. Oil and Gas Journal. 107(10).

Natural Gas Lease Forum for Landowners. 2008 August 27-September 4. Current Advanced Practices in Hydrofracture (Hydrofrac) - Hydraulic Fracturing of 'Tight Gas Shale' Formations: The “Listening” Well for Seismic data collection. Available from: http://www.pagaslease.com/pdf_downloads/listening_wells.pdf (accessed August 25, 2009).
2006 April 20. Innovative water conservation technology. Oil & Gas Network Magazine.

Geology.com. c2005-2009. Marcellus Shale - Appalachian Basin Natural Gas Play. Available from: http://geology.com/articles/marcellus-shale.shtml (accessed August 25, 2009).

Alfenore J. 2009. Hydraulic Fracturing Challenges. Paper presented at Hydraulic Fracturing Technical Conference, January 19-21, in The Woodlands, Texas.

Ali S, et al. 2002 Summer. Combined Stimulation and Sand Control. Oilfield Review, p. 30-47.

Arthur JD, Bohm B, Coughlin BJ, Layne M. c2008. Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs. Available from: http://www.all-llc.com/page.php?92 (accessed August 25, 2009).

Al-Reshedan FS, Gawish A, Dmour HN. 2009 February 13. Evaluation the Methodologies of Analyzing Production and Pressure Data of Hydraulic Fractured Wells in Low Permeability Gas Reservoirs. Oil and Gas Business. Ufa, Russia.

American Petroleum Institute. 2004 February. Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. p. 6-9.

Veil JA, Environmental Science Division. 2007 September 30. Trip Report for Field Visit to Fayetteville Shale Gas Wells (ANL/EVS/R-07/4). Available from: www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf (accessed August 25, 2009).

Arkansas Code, Title 15 Natural Resources and Economic Development, Subtitle 6 Oil, Gas, and Brine (1939). Available from: http://www.arkleg.state.ar.us/SearchCenter/Pages/ArkansasCodeSearchResultPage.aspx (accessed 24 July 2009).

Arkansas Department of Environmental Quality. Regulations of the Arkansas Pollution Control and Ecology Commission. Available from: http://www.adeq.state.ar.us/regs/default.htm (accessed April 20, 2009).

Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended, Ark. Code Ann. §8-4-101, et seq.) Authorization to Construct, Operate and Close the Pits Associated with Oil and Gas Well Exploration (00000-WG-P). Available from: http://www.adeq.state.ar.us/water/branch_permits/pdfs/00000-WG-P.pdf (accessed August 25, 2009).

Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended, Ark. Code Ann. §8-4-101, et seq.) Authorization to Land Apply Drilling Fluids (00000-WG-LA). Available from: http://www.adeq.state.ar.us/water/branch_permits/pdfs/00000-WG-LA.pdf (accessed August 25, 2009).

Arkansas Oil and Gas Commission. 2009 February 19. General Rules and Regulations.

Arthur JD, et al. 2008. Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale. Paper presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, in Cincinnati, Ohio.

Bachman R. 2007. Resolving Inconsistencies between Well Test and Designed Fracture Lengths. Paper presented at The Petroleum Society of the CIM Technical Luncheon, November 6.

Barree RD. 2009. Hydraulic Fracture Stimulation in Tight-Gas Reservoirs. Paper presented at the Society of Petroleum Engineers Hydraulic Fracturing Technology Conference, January 19, in The Woodlands, Texas.

Bennett L, et al. 2005. The Source for Hydraulic Fracture Characterization. Oilfield Review; 17(4):47-52.

Bennion DB, Thomas FB, Bietz RF. 1996. Low Permeability Gas Reservoirs: Problems, Opportunities and Solutions for Drilling, Completion, Stimulation and Production (Paper

No. SPE 35577). Presented at the Gas Technology Conference, April 28-May 1, in Calgary, Alberta, Canada.

Bennion DB, Thomas FB, Bennion DW, Bietz RF, 1996. Fluid Design to Minimize Invasive Damage In Horizontal Wells. Journal of Canadian Petroleum Technology; 35(9):45-51.

Billman DA. 2008. Geological and Activity Overview of Appalachian Plays. Paper presented at Summer NAPE 2008, in Houston, Texas.

Billman DA. 2009. Geological Overview of Appalachian Shale Plays (or ….. Why Here?, Why Now?). Lecture presented for Geology 699: Colloquium Series on January 22 at Brooks Hall, West Virginia University.

Bolin DE. 2009 May 27. Letter to Michael Paque.

Boone D. 2006. Evaluation of the Barnett Shale, The process and results using PowerTools and Production Data. Paper presented at IHS Energy User Forum, May 18, in Houston, Texas.

Boyer C, Kieschnick J, Suarez-Rivera R, Lewis RE, Waters G. 2006. Producing gas from Its Source. Oilfield Review; 18(3) p. ?.

Bracken L. 2009. Technical Weaknesses in Hydraulic Fracture Modeling and Execution. Available from: http://www.journeyoftheforsaken.com/fracmodeling.htm (accessed 24 July 2009).

Brannon HD. 2009. Fracturing Materials. Paper presented at the Society of Petroleum Engineers Hydraulic Fracturing Technology Conference, January 19-21, in The Woodlands, Texas.

Wyoming Bureau of Land Management. Southwestern Production Corp. Hornbuckle Field Eight Well Environmental Assessment (Chapter 2). Available from: www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/cfodocs/hornbuckle.Par.11552.File.dat/ch2.pdf (accessed August 25, 2009).

Bybee K. 2009. Applying Science and Best Practices To Increase Production and Optimize Economics in a West Texas Gas Field. Journal of Petroleum Technology 61(3):51-53.

Carrillo VG. Letter to Michael Paque, Executive Director, Ground Water Protection Council, May 29, 2009.

Carter, B.J., J. Desroches, A.R. Ingraffea, and P.A. Wawrzynek, 2000. "Simulating Fully 3D Hydraulic Fracturing." in Modeling in Geomechanics, Ed. Zaman, Booker, and Gioda, Wiley Publishers.

Chang, W., 2007. "Modeling production in hydraulically fractured wells with a reservoir simulator," April 27, 2007.

Chesapeake Appalachia LLC, 2009, “Application for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law”, various wells, March 2009.

Chiou, Cary T., Partition and adsorption of organic contaminants in environmental systems, John Wiley & Sons, New York, 2002.

Core Labs, 2003. “Optimization of Hydraulic Fracture Design Using Geomechanics Tests,” 2003.

Crisman Institute for Petroleum Research, 2008. Crisman Institute Newsletter, Issue 3, August 2008.

Curtis, John B., David G. Hill, and Paul G. Lillis, 2008. “Realities of Shale Gas Resources:

Daneshy, A.A., 2009. "Factors Controlling The Vertical Growth of Hydraulic Fractures," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

Darbonne, Nissa, 2006. “The Barnett Shale and Other Shale Dreams,” IHS Energy User Forum, 17 May 2006.

Delaware River Basin Commission, 2008. “Natural Gas Drilling in the Marcellus Shale Formation,” URL: http://www.state.nj.us/drbc/naturalgas.htm, November 18, 2009.

Dmour, Hazim N. and Eissa M. Shokir, 2008. “Pre-Post Frac Test Data Analysis for Hydraulically Fractured Vertical Tight Gas Well-Field Case Study,” 2008.

DOE, Energy Information Administration, 2009. “Maps: Exploration, Resources, Reserves, and Production,” URL: http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm, 2009

DOE, Office of Fossil Energy, 2007. “Development of an Advanced Hydraulic Fracture Mapping System,” Prepared under DE-FC26-04NT42108.

DOE, Office of Fossil Energy, 2009. Modern Shale Gas Development in the United States: A Primer, Prepared under DE-FG26-04NT15455.

DOE, Office of Fossil Energy, 2009. State Oil and National Gas Regulations Designed to Protect Water Resources, May 2009.

DOE, Office of Fossil Energy, 2009. State Oil and National Gas Regulations Designed to Protect Water Resources, Reference Document, May 2009.

DOE, Office of Legacy Management, 2008. “Rulison and Rio Blanco Sites,” Presented at the Northwest Colorado Oil and Gas Forum, September 4, 2008, Rifle, Colorado.

Dozier, George, et al, Undated. “Refracturing Works,” Oilfield Review, Autumn 2003, p. 38-53.

Drilling Waste Management Information System, “Fact Sheet - Using Muds and Additives with Lower Environmental Impacts,” URL: http://web.ead.anl.gov/dwm/techdesc/lower/index.cfm, accessed 9 July 2009.

Driving the Future of Unconventional Gas,” AAPG Annual Meeting, San Antonio, April 22, 2008.

Energy Information Administration. tonto.eia.doe.gov/FTPROOT/modeldoc/m063(2001).pdf, pg 11

Energy Resources Conservation Board, 2008. “Clarification to Directive 027: Shallow Fracturing Operations—Interim Controls, Restricted Operations, and Technical Review,” Bulletin 2008-19, April 25, 2008.

Energy Resources Conservation Board, 2008. “Shallow Fracturing Operations—Interim Controls, Restricted Operations, and Technical Review,” Directive 027, April 25, 2008.

Energy Resources Conservation Board, 2009. “Shallow Fracturing Operations—Restricted Operations,” Directive 027-Draft, February 25, 2009.

Engelder, Terry and Gary G. Lash, 2008, “Marcellus Shale Play’s Vast Resource Potential Creating Stir in Appalachia”, The American Oil & Gas Reporter, May 2008.

Engelder, Terry and Gary G. Lash, 2008, “Science behind the Marcellus Play, The Devonian Black Shale Play of the Appalachian Basin”.

Engelder, Terry, 2008, “Structural geology of the Marcellus and other Devonian gas shales: Geological conundrums involving joints, layer-parallel shortening strain, and the contemporary tectonic stress field,” Department of Geosciences, The Pennsylvania State University.

Environmental Defense Fund. Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements. 26 Jan 2009. www.edf.org/documents/9235_Barnett_Shale_Report.pdf

EPA AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. epa.gov/ttn/chief/ap42/index.html

EPA AP-42, Fifth Edition. Table 1.4-2 www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

EPA AP-42, Fifth Edition. Table 13.5-1. www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf

Fesmire, Mark E.,Director, New Mexico Oil Conservation Division, Letter to Mr. Michael Paque, Executive Director, Ground Water Protection Council, May 29, 2009.

Final Statewide Oil and Gas EIS and Proposed Amendment of the Powder River and Billings RMP's (Montana CBM EIS) - www.deq.state.mt.us/CoalBedMethane/FinalEIS/Volume%20I/07%20Chapter-4.pdf

Fischer, T., S. Hainzl, Z. Jechumtalova, and L. Eisner, Undated. "Microseismic Signatures of Hydraulic Fracture Propagation in Sediment Formations," Proceedings from the Thirty-Third Workshop on Geothermal Reservoir Engineering, January 28-30, 2008, Stanford University, Stanford, California.

Flesher, Robert, 2009. "Stimulation in Tight Gas Sands," Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

Fokker, Peter, 2007. "Hydraulic Fracturing," TNO Built Environment and Geosciences, Geological Survey of the Netherlands, The Netherlands.

GAO, 1989. Drinking Water - Safeguards Are Not Preventing Contamination From Injected Oil and Gas Wastes, Report to the Chairman, Environment, Energy, and Natural Resources Subcommittee, Committee on Government Operations, House of Representatives, July 1989.

Gas Research Institute, Methane Emissions from the Natural Gas Industry, Volume 8. epa.gov/gasstar/tools/related.html

Gas Technology Institute. gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage\12352.xml

Geospace Technologies, 2004. "Microseismic hydraulic fracture monitoring," 2004.

Givens, Natalie and Hank Zhao, 2009. "The Barnett Shale: Not So Simple After All," Republic Energy, URL: http://republicenergy.com/Articles/Barnett_Shale/Barnett.aspx, 2009.

Gottschling, J .C., T. N. Royce, and L. Z. Shuck, 1985. "Nitrogen Gas and Sand: A New Technique for Stimulation of Devonian Shale," Journal of Petroleum Technology, May 1985, p. 901-907.

Ground Water Protection Council, 1998, Survey Results on Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States, December 15, 1998.

Ground Water Protection Council, 2009. "Statement of Scott Kell before the House Committee On Natural Resources Subcommittee on Energy and Mineral Resources", Washington, D.C., June 4, 2009.

Halliburton, 2007. “Advances in Unconventional Gas,” Hart Energy Publishing, Houston, Texas.

Halliburton, 2008. “Trends in Unconventional Gas,” Articles from Oil and Gas Journal, 2007-2008.

Harper, John A., “The Marcellus Shale—An Old “New” Gas Reservoir in Pennsylvania,” Pennsylvania Geography, Spring 2008, Vol. 38, No. 1.

Hawkes, R., 2007. "Pre-frac Reservoir Characterization from Perforation Inflow Diagnostic (PID) Testing - Measure Twice –Frac Once," Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Series.

Haywood, Phaedra, 2008. “Panel gives green light to drilling ordinance,” The New Mexican, Santa Fe, 9 December 2008.

Heinze, Jim, “Stimulation in Gas Shales,” Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

Hexion, S.V."Fracturing Technology: Improving technology for fracture height,” E&P Magazine, September 2008.

Hill, David G., Tracy E. Lombardi and John P. Martin, 2003, “Fractured Shale Gas Potential in New York”, New York State Energy Research and Development Authority, Albany, New York, USA.

Holditch, Stephen A., 2009. “Summary of Ideas on How Hydraulic Fracture Treatment Technology Transfer Will Expand Development of Unconventional Gas Worldwide,” Presented at Hydraulic Fracturing Technology Conference 2009, January 19-21, 2009, The Woodlands, Texas.

Independent Petroleum Association of America, 2007. The Oil & Gas Producing Industry in Your State,” Washington, D.C., August 2007.

IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: http://srdata.nist.gov/solubility/index.aspx.

Jacoby, C. H. and L. F. Dellwig, “Appalachian Foreland Thrusting in Salina Salt, Watkins Glen, New York,” Presented at the Fourth International Symposium on Salt-Northern Ohio Geological Survey.

Jared Hall, East Resources Inc. General Mgr. Teleconference @ 2p.m. 4/13/09

Joseph, D. D., 2000. “Direct Simulation of the Motion of Particles in Flowing Liquids: Industrial Problems: Hydraulic Fracturing,” Industrial Problems, URL: http://www.aem.umn.edu/Solid-Liquid_Flows/industry.html, 2000.

Kaufman, P., G.S. Penny, and J. Paktinat, 2008. "Critical Evaluations of Additives Used in Shale Slickwater Fracs," SPE 119900, Presented at 2008 SPE Shale Gas Production Conference, November 16-18, 2008, Irving, Texas.

Kell, Scott, Letter to Mr. Michael Paque, Executive Director, Ground Water Protection Council, May 27, 2009.

Kell, Scott, Testimony on behalf of the Ground Water Protection Council to the House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources, Washington, DC, June 4, 2009.

Kopel, Dave, "ProPublica's shaky facts," Rocky Mountain News. January 10, 2009.

Lambe, T. William, Soil Testing for Engineers, John Wiley & Sons, Inc., New York, 1951.

Lash, Gary G., 2008. "Stratigraphy and Fracture History of the Middle and Upper Devonian Succession, Western New York – Significance to Basin Evolution and Hydrocarbon Exploration", Dept. of Geosciences, SUNY Fredonia, New York.

Lee, Joseph, J., Letter to Mr. Michael Paque, Executive Director, Ground Water Protection Council, June 1, 2009.

Louisiana Administrative Code, 2007. Title 43, Part 15, "Office of Conservation—Surface Mining," October 2007.

Louisiana Administrative Code, 2007. Title 43, Part 17, "Office of Conservation—Injection and Mining," October 2007.

Louisiana Administrative Code, 2007. Title 43, Part 9, "Office of Conservation—Natural Gas Policy Act," December 2007.

Louisiana Administrative Code, 2008. Title 43, Part 19, "Office of Conservation—General Operations," Subpart 1. Statewide Order No. 29-B, December 2008.

Louisiana Office of Conservation, 2006. "Engineering Division Permit and Reservoir Section," URL: http://dnr.louisiana.gov/cons/CONSEREN/Permits/permitssection.ssi, September 28 2006

Majer, Ernest L., John E. Peterson, Thomas Daley, Kurt NiHei, Larry Myer, Don Vasco, Chris Doughty, John Queen, Peter D'Onfro, William Rizer, and Akhil Datta-Gupta, 1998. "Results of High Resolution Seismic Imaging Experiments for Defining Permeable Pathways in Fractured Gas Reservoirs," DOE Contract No. DE-AC03-76SF00098.

Malpani, R.V., December 2006. Selection of Fracturing Fluid for Stimulating Tight Gas Reservoirs, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

Martin, T., 2007. “Appropriate Hydraulic Fracturing Technologies for Mature Oil and Gas Formations,” Presented as part of the Society of Petroleum Engineers Distinguished Lecturer Program.

Matthews, H. Lee, “Overview of Shale Gas Stimulation Techniques,” Search and Discovery Article #40335, Adapted from oral presentation at AAPG Annual Convention, April 20-23, 2008, San Antonio, Texas.

Maxwell, S.C., T.I. Urbancic, N. Steinsberger, Devon, and R. Zinno, “Fracs tracked using microseismic images,” E&P, August 2003, p. 58-59.

Mayerhofer, M.J., E.P. Lolon, J.F. Youngblood, and J.R. Heinze, 2006. “Integration of Microseimic Fracture Mapping Results With Numerical Fracture Network Production Modeling in the Barnett Shale,” Report No. SPE 102103, Prepared for SPE Annual Technical Conference and Exhibition, September 24-27, 2006, San Antonio, Texas.

Mayerhofer, Michael, Norm Warpinski, and Elyezer Lolon, 2008. “Use of Fracture-Mapping Technologies to Improve Well Completions in Shale Reservoirs,” Search and Discovery Article #40336, Adapted from oral presentation at AAPG Annual Convention, April 20-23, 2008.

M-I SWACO: Land Mud-Gas Separator Features & Benefits. www.miswaco.com/Products_and_Services/Drilling_Solutions/Pressure_Control/Mud_Gas_Separators/Mud_Gas_SeparatorsDocuments/LAND%20MUD-GAS%20SEPARATOR.cfm

Michigan DEQ, Environmental Science and Services Division. Emission Calculation Fact Sheet. Fact Sheet #9845. October, 2006

Milliken, L. D., M. E. Piel, S. M. Trader, and S. W. Gowan, 2006. “Stratigraphy of the Devonian and Upper Silurian in the Vicinity of the Retsof, Sterling, and Hampton Corners Mines in Livingston County, New York,” New York State Museum Map and Chart Series No. 45.

Mills, Kelly W., 2006. Updated Evaluation for the North-Central Texas – Trinity and Woodbine Aquifers – Priority Groundwater Management Study Area, Draft, Priority Groundwater Management Area File Report, September 2006.

Mohaghegh, S., B. Balan, S. Ameri, and D.S. McVey, 1996. “A Hybrid, Neuro-Genetic Approach to Hydraulic Fracture Treatment Design and Optimization,” SPE 36602, Presented at the SPE Annual Technical Conference & Exhibition, October 6-9, 1996, Denver, Colorado, Report No. SPE 36602.

National Resource Defense Council, 2002. “Hydraulic Fracturing of Coalbed Methane Wells: A Threat to Drinking Water,” January 2002.

New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Parts 550 through 559, (as of 5 April 2009).

New York State, 2009, Environmental Conservation Law, Article 23, URL: http://public.leginfo.state.ny.us, accessed 4 August 2009.

NY DEC SGEIS Information Request Responses from Fortuna, Chesapeake and East Resources

NYSDEC, 2009, "Final Scope for Draft Supplemental Generic Environmental Impact Statement (dSGEIS) 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", February 2009.

NYSDEC, 2009. "Designing and Drilling Your Well," URL: http://www.dec.ny.gov/energy/1628.html, 2009.

NYSDEC, 2009. "Financial Security," URL: http://www.dec.ny.gov/energy/1622.html, 2009.

NYSDEC, 2009. "Mineral Resources Environmental Notice Bulletin," URL: http://www.dec.ny.gov/energy/1634.html, 2009.

NYSDEC, 2009. "Oil, Gas and Solution Salt Mining Forms," URL: http://www.dec.ny.gov/energy/4761.html, 2009.

NYSDEC, 2009. "Organizational Report," URL: http://www.dec.ny.gov/energy/1624.html, 2009.

NYSDEC, 2009. "Regulated Well Types," URL: http://www.dec.ny.gov/energy/1632.html, 2009.

NYSDEC, 2009. "Required Reports," URL: http://www.dec.ny.gov/energy/1616.html, 2009.

NYSDEC, 2009. "Shut-In or Temporary Abandonment," URL: http://www.dec.ny.gov/energy/1614.html, 2009.

NYSDEC, 2009. "Technical Guidance Memoranda," URL: http://www.dec.ny.gov/energy/1626.html, 2009.

NYSDEC, 2009. "Underground Gas Storage Permitting Process," URL: http://www.dec.ny.gov/energy/1612.html, 2009.

NYSDEC, 2009. "Well Owner and Applicants Information Center," URL: http://www.dec.ny.gov/energy/1522.html, 2009.

NYSDEC, 2009. “Well Ownership Responsibilities,” URL: http://www.dec.ny.gov/energy/1639.html, 2009.

NYSDEC, 2009. “Well Permitting Process,” URL: http://www.dec.ny.gov/energy/1772.html, 2009.

NYSDEC, 2009. “Well Plugging,” URL: http://www.dec.ny.gov/energy/1618.html, 2009.

NYSDEC, 2009. “Well Transfer,” URL: http://www.dec.ny.gov/energy/1620.html, 2009.

NYSDEC, -Bureau of Oil and Gas Regulation, Undated. “Compulsory Integration Election Form,” Form No. 06-1-1.

NYSDEC, Division of Mineral Resources, “Applicant's Checklist for Spacing Unit Map,” Undated.

NYSDEC, Division of Mineral Resources, 1992. Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, July 1992.

NYSDEC, Division of Mineral Resources, Undated. “Annual Well Report.”

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 1984. Financial Security Worksheet, Form No. 85-11-2 (11/84), November 1984.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2004. “Request for Shut-in or Temporary Abandonment,” Form No. 85-16-4 (11/04)–10d, November 2004.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2006. “Instruction for Plugging Report Form,” Form No. 85-15-8 (06/06)--7f, June 2006.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2006. “Instructions for Notice of Intention to Plug and Abandon Form,” Form No. 85-12-4 (01/06)-27b, January 2006.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2006. “Notice of Intention to Plug and Abandon,” Form No. 85-12-4 (01/06)-27b, January 2006.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2006. “Plugging Report,” Form No. 85-15-8 (06/06)--7f, June 2006.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2006. “Request for Well Transfer,” Form No. 85-12-9 (2/06)–10g, February 2006.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. “Application for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law,” Form No. 85-12-5 (10/07), October 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Application for Transfer of Underground Storage Permit and Application for Transfer of Pending Underground Storage Application," Form No. 07-ST-1 (1/07), January 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Environmental Assessment Form, Form No. 85-16-5 (1/07)-10b, January 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Instruction for Application for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Law Form," Form No. 85-12-5 (10/07), October 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Instructions for Well Drilling and Completion Report Form," Form No. 85-15-7 (10/07)--28a, October 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Organizational Report," Form No. 85-15-12 (6/07)–28b, June 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2007. "Well Drilling and Completion Report," Form No. 85-15-7 (10/07)--28a, October 2007.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2008. "Application for A.P.I Well Identification Number," Form No. 85-16-1 (04/08), April 2008.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, 2008. "Well Plugging and Surface Restoration Bond," Form No. 85-02-2 (04/08)–10a, April 2008.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, Undated. "Application for a Non-conforming Spacing Unit or a Variance from Regulatory Well Spacing," Form No. 07-01-05.

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, Undated. "Application for Transfer of Underground Storage Permit and Application for Transfer of Pending Underground Storage Application – General Instructions."

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, Undated. "Template Letter for Certificate Deposit."

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, Undated. "Template Letter for Irrevocable Letter of Credit."

NYSDEC, Division of Mineral Resources-Bureau of Oil and Gas Regulation, Undated."Affirmation of Acreage Control & Rights in Target Formation."

NYSDEC. 2009, “Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program,” URL: http://www.dec.ny.gov/energy/45912.html, accessed 3 February 2009.

NYSERDA, 2007, New York’s Natural Gas and Oil Resource Endowment: Past, Present and Potential.

OSHA. www.osha.gov/SLTC/etools/oilandgas/illustrated_glossary/mud_return_line.html

PADEP, 2007. “Oil and Gas Well Drilling and Production in Pennsylvania,” Fact Sheet, April 2007.

PADEP, Bureau of Oil and Gas Management, 2001. Oil and Gas Operators Manual, Document No. 550-0300-001, October 30, 2001.

PADEP, Bureau of Oil and Gas Management, Bureau of Watershed Management, 2008. “Application Addendum and Instructions for Marcellus Shale Gas Well Development,” Form No. 5500-PM-OG0083, October 2008.

PADEP, Bureau of Oil and Gas Management, Bureau of Watershed Management, 2008. “Application Addendum for Marcellus Shale Gas Well Development Checklist for Submittal,” Form No. 5500-PM-OG0083, October 2008.

PADEP, Undated. “Bureau of Oil and Gas Management,” URL: http://www.dep.state.pa.us/dep/deputate/minres/OILGAS/oilgas.htm.

PADEP, Undated. “Table 1, Summary of Hydraulic Fracture Solutions – Marcellus Shale.”

Paktinat, J., J. Pinkhouse, J. Fontaine, G. Lash, and G. Penny, 2009. “Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin,” Search and Discovery Article #40391(2009), Adapted from extended abstract presented at AAPG Convention, April 20-23, 2008, San Antonio, Texas, March 16, 2009.

Pennsylvania Code, Chapter 78. Oil and Gas Wells, August 1, 1987.

Pennsylvania Code, Chapter 79. Oil and Gas Conservation, August 13, 1971.

Pennsylvania Code, Chapter 91. General Provisions, September 3, 1971.

Pennsylvania Department of Community & Economic Development, Undated. “More on Marcellus Shale Factsheet.”

Pennsylvania Department of Environmental Protection. Permit Workload Report. www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/Marcellus/Marcellus.htm

Personal Contact, Kathleen Sanford, NYS DEC, 6/15/2009

Petrocasa Energy, Inc. www.petrocasa.com/3D%20Rig%20Animation%20Web%20Version/index.html

Petroleum Technology Alliance Canada, 2006. Filling the Gap: Unconventional Gas Technology Roadmap, June 2006.

Pipeline Rules of Thumb Handbook, 4th edition. Horsepower selection chart, page 262

Popa, Andrei S., Shahab D. Mohaghegh, Razi Gaskari, and Samuel Ameri,, 2003. "Identification of Contaminated Data in Hydraulic Fracturing Databases: Application to the Codell Formation in the DJ Basin," SPE 83446, Presented at the SPE Western Regional/AAPG Pacific Section Joint Meeting, May 19–24, 2003, Long Beach, California.

Powell, Gene, 2008. "2008 Tarrant County Barnett Shale Well Revenue Estimate For Neighborhoods," Powell Barnett Shale Newsletter, 5 May 2008.

PTTC, 2006. PTTC Appalachian Region Newsletter, Fall 2006, Vol. 7, No. 2.

Railroad Commission of Texas, 2008. "Oil & Gas Proposals for Decision and Orders," URL: http://www.rrc.state.tx.us/meetings/ogpfd/index.php, March 25, 2008.

Railroad Commission of Texas, 2008. "Water Use in the Barnett Shale," URL: http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php, July 30, 2008.

Railroad Commission of Texas, Undated. "Oil & Gas Permits," http://www.rrc.state.tx.us/licenses/og/index.php.

Reynolds, Rodney R., "Produced Water and Associated Issues," Oklahoma Geological Survey, Open-File Report 6-2003. 2003.

Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", AAPG Bulletin, March 1972, v. 56, No. 3, p. 528-536.

Schein, Gary, 2009. "Hydraulic Fracturing in Gas Shale Plays - Are They All the Same?" Presented at the Barnett Shale Breakfast Symposium, February 29, 2009.

Schlumberger, 2003, Services, "DataFRAC Service."

Schlumberger, 2006. "Improve Production with Optimum Fracture Design in Real Time." October 2006.

Schlumberger, 2009. "Case Study: StimMORE Service Increases EUR in Barnett Shale Well by 0.25 Bcf, Integrated approach results in daily production increase of nearly threefold."

Settari, A, 2009. "Review of Fracturing Modeling Technology," Presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, January 19-21, 2009.

Sharma, M.M. et al, 2003. "The Impact of Proppant Placement on the Productivity of Tight Gas Wells," GasTIPS, Fall 2003.

Siebrits, E., J.L. Elbel, R.S. Hoover, I.R. Diyashev, L.G. Griffin, S.L. Demetrius, C.A. Wright, B.M. Davidson, and D.G. Hill, 2000, "Refracture Reorientation Enhances Gas Production in Barnett Shale Tight Gas Wells," SPE 63030, Presented at the 2000 SPE Annual Technical Conference and Exhibition, October 1-4, 2000, Dallas, Texas.

Simon, Yves, 2006. "Stress and fracture characterization in a shale reservoir, North Texas, using correlation between seismic attributes and well data," NAPE, August 22, 2006.

Soeder, Daniel J., "Porosity and Permeability of Eastern Devonian Gas Shale," SPE Formation Evaluation, March 1988, p. 116-124.

Stark, Pete and Curtis Smith, "Perspectives: Cost & Performance Factors

Summary of Chesapeake Delaware County applications for 23 horizontal well. Provided by Carrie Friello (NYS DEC)

Susquehanna River Basin Commission, Undated. "Marcellus Shale and Natural Gas Well Development," URL: http://www.srbc.net/programs/projreviewmarcellus.htm.

TAURUS Reservoir Solutions Ltd., 2008, "Shallow Nitrogen Fracturing Dimensions and Groundwater Protection, Evaluation of the ERCB Directive 27, Final report," October 8, 2008.

Texas A&M University, 2000. "Simulation and Behavior of Fractured Wells Volume II," July 2000.

Texas Administrative Code, Title 16, Part 1, Chapter 3, Oil and Gas Division.

Tosic, Slavko, Christine Ehlig-Economides, Michael J. Economides, and Mike C. Vincent, Undated. "New Flux Surveillance Approach for High Rate Wells," SPE 115689.

Tschirhart, Nicholas Ray, August 2005. The Evaluation Of Waterfrac Technology in Low-Permeability Gas Sands in the East Texas Basin, A Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

U.S. Department of Energy (DOE). Office of Fossil Energy. "Modern Shale Gas Development in the United States: A Primer" A Primer www.all-llc.com/pdf/ShaleGasPrimer2009.pdf

U.S. Environmental Protection Agency. Frequent Questions. iaq.custhelp.com/cgi-bin/iaq.cfg/php/enduser/std_adp.php?p_faqid=3218

U.S. EPA, 1998. “Legal Issues Related to Coalbed Methane Storage in Abandoned Coal Mines in Virginia, West Virginia, Pennsylvania, Utah, Colorado and Alabama,” White paper prepared under Work Assignment 3-1 of the EPA Contract 68-W5-0018, June 20, 1998.

U.S. EPA, 2003, “Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells”, Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation, 12 December 2003.

U.S. EPA, 2004. Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, Report number: EPA 816-R-04-003.

U.S. EPA, 2009. “Coalbed Methane Outreach Program (CMOP),” URL: http://www.epa.gov/coalbed/, February 19, 2009.

U.S. EPA, Office of Water, 2008. “Contaminant Candidate List 3 Chemicals: Classification of the PCCL to CCL,” Draft Report No. EPA 815-R-08-004, February 2008.

U.S. EPA, Undated. “Fracturing Technologies For Improving CMM/CBM Prodction,” Prepared under Contract 68-W-00-094.

U.S. EPA, Undated. “Methane to Markets International Coal Mine Methane Projects Database,” URL: http://www2.ergweb.com/cmm/index.aspx.

U.S. EPA. Natural Gas STAR Program. “Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems”. www.epa.gov/gasstar/documents/ll_rodpack.pdf

U.S. EPA. Natural Gas STAR Program. “Lessons Learned: Replacing Glycol Dehydrators with Desiccant Dehydrators”. www.epa.gov/gasstar/documents/ll_desde.pdf

U.S. EPA. Natural Gas STAR Program. “Lessons Learned: Vapor Recovery Tower/VRU Configuration”. www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf

U.S. EPA. Natural Gas STAR Program. Draft EPA Lessons Learned – Reduced Emissions Completions

United States Code of Federal Regulations, 40 CFR Part 144, Underground Injection Control Program (as of 22 July 2009)

United States Code of Federal Regulations, 40 CFR Part 146, Underground Injection Control Program: Criteria and Standards (as of 22 July 2009)

US EPA. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13: Miscellaneous Sources. www.epa.gov/ttnchie1/ap42/ch13/final/c13s05.pdf

Vera, Sergio Armando Jerez, December 2006. Using multi-layer models to forecast gas flow rates in tight gas reservoirs, Thesis for Master of Science in Petroleum Engineering, Texas A&M University.

Warpinski, N.R, “Patent for apparatus and method for monitoring underground fracturing,” U.S. Patent number: 5934373, Issued 10 August 1999.

Warpinski, N.R., James E. Uhl, and Bruce P. Engler, 1997. “Review of Hydraulic Fracture Mapping Using Advanced Accelerometer-Based Receiver Systems.”

Wiley, C., Bob Barree, Mike Eberhard, and Tom Lantz, 2004. “Improved Horizontal Well Stimulations in the Bakken Formation, Williston Basin, Montana,” Prepared for SPE Annual Technical Conference and Exhibition, Houston, Texas, September 25-29, 2004.

Willberg, D. M., R.J. Card, L.K. Britt, M. Samuel, K.W. England, L. Cawiezel, and H. Krus, ”Determination of the effect of formation water on fracture fluid cleanup through field testing in the East Texas Cotton Valley,” SPE annual technical conference, San Antonio TX, 5-8 October 1997.

Wyoming DEQ Air Quality Division. Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance. June 1997. August 2007 revision

Yesterday, Today and Tomorrow,” Summer NAPE 2008, Houston, Texas.

Zhang, Lianyang, 2005. Engineering Properties of Rocks, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

NTC

1980 N.Y. Op. Atty. Gen. (inf.) 209 – Office of the Attorney General State of New York Informal Opinion. (August 11, 1980)

Adverse Impact Reduction – Stepping Lightly: Reducing the Environmental Footprint of Oil and Gas Production. Interstate Oil & Gas Compact Commission (undated)

Adverse Impact Reduction Handbook – Reducing Onshore Natural Gas & Oil Exploration and Production Impacts Using a Broad-Based Stakeholder Approach. Interstate Oil & Gas Compact Commission (2008)

Air Emissions and Regulations Fact Sheet. Chesapeake Energy (March 2009)

An Enduring Resource: A Perspective on the Past, Present and Future Contributions of the Barnett Shale and the Economy of Fort Worth and Surrounding Areas. Perryman Group, The (March 2009)

AOTSNY - Sample Weight Limit Local Laws. (web posting undated)

Appalachian Basin Black Shale Exploitations: Past, Present, and Future. (Power Point Presentation) John Gottschling, Regional Tech. Rep. BJ Services Company, U.S.A. (5/16 & 5/17, 2007)

Bedford, Texas – Drilling Ordinance Comparison Sheet. (undated)

Better With the Shale Than Without. Press Release: Fort Worth Chamber of Commerce (3/11/09)

BLM Q & A Fact Sheet – Roan Plateau Planning Area – Reasonable Foreseeable Development (RFD) 10/24/04)

Bounty from Below – The Impact of Developing Natural Gas Resources Associated with Barnett Shale. Perryman Group, The (May 2008)

Bounty from Below: The Impact Associated with the Barnett Shale on Business Activity in Fort Worth and the Surrounding 14-County Area. The Perryman Group, May 2007.

Chesapeake Energy – Natural Gas Development & Production – Marcellus Shale, J.E. Grey May 14, 2009.

Chesapeake Quick News (Newsletter). (October 2008)

Chesapeake/Statoil Hydro – Marcellus Black Shale. Steinar Eikaas, et al (November 2008)

City of Fort Worth, Texas – Gas Drilling Ordinance. (2008)

Colorado – House Bill 07-1252 – Concerning the Accommodation of the Rights of Surface Owners with Respect to Oil and Gas Operators. (Date____).

Community Safety and Emergency Response Fact Sheet. Chesapeake Energy (March 2009)

Disposal of Spent Drilling Fluids to Publically Owned Treatment Works (POTW's). Alan A. Fuchs, NYSDEC – Division of Water (10/21/08)

Economic Impact of Barnett. Perryman Group, The (undated power point slide)

Economic Impact of the Fayetteville Shale in White County, Arkansas, The. Kathy Deck, Sam M. Walton College of Business (2008)

Economic Impact of the Oil & Gas Industry in Pennsylvania, The. Pennsylvania Economic League. (November 2008)

Economic Workforce Brief – Forecast of the Potential Impact of Increased Royalty Income on the Pennsylvania Economy 2008-1.1 (June 2008)

Environmental Resources for Tribal Energy Development – Office of Indian Energy and Economic Development. Tribal Energy and Environmental Information Clearing House (undated web site).

Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs. J. Daniel Arthur, et al (2008)

Experience in Sublette County. Penn State, Ecosystem Research Group (undated power point slide)

Farmers Branch Texas – Ordinance #2946 Regulating Well Drilling. (undated)

Flower Mound Texas – Oil and Gas Drilling Ordinance Comparison Chart. (May 2007)

Forest Landowners & Natural Gas Development, Marcellus Education Fact Sheet – Penn State, College of Agriculture (2008)

Forestry – Press Release. Pennsylvania DOC – NRB (2008)

Fortuna NY DEC SGEIS Response, Rick Kessy, Fortuna Energy (May 27, 2009)

Fractured Shale Gas Potential in New York – David G. Hill and Tracy E. Lombardi & John P. Martin – undated

Gas Rights and Right of Way Leasing Pointers for Forest Owners. Cornell Cooperative Extension (12/15/08)

Gas Well Drilling Noise Impacts and Mitigation Study. Behiens and Associates, Inc. (April 2006)

Geological and Activity Overview of Appalachian Plays (Power Point Presentation). Dan A. Billman, P.G. CPG. April 2008)

Goldbook, 4th Edition, revised 2007 – Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development. Bureau of Land Management (2007)

Hearing on The Environmental Impact of Drilling and Development of Natural Gas. Memo to NYS Assembly – Michael P. Joy, PhD. Esq. (10/16/08)

Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale. Daniel Arthur, P.E., et al (9/21/08)

Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale. Groundwater Protection Council (9/23/08)

Information Gathering on Hydraulic Fracturing of Shale Formation for Gas Production. G. Struyk., Fortuna Energy, Inc. (8/14/08)

Jonah/Anticline Fields Direct Workforce Through Three Phases. Penn State, Ecosystem Research Group (undated power point slide)

Kentucky Erosion Prevention and Sediment Control Field Guide: Kentucky Division of Water Nonpoint Source Section and Kentucky Division of Conservation.

Low Risk Site Handbook for Erosion Potential and Sediment Control: Vermont Department of Environmental Conservation (2006)

Marcellus Shale Hydraulic Fracturing Fact Sheet. Chesapeake Energy (March 2009)

Marcellus Shale Play's Vast Resource Potential. T. Engelder & G. Lash (May 2008)

Modern Shale Gas Development in the U.S., A Primer. U.S. Department of Energy, Office of Fossil Energy (April 2009)

Natural Gas and Local Governments. Timothy Kelsey, PhD, Penn State Cooperative Extension (2009)

New York State – Open Space Conservation Plan (2006)

Notice of Change to City of Grand Prairie, Texas – Code of Ordinances – Summary. (5/6/08)

Notice of Determination of Non-Significance – API# 31-015-2290-00, Permit 08828 (February 13, 2002).

NYS Vehicle Traffic Law §1660 – Weight Limits on Town Roads. (undated)

NYS-DEC Policy DEP-00-1 – Assessing and Mitigating Noise Impacts (10/06/00 – Last Revised 02/02/01)

NYS-DEC Policy DEP-00-2 – Assessing and Mitigating Visual Impacts (7/31/00)

Oil & Gas Lease Sale - Pennsylvania DOC – NRB – Forestry. (September 2008)

Oil & Gas Position Statement. Pennsylvania DOC – NRB – Forestry (April 1, 2008)

Oil & Gas Program (slide show). Pennsylvania DOC – NRB – Forestry (2008)

Potential Development of the Natural Gas Resources in the Marcellus Shale – New York, Pennsylvania, West Virginia & Ohio. (National Park Service – U.S. Department of the Interior – December 2008)

Potential Development of the Natural Resources in the Marcellus Shale (New York, Pennsylvania, West Virginia & Ohio). National Park Service – U.S. Department of the Interior (December 2008).

Potential Economic Impacts of Marcellus Shale in Pennsylvania. Timothy W. Kelsey, PhD, Penn State Cooperative Extension – (2009)

Potential Environmental Impacts Associated with Proposed Marcellus Shale Wells. Talismann Energy, Linda Collart, Mineral Resources Supervisor (7/3/08).

Preparing for Natural Gas Development: Understanding Impacts and Protecting Public Assets. Gas Drilling Task Force, The: (2/13/09)

Projecting the Economic Impact of the Fayetteville Shale Play (2008-2012). Sam M. Walton College of Business (March 2008)

Projecting the Economic Impact of the Fayetteville Shale Play 2005 – 2008. Sam M. Walton College of Business. (May 2006)

Protecting Water, Producing Gases. Mary Griffiths, Pembina Institute, Alberta Canada. (April 2007).

Reasonably Foreseeable Development Report – Roan Plateau (Question and Answer Fact Sheet). Bureau of Land Management (2004)

Reasonably Foreseeable Development Scenario for Oil & Gas (RFD) "Life of Area" Forecast for ultimate development of lease - Bureau of Land Management (2004)

Reasonably Foreseeable Development Scenario for Oil and Gas Activities In the BLM White River Field Office. Bureau of Land Managment (Executive Summary, Undated).

Responses to Notice of Incomplete Applications. Chesapeake Energy (3/9/09)

Responses to NY DEC SGEIS Information Requests. Chesapeake Energy (June 4, 2009)

Responses to NYDEC SGEIS Informational Request. East Resources. (5/21/09)

Responses to NYDEC SGEIS Informational Request. Fortuna (5/22/09)

Responses to NYDEC SGEIS Informational Request. Seneca (6/3/09)

Revised Policy for Reasonably Foreseeable Development Scenarios for Oil & Gas. Bryce Baslan, Division of Fluid Minerals (2008)

Roan Plateau Fact Sheet – Impacts of Oil and Gas Drilling. (7/7/04)

Rural Development Paper No. 43 – Energy Boomtowns & Natural Gas. Jeffrey Jacquet, NERCRD. (January 2009)

Santa Fe County Oil & Gas Amendment to the Santa Fe County Land Development Code. Ordinance No. 2008-19 (12/10/08)

Schlumberger – Shale Gas: Explanation of Gas Shale – Barnett Shale in the Fort Worth Basin, Texas (2005)

Shale Gas, Focus on the Marcellus Shale. Oil & Gas Accountability Project/Earthworks (June 2008)

Statement to Senate Environmental Resources and Energy Committee. Pennsylvania DOC – NRB – Forestry (2008)

Stepping Lightly: Reducing the Environmental Footprint of Oil & Gas Production. Interstate Oil & Gas Compact Commission (2008)

Summary of Public Comments on Natural Gas Leasing. Pennsylvania DOC – NRB – Forestry (2008)

Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development "Gold Book" United States Department of the Interior - BLM Fourth Edition – Revised 2007

Testimony of Michael P. Joy, Ph.D., Esq. – Hearings on the Environmental Impact of Drilling and Development of Natural Gas in New York State. (10/16/08)

Water Fact Sheet #28, Gas Drilling & Your Private Water Supply. Penn State, School of Forestry (2009)

Water Use in Marcellus Deep Shale Gas Exploration Fact Sheet. Chesapeake Energy (March 2009)

Well Drilling Details – Gas Ranch Storage Project – Appendix A.6 (undated untitled)

Well Permit Issuance for Horizontal Drilling. NYSDEC – Final Scoping Document (2009)

URS Corporation

All Consulting, LLC (2008). Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs, presented at International Petroleum & Biofuels Environmental Conference Albuquerque, NM, November 11-13, 2008.

Anastas, P. and J. C. Warner (1998). Green Chemistry: Theory and Practice. Oxford University Press: New York. 152 pp.

ASWCMC {June 30, 2008) Appalachian Shale Water Conservation and Management Committee.

Cameron, C., A. Florence, and C. Temple (2004). Water-Based Drilling Fluid Helps Achieve Oil-Mud Performance. AADE-04-DF-HO-01. Presented at the AADE 2004 Drilling Fluids Conference, Houston, Texas, April 6-7, 2004.

CDX Gas (2007). About Z-Pinnate Technology, at http://www.cdxgas.com/technology.php.

Cefas (visited April 2009). Description of Offshore Chemical Notification Scheme (OCNS), at http://www.cefas.co.uk/offshore-chemical-notification-scheme-(ocns).aspx

Cobby, G. L. and R. J. Craddock (1999). Western Australian Government Decision-Making Criteria Involved In the Regulation of Drilling Fluids Offshore. APPEA Journal, pp 600-605.

D. B. Burnett Global Petroleum (visited April 2009). Undated. Environmentally Friendly Drilling Systems Background & Current Programs, at http://www.bismarckstate.edu/gpee/presentations/pdfs/BurnettDaveGPEEPresentation.pdf.

Division of Water (June 1998). Division of Water Technical and Operational Guidance Series 1.1.1. - Ambient Water Quality Standards and Guidance Values and Groundwater Effluent Limitations, at http://www.dec.ny.gov/regulations/2652.html.

Fichter, J.K. et al. (2008) Use of microbiocides in Barnett Shale gas well fracturing fluids to control bacteria related problems, presented at the National Association of Corrosion Engineers (NACE) International Corrosion 2008 Conference and Expo.

Fichter, J.K., Johnson, K., French, K. an Oden, R. 2008. "Use of Microbiocides in Barnett Shale Gas Well Fracturing Fluids to Control Bacterially-Related Problems." NACE International Corrosion 2008 Conference and Expo. Paper 08658. I pp. 2, 3. http://content.nace.org/Store/Downloads/7B772A1BA1- 6E44-DD11-889D-0017A446694E.pdf

Gas Technology Institute (September 26, 2007). Proceedings and Minutes of the Hydraulic Fracturing Expert Panel, XTO Facilities, Fort Worth, TX, compiled by Tom Hayes of GTI.

Hill et al. (undated). Fractured Shale Gas Potential in New York, prepared by David G. Hill and Tracy E. Lombardi of TICORA Geosciences, Inc., and John P. Martin of NYSERDA.

Interstate Oil and Gas Compact Commission (undated). Is Hydraulic Fracturing Safe?, at http://www.iogcc.state.ok.us/hydraulic-fracturing visited August 2009.

Journal of Petroleum Technology Online (2006). Summary of Society of Petroleum Engineers paper 102908, "Meeting the Environmental Challenge: A New Acid Corrosion Inhibitor for the Norwegian Sector of the North Sea," by M. Vorderbruggen, SPE and H. Kaarlgstad, SPE, prepared for ATCE 2006, San Antonio, TX, 24-27 September.

Kentucky Administrative Regulations: Title 401 - Energy and Environment Cabinet Department for Environmental Protection published at http://www.lrc.ky.gov/kar/TITLE401.HTM

Lustgarten, Abrahm (November 11, 2008). Does Natural-Gas Drilling Endanger Water Supplies? in Business Week November 11, 2008.

Maurice Smith (September 2008). Frac Forward: Startup Cracks Propane Fracture Puzzle, Provides 'Green' Solution, in New Technology Magazine.

National Energy Board of Canada (April 2009). Offshore Chemical Selection Guidelines for Drilling & Production Activities On Frontier Lands, at http://www.cnlopb.nl.ca/pdfs/guidelines/ocsg.pdf.

National Energy Technology Laboratory (visited April 2009). Produced Water Technology Description – Fact sheet – Ion Exchange, at http://www.netl.doe.gov/technologies/pwmis/techdesc/ionex/index.html.

National Energy Technology Laboratory: Home Page (visited June 2009). Petroleum Consulting Services Production Verification Tests, DE-AC21-90MC26025, at http://www.netl.doe.gov/technologies/oil-gas/NaturalGas/Projects_n/EP/DCS/DCS_C_26025PetrolConsult.html.

Natural Gas and Technology (2004), at http://www.naturalgas.org/environment/technology.asp.

New York State Water Resources Institute at Cornell University (visited 2009). Waste Management of Cuttings, Drilling Fluids, Hydrofrac Water and Produced Water, at http://wri.eas.cornell.edu/gas_wells_waste.html.

NUMA (visited April 2009). Undated. Project Summaries, Horizontal Drilling Project, United Kingdom. http://www.numahammers.com/newsitems/PS-EIL_shropshire.html.

NYSDEC (1992). Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (GEIS), at http://www.dec.ny.gov/energy/45912.html.

NYSDEC (visited April 2009). Protecting the Environment During Well Drilling and Operation - Environmental Protections for Oil and Gas Development, at http://www.dec.ny.gov/energy/1536.html.

NYSDEC (visited April 2009). Protecting the Environment, Water Resources and Public Water Supplies at http://www.dec.ny.gov/energy/46288.html.

NYSDEC (visited June 2009). Casing and Cementing Practices, at http://www.dec.ny.gov/energy/1757.html.

NYSDEC (visited June 2009). Classification – Surface Waters and Groundwaters (6 NYCRR 701), at http://www.dec.ny.gov/regs/4592.html#15979.

Ohio Department of Natural Resources: Mineral Resources Management (April 28, 2005). Best Management Practices for Pre-Drilling Water Sampling, at http://www.dnr.state.oh.us/Portals/11/oil/pdf/BMP_PRE-DRILLING_WATER_SAMPLING.pdf.

Parshall, J. (undated). Barnett Shale Showcases Tight-gas Development. Journal of Petroleum Technology, in: ALL Consulting. 2008. Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale.

Pennsylvania State University (2009). Gas Well Drilling and Your Private Water Supply: Water Facts #28. URL: http://resources.cas.psu.edu/WaterResources/pdfs/gasdrilling.pdf

Pennsylvania Statutes and Consolidated Statutes Annotated, Title 58 - Oil And Gas, Chapter 11 - Oil And Gas Act

Rae, P., A. N. Martin, and B. Sinanan (1999). Skin bypass fracs: Proof that size is not important. SPE annual technical conference and exhibition, 3-6 October 1999. Volume delta: Drilling and completion. SPE annual technical conference, Houston TX , ETATS-UNIS (03/10/1999) 1999, pp. 129-141 (23 ref.).

Schlumberger (visited April 2009). Earth-friendly GreenSlurry system for uniform marine performance, at http://www.slb.com/media/services/stimulation/execution/greenslurry.pdf.

Schlumberger (visited April 2009). Green Chemistry: Earth-friendly GreenSlurry system for uniform marine performance, at http://www.slb.com/content/services/stimulation/execution/greenslurry.asp

Scott M. Stringer (2009). Uncalculated Risk: How plans to drill for gas in Upstate New York could threaten New York City's water system. A report based on statement by Manhattan Borough President.

TAMU (Texas A&M University) (2003). Drilling for Natural Gas – an Environmental Friendly Process. The Texas Institute for Advancement of Chemical Technology (TIACT). October 10, 2003. http://cheweb.tamu.edu/tiact/.

USDOE (1999). Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology, prepared by the office of Fossil Energy of the United States Department of Energy.

USDOE (2009). State Oil and Natural Gas Regulations Designed to Protect Water Resources, prepared by the office of Fossil Energy of the United States Department of Energy, and the National Energy Technology Laboratory.

USEPA (2002). EPA Facts about Cesium-137. At http   www.epa.gov superfund health contaminants radiation pdfs cesium.pdf.

USEPA (2003). A Memorandum of Agreement between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation for Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells, dated 12 December 2003.

USEPA (June, 2004). Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. EPA 816-R-04-003.

USEPA (visited April 2009). Introduction to the Concept Of Green Chemistry, at http://www.epa.gov/oppt/greenchemistry/pubs/about_gc.html?.

USEPA (visited June 2009). Drinking Water Contaminant Candidate List and Regulatory Determinations, at http://www.epa.gov/OGWDW/ccl/index.html.

USEPA (visited June 2009). Drinking water contaminants, at http://www.epa.gov/safewater/contaminants/index.html.

USEPA (visited June 2009). Secondary Drinking Water Regulations: Guidance for Nuisance Chemicals, at http://www.epa.gov/OGWDW/consumer/2ndstandards.html.

USEPA (visited June 2009). Setting Standards for Safe Drinking Water, at http://www.epa.gov/ogwdw/standard/setting.html.

USEPA (visited June 2009). Six Year Review of Drinking Water Standards, at http://www.epa.gov/OGWDW/review.html.

Washington Group International (undated). Water in the West: Treatment, Disposal, and Reuse of Produced Water from Natural Gas Exploration in the Rocky Mountain Region, prepared by Tim Rollenhagen, Barry Friedman, Jeff Matthews and Sally Cuffin, of Washington Group International, Denver, CO.

Well testing information published on Kentucky Division of Water website at http://www.water.ky.gov/dw/profi/tips/welltest.htm

Wills, Jonathan (2000). A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping- Drilling Waste Streams from Offshore Oil and Gas Installations, at http://www.offshore-environment.com/drillwastestream.html.

Wills, Jonathan (2000). A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping- The Law on Offshore Wastes Discharges in Different Jurisdictions - Norway, at http://www.offshore-environment.com/norway.html

Wills, Jonathan (2000). A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping- The Law on Offshore Wastes Discharges in Different Jurisdictions, at http://www.offshore-environment.com/unitedkingdom.html.

Witter et al. (September 15, 2008). Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper, prepared by Roxana Witter, Kaylan Stinson, Holly Sackett, Stefanie Putter, Gregory Kinney, Daniel Teitelbaum, and Lee Newman.