NEW YORK STATE OF OPPORTUNITY. Department of Environmental Conservation

FINAL SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT

ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Regulatory Program for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Volume 1: Final Supplemental Generic Environmental Impact Statement

Volume 2: Response to Comments

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FINAL SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT

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EXECUTIVE SUMMARY

High-volume hydraulic fracturing utilizes a well stimulation technique that has greatly increased the ability to extract natural gas from very tight rock. High-volume hydraulic fracturing, which is often used in conjunction with horizontal drilling and multi-well pad development, raises new, significant, adverse impacts not studied in 1992 in the Department of Environmental Conservation's (Department or DEC) previous Generic Environmental Impact Statement (1992 GEIS) on the Oil, Gas and Solution Mining Regulatory Program.[1]

Since issuing a draft Scope for public review in October 2008, the Department has conducted an exhaustive evaluation of high-volume hydraulic fracturing's potential significant adverse environmental and public health impacts and possible mitigation measures to eliminate, avoid or reduce those impacts. The Department received over 260,000 public comments, an unprecedented number, on the 2009 Draft SGEIS (dSGEIS) and the 2011 Revised Draft SGEIS (rdSGEIS) and the associated regulatory documents which were considered before issuing this Final SGEIS (FSGEIS) (the drafts and the final SGEIS are collectively referred to as the "SGEIS," unless otherwise distinguished). During this period of time, a broad range of experts from academia, industry, environmental organizations, municipalities, and the medical and public health professions commented and/or provided their analyses of high-volume hydraulic fracturing. The comments referenced an increasing number of ongoing scientific studies across a wide range of professional disciplines. These studies and expert comments evidence that significant uncertainty remains regarding the level of risk to public health and the environment that would result from permitting high-volume hydraulic fracturing in New York, and regarding the degree of effectiveness of proposed mitigation measures. In fact, the uncertainty regarding the potential significant adverse environmental and public health impacts has been growing over time.

1 The Generic Environmental Impact Statement (1992 GEIS) on the Oil, Gas and Solution Mining Regulatory Program is posted on the Department's website at http://www.dec.ny.gov/energy/45912.html. The 1992 GEIS includes an analysis of impacts from vertical gas drilling as well as hydraulic fracturing. Since 1992 the Department has used the 1992 GEIS as the basis of its State Environmental Quality Review Act (SEQRA) review for permit applications for gas drilling in New York State.

The Department worked closely with the New York State Department of Health (NYSDOH) during preparation of the SGEIS. Due to the increasing concern regarding high-volume hydraulic fracturing's impacts on public health, the Department on September 20, 2012, requested NYSDOH to conduct a review of the SGEIS and mitigation measures and advise the Department whether they were adequate to protect public health. On December 17, 2014, NYSDOH advised the Department that there are several potential adverse environmental impacts that can result from high-volume hydraulic fracturing which may be associated with adverse public health outcomes. These impacts include: 1) air impacts that could affect respiratory health due to increased levels of particulate matter, diesel exhaust, or volatile organic chemicals; 2) climate change impacts due to methane and other volatile organic chemical releases to the atmosphere ; 3) drinking water impacts from underground migration of methane and/or fracturing fluid chemicals associated with faulty well construction or seismic activity; 4) surface spills potentially resulting in soil, groundwater, and surface water contamination; 5) surface water contamination resulting from inadequate wastewater treatment; 6) earthquakes and creation of fissures induced during the hydraulic fracturing stage; and 7) community character impacts such as increased vehicle traffic, road damage, noise, odor complaints, and increased local demand for housing and medical care. NYSDOH concluded that "until the science provides sufficient information to determine the level of risk to public health from HVHF to all New Yorkers and whether the risks can be adequately managed … HVHF should not proceed in New York State."

The Department concurs with NYSDOH, as the uncertainty revolving around potential public health impacts stems from many of the significant adverse environmental risks identified in the SGEIS for which the Department proposed and considered extensive mitigation measures. In response to additional scientific information regarding the magnitude of high-volume hydraulic fracturing's potential significant adverse impacts, the Department considered expanding many of the mitigation measures previously proposed in the rdSGEIS to protect public health and the environment with a greater margin of safety.

As a result, more and more area within the Marcellus Shale fairway would be off limits to high-volume hydraulic fracturing. For example, the Department considered prohibiting high-volume hydraulic fracturing on private lands within the Catskill Park, increasing setbacks to residences, and natural and cultural resources, and expanding the sensitive areas that would be off limits. The additional restrictions and prohibitions and the necessity for close and coordinated regulatory oversight by the Department with involved and interested state and local agencies would substantially increase costs to industry, which would likely negatively impact the potential economic benefits associated with high-volume hydraulic fracturing..

The Court of Appeals decision in *Matter of Wallach v. Town of Dryden and Cooperstown Holstein Corp. v. Town of Middlefield*, which held that local governments could exercise their zoning and land use jurisdiction to restrict or prohibit high-volume hydraulic fracturing within their communities, would impact prior economic projections and would likely result in a decrease in potential economic benefits. This would also create potential land use conflicts with high-volume hydraulic fracturing's ancillary infrastructure in communities that reject high-volume hydraulic fracturing within their borders.

General Background

The Department has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus Shale for natural gas production by high-volume hydraulic fracturing. In New York, the primary target for shale-gas development is currently the Marcellus Shale, with the deeper Utica Shale also identified as a potential resource. Additional low-permeability reservoirs may be considered by project sponsors for development by high-volume hydraulic fracturing.

Horizontal drilling with high-volume hydraulic fracturing facilitates natural gas extraction from large areas where conventional natural gas extraction is commercially unprofitable; thus, well operations would likely be widespread across certain regions within the Marcellus formation. Distinct from conventional natural gas extraction technologies governed by the Department's 1992 GEIS and related oil and gas permits, high-volume hydraulic fracturing involves substantially larger volumes of water and a multitude of potential chemical additives. The use of high-volume hydraulic fracturing with horizontal well drilling technology enables a number of wells to be drilled from a single well pad (multi-pad wells). Although horizontal drilling results in fewer well pads than traditional vertical well drilling, the pads are larger and the industrial activity taking place on the pads is more intense.

Hydraulic fracturing requires chemical additives, some of which potentially pose hazards to public health and the environment through exposure. The high volume of water associated with hydraulic fracturing may also result in significant adverse impacts relating to water supplies, other water resources, wastewater treatment and disposal, and truck traffic. Horizontal wells also generate greater volumes of drilling waste (cuttings) than vertical wells. The industry projections of the level of drilling, as reflected in the intense development activity in neighboring Pennsylvania, has raised additional concerns relating to community character, including noise, and visual impacts; adverse impacts on cultural and historic resources, agriculture, tourism, and scenic resources; and socioeconomics impacts.

The Department has prepared this Final Supplemental Generic Environmental Impact Statement (Final SGEIS) to satisfy the requirements of the State Environmental Quality Review Act (SEQRA) by examining high-volume hydraulic fracturing and identifying new potential significant adverse impacts of these operations.

The Department's environmental review associated with the Department's determination whether to authorize high-volume hydraulic fracturing in New York State required extensive evaluation of the current and developing science underlying high-volume hydraulic fracturing's impacts and the increasingly stringent mitigation measures to protect the environment and public health.

SEQRA Procedure to Date

The public process to develop the SGEIS began with public scoping sessions in the autumn of 2008. Since then, engineers, geologists and other scientists and specialists in all of the Department's natural resources and environmental quality programs have collaborated to comprehensively analyze a vast amount of information about the proposed operations and the potential significant adverse impacts of these operations on the environment, identify mitigation measures that would prevent or minimize any significant adverse impacts, and identify criteria and conditions for future permit approvals and other regulatory action.

In September 2009, the Department issued an initial dSGEIS (2009 dSGEIS) for public review and comment. The extensive public comments revealed a significant concern with potential contamination of groundwater and surface drinking water supplies that could result from this new stimulation technique. Concerns raised included comments that the 2009 dSGEIS did not fully study the potential for gas migration from this new technique, or adequately consider impacts from disposal of solid and liquid wastes. Additionally, commenters stated the 2009 dSGEIS did not contain sufficient consideration of visual, noise, traffic, community character or socioeconomic impacts. Accordingly, in 2010 Governor Paterson ordered the Department to issue a revised dSGEIS (rdSGEIS) on or about June 1, 2011. Executive Order 41 also provided that no permits authorizing high-volume hydraulic fracturing would be issued until the SGEIS was finalized.

Since the issuance of the 2009 dSGEIS, and the subsequent rdSGEIS, the Department has gained a more detailed understanding of the potential impacts associated with high-volume hydraulic fracturing with horizontal drilling from: (i) the extensive public comments from environmental organizations, municipalities, industry groups, medical and public health professionals, and other members of the public; (ii) its review of reports and studies of proposed operations prepared by industry groups; (iii) extensive consultations with scientists in several bureaus within the NYSDOH; (iv) the use of outside consulting firms to prepare analyses relating to socioeconomic impacts, as well as impacts on community character, including visual, noise and traffic impacts; and, (v) its review of information and data from the Pennsylvania Department of Environmental Protection (PADEP) and the Susquehanna River Basin Commission (SRBC) about events, regulations, enforcement and other matters associated with ongoing Marcellus Shale development in Pennsylvania. In June 2011, moreover, Commissioner Joseph Martens and Department staff visited a well pad in LeRoy, Pennsylvania, where contaminants had discharged from the well pad into an adjacent stream, and had further conversations with industry representatives and public officials about that event and high-volume hydraulic fracturing operations in Pennsylvania generally.

In addition, as discussed above, NYSDOH conducted a comprehensive health review of high-volume hydraulic fracturing and completed its Public Health Review in December 2014.

During preparation of this Final SGEIS, the Department incorporated suggestions made by the public and, where appropriate, provided additional discussion in either the Final SGEIS or the Response to Comments to clarify the content of the drafts. Specifically, the Department has revised Chapter 1 to reflect all of the procedural changes and actions that have occurred following the time of publication of the rdSGEIS for public comment. In Chapter 2, a subsection drafted in 2011 relating to the potential public need and benefit of high-volume hydraulic fracturing was deleted because the subject is now addressed more accurately in the Department's Response to Comments, which is based on analysis subsequent to the rdSGEIS and public comment. The Department also revised Chapter 7 of the Final SGEIS to remove conclusory language with respect to the mitigation proposed, to better reflect remaining uncertainty as to the effectiveness or the degree to which the mitigation would reduce impacts and risks associated with high-volume hydraulic fracturing. The Department also revised Chapter 9 to better represent both the benefits and negative consequences of the No Action Alternative. This Executive Summary was also revised to reflect these changes, as well as to reflect some of the additional mitigation measures that were considered by the Department. These minor changes to the SGEIS do not reflect that some laws or regulations may have changed from the time of publication of the 2011 rdSGEIS, notably, amendments to the Water Resources Law and corresponding regulations.

Pursuant to 6 NYCRR Section 617.9(b)(8), the Final SGEIS consists of the prior drafts of the SGEIS, including all revisions noted above and the summary of the substantive comments received and the Department's responses, which both comprise the Department's Response to Comments. Consequently, the findings for this action will consider the relevant environmental and public health impacts, mitigation measures and facts discussed in the Final SGEIS, prior drafts of the SGEIS, and the 1992 GEIS, including the Department's Response to Comments. The Department's Response to Comments represents the Department's most current assessment of the impacts associated with high-volume hydraulic fracturing and the effectiveness of proposed or considered mitigation measures to adequately mitigate significant adverse environmental and public health impacts.

Each chapter of this final SGEIS is summarized below.

Chapter 1 – Introduction

This Chapter contains background information and an introduction to the SGEIS.

Chapter 2 – Description of Proposed Action

This Chapter includes a discussion of the purpose of proposed high-volume hydraulic fracturing operations, as well as the potential locations, projected activity levels, and environmental setting for such operations. Information on the environmental setting focuses on topics determined during scoping to require attention in the SGEIS. The Department determined, based on industry projections in 2010 that it would potentially receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a "peak development" year, if high-volume hydraulic fracturing were authorized. Based on these projections, an average year could see 1,600 or more applications. Development of the Marcellus Shale in New York could occur over a 30-year period. A consultant to the Department completed a draft estimate of the potential economic and public benefits of proposed high-volume hydraulic fracturing development, including an analysis based on an average development scenario as well as a more conservative low potential development scenario. That analysis calculates for each scenario the total economic value to the proposed operations, potential state and local tax revenue, and projected total job creation. However, given the cost of compliance with New York State's draft high-volume hydraulic fracturing program conditions, the *Matter of Wallach v. Town of Dryden and Cooperstown Holstein Corp. v. Town of Middlefield* decision, the areas where high-volume hydraulic fracturing would be prohibited or restricted by the SGEIS, and the economics of oil and gas production, the Department cannot with any certainty predict how many applications would be submitted if high-volume hydraulic fracturing were authorized. However even with a reduced economic outlook, it remains likely that high-volume hydraulic fracturing would be widespread and would impact areas that previously have not been exposed to oil and gas development. In fact, if high-volume hydraulic fracturing were authorized, the proposed restrictions and prohibitions in certain areas would likely lead to intensified development in those areas where high-volume hydraulic volume would be permissible. Moreover, as discussed below, beyond directly impacting those particular areas where the activity would be allowed, the ancillary activities associated with high-volume hydraulic fracturing and their corresponding significant adverse impacts would likely spread to those areas of the State where high-volume hydraulic fracturing is prohibited.

Chapter 3 – Proposed SEQRA Review Process

This Chapter describes how the Department would use the 1992 GEIS and the Final SGEIS in reviewing applications to conduct high-volume hydraulic fracturing operations in New York State if high-volume hydraulic fracturing were authorized. It describes the proposed Environmental Assessment Form (EAF) addendum requirements that would be used in connection with high-volume hydraulic fracturing applications, and also identifies those potential activities that would require site-specific SEQRA determinations of significance after the SGEIS is completed. Specifically, Chapter 3 states that site-specific environmental assessments and SEQRA determinations of significance would be required for the following types of high-volume hydraulic fracturing applications, regardless of the target formation, the number of wells drilled on the pad and whether the wells are vertical or horizontal (the Department considered expanding some of the distances listed below):

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

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

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

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

5) 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

6) Any proposed well location determined by the New York City Department of Environmental Protection (NYCDEP) to be within 1,000 feet of its subsurface water supply infrastructure.

In all of the aforementioned circumstances a site-specific SEQRA assessment would be required because such application is either beyond the scope of the analyses contained in this draft SGEIS or the Department has determined that proposed activities in these areas raise additional environmental issues that necessitate a site-specific review. Many of the issues for which the Department determined that a site-specific environmental assessment and SEQRA determination of significance would be required represent areas of heightened environmental concern where environmental impacts could be expected to be significant. As indicated previously, the Department continued its evaluation of more stringent conditions to address both the uncertainty regarding the potential impacts and the impacts that remain unresolved due to the potential inadequacy of mitigation measures. The Department weighed additional conditions to address programmatic concerns as the public comment and scientific studies revealed an expanding bibliography of scientific uncertainty and unresolved and unmitigated environmental impacts.

In addition to those site-specific SEQRA assessments described in Chapter 3, the Department considered requiring site-specific environmental assessments and SEQRA determinations of significance for the following additional types of high-volume hydraulic fracturing applications:

1) Any proposed centralized flowback water surface impoundment;

2) Any proposed well location within a contiguous, 30-acre, high- or medium-scoring grassland patch in a grassland focus area unless the ecological assessment demonstrates lack of a significant adverse impact on grassland habitat and grassland birds;

3) Any proposed well location within a contiguous, 150-acre forest patch in a forest focus area unless the ecological assessment demonstrates lack of a significant adverse impact on forest interior habitat and forest interior birds;

4) Any proposed well location on private lands that are totally surrounded by New York State Office of Parks, Recreation and Historic Preservation (OPRHP) lands or Department-administered State-owned lands;

5) Any proposed well location within the Catskill Park outside the New York City watershed or the Adirondack Park; and

6) Any proposed well location wholly or partially within or substantially contiguous to an historic district.

The Department also considered expanding the buffers of some of the previously proposed locations requiring a site-specific review, including expanding the 150-foot buffer from a perennial or intermittent stream, storm drain, lake or pond to 300 feet and including freshwater wetlands, and converting some of the requirements for site-specific reviews to prohibitions.

Chapter 3 also identifies the Department's oil and gas well regulations, located at 6 NYCRR Part 550, and it discusses the existence of other regulations related to high-volume hydraulic fracturing. The Department proposed revised regulations relating to high-volume hydraulic fracturing in 2011 but abandoned the rulemaking in 2013.

Chapter 4 - Geology

Chapter 4 supplements the geology discussion in the 1992 GEIS (Chapter 5) with additional details about the Marcellus and Utica Shales, seismicity in New York State, naturally occurring radioactive materials (NORM) in the Marcellus Shale and naturally occurring methane in New York State.

Chapter 5 - Natural Gas Development Activities & High-Volume Hydraulic Fracturing

This Chapter comprehensively describes the activities associated with high-volume hydraulic fracturing and multi-well pad drilling, including the composition of hydraulic fracturing additives and flowback water characteristics. It is based on the 2011 description of proposed activities provided by industry and verified by the Department in addition to being informed by high-volume hydraulic fracturing operations ongoing in Pennsylvania and elsewhere. In this Chapter, the average disturbance associated with a multi-well pad, access road and proportionate infrastructure during the drilling and fracturing stage is estimated at 7.4 acres, compared to the average disturbance associated with a well pad for a single vertical well during the drilling and fracturing stage, which is estimated at 4.8 acres. As a result of required partial reclamation, the average well pad would generally be reduced to averages of about 5.5 acres and 4.5 acres, respectively, during the production phase.

This Chapter describes the process for constructing access roads, and observes that because most shale gas development would consist of several wells on a multi-well pad, more than one well would be serviced by a single access road instead of one well per access road as was typically the case when the 1992 GEIS was prepared. Therefore, in areas developed by horizontal drilling using multi-well pads, it is expected that fewer access roads as a function of the number of wells would be constructed. Industry estimates that 90% of the wells used to develop the Marcellus Shale would be horizontal wells located on multi-well pads. However, the evolution of the technology that facilitates extraction of natural gas from deep low-permeability shale formations where it was previously not feasible would lead to more widespread impacts in certain regions that could not occur from conventional methods of extraction. Chapter 5 describes the constituents of drilling mud and the containment of drill cuttings, either in a lined on-site reserve pit or in a closed-loop tank system. This Chapter also calculates the projected volume of cuttings and the potential for such cuttings to contain naturally occurring radioactive materials (NORM).

This Chapter also discusses the process of high-volume hydraulic fracturing, the composition of fracturing fluid, on-site storage and handling, and transport of fracturing additives. The high-volume hydraulic fracturing process involves the controlled use of high volumes of water and chemical additives, pumped under pressure into a steel-cased and cemented wellbore. To protect fresh water zones and isolate the target hydrocarbon-bearing zone, high-volume hydraulic fracturing does not occur until after the well is cased and cemented, and typically after the drilling rig and its associated equipment are removed from the well pad. Chapter 5 explains that the Department would generally require at least three strings of cemented casing in the well during fracturing operations. The outer string (i.e., surface casing) would extend below fresh ground water and would have been cemented to the surface before the well was drilled deeper. The intermediate casing string, also called protective string, is installed between the surface and production strings. The innermost casing string (i.e., production casing) typically extends from the ground surface to the toe of the horizontal well.

The fluid used for high-volume hydraulic fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid. 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 and those additives are identified and discussed in detail in Chapter 5. 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 typical 4,000-foot lateral wellbore. 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.

After the high-volume 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 (typically sand) to flow up through the wellbore to the surface. Both the process and the returned water are commonly referred to as "flowback." The SGEIS estimates flowback water volume to range from 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons. After completion of drilling operations and while natural gas production is underway, brine fluids that preexisted naturally in the formation prior to drilling are returned to the surface from the borehole, which is commonly referred to as "production brine." It is estimated that production brine per well may range from 400 gallons per day (gpd) to 3,400 gpd. Chapter 5 discusses the volume, characteristics, recycling and disposal of flowback water and production brine.

Chapter 6 – Potential Environmental Impacts

This Chapter identifies and evaluates the potential significant adverse impacts associated with high-volume hydraulic fracturing operations and, like other chapters, should be read as a supplement to the 1992 GEIS. The Department's evolving understanding of the potential significant adverse impacts associated with high-volume hydraulic fracturing is reflected in the accompanying Response to Comments, which represents the Department's current assessment of those impacts and of the effectiveness of proposed or considered mitigation measures. In this regard, the ever increasing collection of proposed mitigation measures demonstrates three essential weaknesses of the proposed program: (1) the effectiveness of the mitigation is uncertain; (2) the potential risk and impact from the proposed Action to the environment and public health cannot be quantified at this time, and (3) there are some significant adverse impacts that are simply unavoidable.

Water Resources Impacts

The Department recognizes the importance of protecting New York's water resources for drinking water supplies, economic development, agriculture, recreation and tourism. As memorialized in Environmental Conservation Law (ECL) § 15-0105, the Department must require the use of all known available and reasonable methods to protect and preserve the purity and quality of water resources over the long-term in order to serve public health, safety and welfare and to maintain ecological resources. Potential significant adverse impacts on water resources exist with regard to potential degradation of drinking water supplies; impacts to surface and underground water resources due to large water withdrawals for high-volume hydraulic fracturing; cumulative impacts; stormwater runoff; surface spills, leaks and pit or surface impoundment failures; groundwater impacts associated with well drilling and construction and seismic activity; waste disposal; and New York City's subsurface water supply infrastructure.

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies away from the well site or through new or existing water-supply wells drilled into aquifers. Chapter 6 concludes that, without proper controls on the rate, timing and location of such water withdrawals, the cumulative impacts of such withdrawals could cause modifications to groundwater levels, surface water levels, and stream flow that could result in significant adverse impacts, including but not limited to impacts to the aquatic ecosystem, downstream river channel and riparian resources, wetlands, and aquifer supplies.

Using an industry estimate of a yearly peak activity in New York of 2,462 wells, the SGEIS estimates that high-volume hydraulic fracturing would result in a calculated peak *annual* fresh water usage of 9 billion gallons. Total *daily* fresh water withdrawal in New York has been estimated at about 10.3 billion gallons. This equates to an annual total of about 3.8 trillion gallons. Based on this calculation, at peak activity high-volume hydraulic fracturing would result in increased demand for fresh water in New York of 0.24%. Thus, water usage for high-volume hydraulic fracturing represents a very small percentage of water usage throughout the state. Nevertheless, as noted, the cumulative impact of water withdrawals, if such withdrawals were temporally proximate and from the same water resource, could potentially be significant.

Chapter 6 also describes the potential significant adverse impacts on water resources from stormwater runoff associated with the construction and operation of high-volume hydraulic fracturing well pads. 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. Proposed mitigation measures to reduce significant adverse impacts from stormwater runoff are described in Chapter 7. Nonetheless, the potential for significant cumulative as well as site-specific impacts resulting from uncontained contaminated runoff remains.

The SGEIS concludes that spills or releases in connection with high-volume hydraulic fracturing could have significant adverse impacts on water resources. The SGEIS identifies a significant number of contaminants contained in fracturing additives, or otherwise associated with high-volume hydraulic fracturing operations. 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. Proposed mitigation measures to reduce significant adverse impacts from spills and releases are described in Chapter 7.

Chapter 6 also assesses the potential significant adverse impacts on groundwater resources from well drilling and construction associated with high-volume hydraulic fracturing. Those potential impacts include impacts from turbidity, fluids pumped into or flowing from rock formations penetrated by the well, and contamination from natural gas present in the rock formations penetrated by the well. Because of the concentrated nature of the activity on multi-well pads, the larger fluid volumes and pressures associated with high-volume hydraulic fracturing and likely cumulative impacts across the area where high-volume hydraulic fracturing would be employed, an unacceptable level of uncertainty remains as to the degree of protection afforded by the enhanced procedures and mitigation measures that the Department evaluated and which are discussed in Chapter 7.

The SGEIS explains that the potential migration of natural gas to a water well, which 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, was addressed in the 1992 GEIS. Gas migration most likely would be the result of poor well construction (i.e., casing and cement problems). As with all gas drilling, well construction practices mandated in New York are engineered in a manner that would reduce the risk of gas migration.

Subsequent to the publication of the rdSGEIS, the Department considered public comment and evolving scientific knowledge associated with seismicity and faults and the opportunities for contamination to migrate to groundwater and potable water supplies. Impacts to water resources may occur due to underground vertical migration of fracturing fluids through the shale formations, specifically through preexisting faults or abandoned gas wells. Pathways may exist for upward migration of fracturing fluids and/or natural gas through the shale formations.

Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and production brine, although classified as non-hazardous industrial waste, must be hauled under a New York State Part 364 waste transporter permit issued by the Department. Furthermore, as discussed in Chapter 7, environmental risks posed by the improper discharge of liquid wastes would be addressed through the institution of a waste tracking procedure similar to that which is required for medical waste. However, the Department recognizes that horizontal wells associated with high-volume hydraulic fracturing produce significantly more drilling and fracturing fluids, cuttings, flowback water and production brine, and result in an increase in the duration of use of pit liners. This increase in the volume of waste consequently creates greater waste disposal impacts, including the risk of inadequate disposal options and the likelihood of spills from accidents occurring during the transportation of this waste. Information about traffic management related to high-volume hydraulic fracturing is discussed in Chapter 7.

The disposal of flowback water and production brine could cause significant adverse impacts. Residual fracturing chemicals and naturally-occurring constituents from the rock formation could be present in flowback water and production brine and could result in 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. Mitigation measures have been identified that would attempt to reduce potential significant adverse impact from flowback water and production brine or treatment of other liquid wastes associated with high-volume hydraulic fracturing.

The potential for significant adverse environmental impacts from any proposal to inject flowback water and production brine from high-volume hydraulic fracturing into a disposal well would 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.

The 1992 GEIS summarized 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. Those potential impacts would also result from high-volume hydraulic fracturing operations but the potential impacts could be significantly greater. Severe flooding is described as one of the ways that bulk supplies such as additives "might accidentally enter the environment in large quantities." Mitigation measures that attempt to reduce the significant adverse impacts from floods are identified and recommended in Chapter 7.

Gamma ray logs from deep wells drilled in New York over the past several decades show the Marcellus Shale to be higher in radioactivity than other bedrock formations including other potential reservoirs that could be developed by high-volume hydraulic fracturing. However, based on the analytical results from field-screening and gamma ray spectroscopy performed on samples of Marcellus Shale, NORM levels in cuttings are similar to those naturally encountered in the surrounding environment. During production associated with high-volume hydraulic fracturing, however, radioactivity originating in wastewater may become more concentrated in pipe scale and liquid waste treatment residuals and may require additional mitigation.

As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impacts 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 that could impact integrity of a liner system, unless the cuttings are directed into tanks as part of a closed-loop tank system.

Impacts on Ecosystems and Wildlife

The SGEIS also analyzes the potential significant adverse impacts on ecosystems and wildlife from high-volume hydraulic fracturing operations. Four areas of concern related to high-volume hydraulic fracturing are: (1) fragmentation of habitat; (2) potential transfer of invasive species; (3) impacts to endangered and threatened species; and (4) use of State-owned lands.

The SGEIS concludes that high-volume hydraulic fracturing operations would have a significant adverse impact on the environment because such operations have the potential to draw substantial development into New York, which would result in unavoidable impacts to habitats (fragmentation, loss of connectivity, degradation, etc.), species distributions and populations, and overall natural resource biodiversity. Habitat loss, conversion, and fragmentation (both short-term and long-term) would result from land grading and clearing, and the construction of well pads, roads, pipelines, and other infrastructure associated with gas drilling. Possible mitigation measures are identified in Chapter 7.

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. The introduction of terrestrial and aquatic invasive species would have a significant adverse impact on the environment.

State-owned lands play a unique role in New York's landscape because they are managed under public ownership to allow for sustainable use of natural resources, provide recreational opportunities for all New Yorkers, and provide important wildlife habitat and open space. Given the level of development expected for multi-pad horizontal drilling, the SGEIS anticipates that there would be additional pressure for surface disturbance on State lands. Surface disturbance associated with gas extraction within and adjacent to state lands could have an impact on habitats, and recreational use of the state and private lands, especially large contiguous forest patches that are valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species.

The area underlain by the Marcellus Shale includes both terrestrial and aquatic habitat for 18 animal species listed as endangered or threatened in New York State that are protected under the State Endangered Species Law (ECL 11-0535) and associated regulations (6 NYCRR Part 182). Endangered and threatened wildlife may be adversely impacted through project actions such as clearing, grading and road building that occur within the habitats that they occupy. Certain species are unable to avoid direct impact due to their inherent poor mobility (e.g., Blanding's turtle, club shell mussel). Certain actions, such as clearing of vegetation or alteration of stream beds, can also result in the loss of nesting and spawning areas.

Mitigation measures for potentially significant adverse impacts from potential transfer of invasive species or from use of State lands, and mitigation measures for potential impacts to endangered and threatened species are discussed in Chapter 7.

Impacts on Air Resources

Chapter 6 of the SGEIS provides a comprehensive list of federal and New York State regulations that apply to potential air emissions and air quality impacts associated with the drilling, completion (hydraulic fracturing and flowback) and production phases (processing, transmission and storage). The Chapter includes a regulatory assessment of the various air pollution sources and the air permitting process.

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 low-permeability gas reservoirs, an air quality modeling analysis was undertaken by the Department's Division of Air Resources (DAR). The analysis identifies the emission sources involved in well drilling, completion and production, and the analysis of source operations for purposes of assessing compliance with applicable air quality standards.

After the September 2009 draft SGEIS was published, industry provided information that: (1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and (3) centralized flowback impoundments, which are large-volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated. Based on these operational restrictions, the Department revised the limited modeling of 24 hour $PM_{2.5}$ impacts and conducted supplemental air quality modeling to assess standards compliance and air quality impacts. In addition, the Department conducted supplemental modeling to account for the promulgation of new 1-hour SO_2 and NO_2 National Ambient Air Quality Standards (NAAQS) after September 2009. The results of this supplemental modeling indicate the need for the imposition of certain control measures to achieve the NO_2 and $PM_{2.5}$ NAAQS. These measures, along with all other restrictions reflecting industry's proposed operational restrictions and recommended mitigation measures based on the modeling results, are detailed in Section 7.5.3 of the SGEIS and in the Response to Comments as proposed operation conditions to be included in well permits. As detailed in the Response to Comments, the modeling also demonstrates that high-volume hydraulic fracturing could contribute significantly to elevated ozone levels in the New York metropolitan ozone nonattainment area.

The Department also developed an air monitoring program to address potential for adverse air quality impacts beyond those analyzed in the SGEIS, which are either not fully known at this time or not verifiable by the assessments to date. The air monitoring plan would help determine and distinguish both the background and drilling-related concentrations of pertinent pollutants in the ambient air.

Air quality impact mitigation measures are further discussed in Chapter 7 of the SGEIS, including a detailed discussion of pollution control techniques, various operational scenarios and equipment that can be used to achieve regulatory compliance, and mitigation measures for well pad operations. In addition, measures to reduce benzene emissions from glycol dehydrators and formaldehyde emissions from off-site compressor stations are provided.

Greenhouse Gas Emission Impacts

All operational phases of proposed well pad activities associated with high-volume hydraulic fracturing were considered, and resulting greenhouse gas (GHG) emissions determined in the SGEIS. Emission estimates of carbon dioxide (CO_2) and methane (CH_4) are included 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 Department not only quantified potential GHG emissions from activities, but also identified and characterized major sources of CO_2 and CH_4 during anticipated operations so that key contributors of GHGs with the most significant Global Warming Potential (GWP) could be addressed, with particular emphasis placed on mitigating CH_4, with its greater GWP.

Whether the combustion of natural gas results in a net increase of GHG emissions depends on what energy sources are being displaced by natural gas. Replacing higher-emitting fuels such as coal and petroleum in the power, industry, building and transportation sectors may reduce GHG emissions. Recent research demonstrates that low-cost natural gas suppresses investment in and use of clean energy alternatives (such as renewable solar and wind, or energy efficiency), because it makes those alternatives less cost-competitive in comparison to fossil fuels. New York is also implementing a number of policies that promote the continued investment in renewables and efficiency, which should reduce the potential for gas development to pose an economic obstacle to development of renewable energy and investment in energy efficiency. In the long term, New York's policies are directed towards achieving substantial reductions in GHG emissions by reducing reliance on all fossil fuels, including natural gas.

Socioeconomic Impacts

To assess the potential socioeconomic impacts of high-volume hydraulic fracturing, including the potential impacts on population, employment and housing, three representative regions were selected. The three regions were selected to evaluate how high-volume hydraulic fracturing might impact areas with different production potential, different land use patterns, and different levels of experience with natural gas well development. All of the projections identified below relied on assumptions concerning the number of high-volume hydraulic fracturing wells that would be drilled in a year without reference to the buffers and prohibitions proposed in the SGEIS or to the Court of Appeals' decision in the *Matter of Wallach v. Town of Dryden and Cooperstown Holstein Corp. v. Town of Middlefield* and without reference to changes that have occurred in the energy market since this analysis was completed. The current circumstances reduce the projections of economic benefits for the regions where high-volume hydraulic fracturing would likely occur. In fact, the assumptions concerning the number of high-volume hydraulic fracturing wells that would be drilled, and thus, economic benefits initially projected in the dSGEIS do not accurately reflect the current energy market, the high cost of adherence to the conditions that would have been imposed in New York State if high-volume hydraulic fracturing were authorized and the patchwork of local laws and land use controls that prohibit development. Therefore, such benefits would be significantly less than projected in this SGEIS, as explained in the Response to Comments.

Region A consists of Broome, Chemung and Tioga County. Region B consists of Delaware, Otsego and Sullivan County, and Region C consists of Cattaraugus and Chautauqua County. Using a low and average rate of development based on industry estimates, high-volume hydraulic fracturing could potentially have a positive economic effect where the activity takes place.

There would potentially be positive impacts on income levels in the state as a result of high-volume hydraulic fracturing. Employee earnings from operational employment were expected to range from $121.2 million under the low-development scenario to $484.8 million under the average-development scenario in Year 30. Indirect employee earnings were anticipated to range from $202.3 million under the low-development scenario to $809.2 million under the average-development scenario in Year 30. However, as discussed above, given the expected cost of compliance with New York State's draft high-volume hydraulic fracturing program conditions, the economics of oil and gas production and the areas where high-volume hydraulic fracturing would be prohibited or restricted these earnings and employment figures would be significantly lower. Chapter 6 details how the potential job creation and employee earnings might be distributed across the three representative regions.

Chapter 6 also assesses the potential temporary and permanent population impacts on each of the three selected regions, finding that Region A will experience an estimated 1.4% increase in the region's total population the first decade after high-volume hydraulic fracturing is introduced. The population of Region C is projected to be more modestly impacted by high-volume hydraulic fracturing.

While potentially providing positive impacts in the areas of employment and income, high-volume hydraulic fracturing could cause adverse impacts on the availability of housing, especially temporary housing such as hotels and motels. In Region A, where the use of high-volume hydraulic fracturing is expected to be initially concentrated, there could be shortages of rental housing. High-volume hydraulic fracturing would also bring both positive and negative impacts on state and local government spending. Increased activity could result in increases in local tax revenues and increases in the receipt of production royalties but would also result in an increased demand for infrastructure repair and local services, including emergency response services.

Visual, Noise and Community Character Impacts

The construction of well pads and wells associated with high-volume hydraulic fracturing will result in adverse impacts relating to noise. In certain areas the construction and development activities would also result in visual impacts. Potential mitigation measures to address such impacts if high-volume hydraulic fracturing were authorized are summarized in Chapter 7.

The cumulative impact of well construction activity and related truck traffic would cause impacts on the character of the rural communities where much of this activity would take place. Despite the recent New York Court of Appeals in *Matter of Wallach v. Town of Dryden and Cooperstown Holstein Corp. v. Town of Middlefield* that found that ECL Section 23-0303(2) does not preempt communities with adopted zoning laws from prohibiting or restricting the use of land for high-volume hydraulic fracturing drilling, it is likely that localities still may not be able to prevent cross boundary cumulative impacts to their respective community character. Even were a community to prohibit drilling, it is reasonably foreseeable that regional impacts related to high-volume hydraulic fracturing activities, including truck traffic, visual impacts, and impacts on cultural, historic, agricultural, tourism, and scenic resources would adversely affect neighboring municipalities that enact zoning prohibitions.

Transportation Impacts

The introduction of high-volume hydraulic fracturing has the potential to generate significant truck traffic during the construction and development phases of the well. The cumulative impact of this truck traffic has the potential to result in significant adverse impacts on local roads and, to a lesser extent, state roads where truck traffic from this activity is concentrated. It is not feasible to conduct a detailed traffic assessment given that the precise location of well pads is unknown at this time. However, such traffic has the potential to damage roads and impact air quality. Chapter 7 discusses the potential mitigation measures to address such impacts, including the requirement that the applicant develop a Transportation Plan that sets forth proposed truck routes, surveys road conditions along those routes and requires local road use agreements to address any impacts on local roads.

Additional NORM Concerns

Based upon currently available information it is anticipated that flowback water would not contain levels of NORM of significance, whereas production brine could contain elevated NORM levels. Although the highest concentrations of NORM are in production brine, 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 (pipe scale and sludge) has the potential to cause a significant adverse impact because it could expose workers handling (cleaning or maintenance) the pipe to unsafe radiation levels. Also, wastes from the treatment of production brine may contain concentrated NORM and, if so, controls would be required to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with applicable regulatory requirements.

Seismicity

There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. The information on the potential seismic impacts from high-volume hydraulic fracturing has increased since the release of the rdSGEIS. A recent study (Skoumal, 2015) ascribed a series of earthquakes in Poland, Ohio to high-volume hydraulic fracturing operations. Between March 4 and March 12, 2014, 77 earthquakes, ranging between 1.0 and 3.0

in magnitude, were identified and found to be closely related spatially and temporally to hydraulic fracturing operations at a nearby well. The Department's review of available information indicates unanswered questions remain on the seismic impacts associated with high-volume hydraulic fracturing. The Department would need to evaluate the risk to the public, infrastructure, and natural resources from induced seismicity related to hydraulic fracturing if this activity were authorized.

Chapter 7 – Mitigation Measures

This Chapter describes the measures the Department identified as of 2011 to address the potentially significant adverse impacts from high-volume hydraulic fracturing operations if high-volume hydraulic fracturing were authorized. However, there is currently insufficient scientific information to conclude that this activity can be undertaken without posing unreasonable risk to public health, and to determine what mitigation measures provide a level of assurance that potential risks have been satisfactorily minimized.

The Department recognizes the importance of protecting New York's surface and groundwater for drinking water supplies, economic development, and agriculture. In recognition of the potential for spills or releases in connection with high-volume hydraulic fracturing, the Department considered, as a general matter, requiring that operators develop and implement a groundwater monitoring program to detect potential spills and releases around the high-volume hydraulic fracturing well pad and to detect potential contamination in groundwater.

The following describes some of the mitigation measures that were evaluated in the SGEIS, as well as additional measures that were considered:

No High-Volume Hydraulic Fracturing Operations in the New York City and Syracuse Watersheds

In April 2010, the Department concluded that due to the issues presented by high-volume hydraulic fracturing operations within the drinking watersheds for the City of New York and Syracuse, the SGEIS would not apply to activities in those watersheds. Those areas present issues that primarily stem from the fact that they are unfiltered water supplies that depend on strict land use and development controls to ensure that water quality is protected. Then in 2011, the Department concluded that the proposed high-volume hydraulic fracturing activity is not consistent with the preservation of these watersheds as unfiltered drinking water supplies. Notwithstanding the mitigation measures considered for this activity, a risk remains that significant high-volume hydraulic fracturing activities in these areas could result in a degradation of drinking water supplies from accidents, surface spills, etc. Moreover, such large-scale industrial activity in these areas, even without spills, could imperil Filtration Avoidance Determinations and result in the affected municipalities incurring substantial costs to filter their drinking water supply. Accordingly, this SGEIS supports a finding that high-volume hydraulic fracturing well pads not be permitted in the Syracuse and New York City drinking water supply watersheds or in a protective 4,000-foot buffer area around those watersheds.

In response to concerns raised about infrastructure associated with the Syracuse and New York City drinking water supply watersheds, the Department considered extending its initial 4,000-foot setback from unfiltered drinking water supply watersheds for the siting of high-volume hydraulic fracturing well pads. The setback would encompass a portion of the water supply infrastructure, including tunnels that transport water for drinking supplies. Beyond that, the Department also considered prohibiting the placement of any portion of a wellbore less than 2,000 feet from any water tunnel or underneath a tunnel, and requiring enhanced site-specific review plus consultation with the municipality for any wellbore located within two miles of any water supply infrastructure for the Syracuse and NYC drinking water supplies.

No High-Volume Hydraulic Fracturing Operations on Primary Aquifers

Eighteen other aquifers in the State of New York have been identified by NYSDOH as highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems and have been designated as "primary aquifers." Because these aquifers are the primary source for many public drinking water supplies, the potential significant impacts, similar to those that would impact the New York City and Syracuse drinking water supply watersheds, must be reduced to ensure that high-volume hydraulic fracturing would not pose a threat to these critical resources and the communities that rely on them. While the Department recommended in the SGEIS that high-volume hydraulic fracturing well pads should not be permitted above a

Primary Aquifer or within a 500-foot buffer area, the impacts may be more widespread and significant than was previously considered, and consequently broader mitigation measures may be necessary.

No High-Volume Hydraulic Fracturing Operations on Certain State Lands

This SGEIS supports a finding that site disturbance relating to high-volume hydraulic fracturing operations should not be permitted on certain State lands because the potential impacts resulting from high-volume hydraulic fracturing are inconsistent with the purposes for which those lands have been acquired including public access for a wide range of recreational activities. Prohibition of high-volume hydraulic fracturing development would prevent the loss of habitat in the protected State land areas, which represent some of the largest contiguous forest patches where high-volume hydraulic fracturing activity could occur. Depending on the location of ancillary infrastructure and activities horizontal extraction of gas resources underneath State lands from well pads located outside this area may not significantly impact valuable habitat on forested State lands.

No High-Volume Hydraulic Fracturing Operations on Principal Aquifers Without Site-Specific Environmental Review

Similar to Primary Aquifers, Principal Aquifers are also highly productive. Because they are largely contained in unconsolidated material, and due to the high permeability (which allows rapid movement of groundwater) and shallow depth to the water table, both Primary and Principal Aquifers are particularly susceptible to contamination. Protection of these aquifers is critical for existing water supply needs, as well as to fulfill future needs for new or expanded water supplies. In order to reduce the risk of significant adverse impacts on these important water resources from potential surface discharges from high-volume hydraulic fracturing well pads, the SGEIS proposed that for at least two years from issuance of the final SGEIS, applications for high-volume hydraulic fracturing operations at any surface location within the boundaries of principal aquifers, or outside but within 500 feet of the boundaries of principal aquifers, would require (1) site-specific environmental assessments and SEQRA determinations of significance and (2) individual SPDES permits for storm water discharges. The Department considered removing the two year re-evaluation period for impacts to Principal Aquifers.

No High-Volume Hydraulic Fracturing Operations within 2,000 feet of Public Drinking Water Supplies

More than 360,000 people (or roughly 40.9% of the population) in the Marcellus Shale play area are served by individual private wells or public surface water supplies, or community supplies outside of Primary and Principal Aquifer areas. The SGEIS seeks to reduce the risk of significant adverse impacts on water resources from potential surface discharges from high-volume hydraulic fracturing well pads by proposing that high-volume hydraulic fracturing well pads at any surface location within 2,000 feet of public water supply wells, river or stream intakes and reservoirs should not be permitted. In an attempt to further reduce the potential risks, the Department additionally considered requiring a 2,000-foot prohibition around a public (municipal or otherwise) drinking water supply intake in flowing water with an additional prohibition of 1,000 feet on each side of the main flowing waterbody and any tributary to that waterbody, both for a distance of 1 mile upstream from the public drinking water supply intake.

No High-Volume Hydraulic Fracturing Operations in Floodplains or Within 500 Feet of Private Water Wells

In order to address potential significant adverse impacts due to flooding, the SGEIS evaluated the significant impacts associated with high-volume hydraulic fracturing development located wholly or partially within a 100-year floodplain. In further recognition of the increasing frequency and intensity of recent and potentially future flood events, the Department considered requiring that, in certain areas, well pads be elevated two feet above the 500-year floodplain elevation or the known elevation of the flood of record. However, the Department notes that flood risks change over time and consequently potential impacts could still occur from high-volume hydraulic fracturing as a result of incomplete data.

Since just 2000, 16,000 new private water wells in the Marcellus Shale play area have been reported to the Department; this averages out to over 1,000 per year. In order to reduce potential impacts on drinking water supplies from high-volume hydraulic fracturing operations, the SGEIS evaluated impacts on private water wells and domestic use springs and considered prohibiting any well pad located within 500 feet of a private water well or domestic supply spring, unless the Department issued a variance from the requirement, with the consent of the landowner, and any tenants, if applicable. The final SGEIS reflects the importance of protecting this resource so critical to residents within the Marcellus Shall play area.

Mandatory Disclosure of Hydraulic Fracturing Additives and Alternatives Analysis

The SGEIS identifies by chemical name and Chemical Abstract Services (CAS) number 322 chemicals proposed for use for high-volume hydraulic fracturing in New York. Chemical usage was reviewed by NYSDOH, which provided health hazard information that is presented in the document. In response to public concerns relating to the use of hydraulic fracturing additives and their potential impact on water resources, this SGEIS contains a requirement that operators evaluate and use alternative hydraulic fracturing additive products that pose less potential risk to water resources if high-volume hydraulic fracturing were authorized. In addition, in the EAF addendum a project sponsor must disclose all additive products it proposes to use, and provide Material Safety Data Sheets for those products, so that the appropriate remedial measures could be employed if a spill were to occur. If high-volume hydraulic fracturing were authorized, the Department would publicly disclose the identities of hydraulic fracturing fluid additive products and their Material Safety Data Sheets, provided that information which meets the confidential business information exception to the Department's records access program will not be subject to public disclosure. In addition, the Department considered expanding the fracturing fluid chemical disclosure requirements to ensure that each chemical, and not merely each product, would be disclosed both before drilling and after completion of each well.

Enhanced Well Casing

In order to mitigate the risk of significant adverse impacts to water resources from the migration of gas or pollutants in connection with high-volume hydraulic fracturing operations, the SGEIS added a requirement for a third cemented "string" of well casing around the gas production wells in most situations. This enhanced casing specification is designed to specifically reduce potential impacts from migration of gas into aquifers.

Required Secondary Containment and Stormwater Controls

The risk of a significant adverse impact to water resources from spills of chemical additives, hydraulic fracturing fluid or liquid wastes associated with high-volume hydraulic fracturing, secondary containment, spill prevention and storm water pollution prevention have been evaluated in the SGEIS. However, because of the unique aspects of multi-well pad development associated with high-volume hydraulic fracturing, the existing Department engineering controls and management practices that would be required are untested for the scale of this activity and, consequently, it remains uncertain whether they would be adequate to prevent spills and mitigate adverse impacts if a spill occurs. Compounding this risk is the current uncertainty, as identified by NYSDOH, regarding the level of risk high-volume hydraulic fracturing activities pose to public health.

Conditions Related to Disposal of Wastewater and Solid Waste

The Department had proposed to require that before any permit is issued the well operator have Department-approved plans in place for disposing of flowback water and production brine. In addition, the Department proposed to require a tracking system, similar to what is in place for medical waste, for all liquid and solid wastes generated in connection with high-volume hydraulic fracturing operations.

The SGEIS also contains a requirement for closed-loop drilling to address impacts related to the disposal of pyrite-rich Marcellus Shale cuttings on-site.

Air Quality Control Measures and Mitigation for Greenhouse Gas Emissions

The SGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations would not result in the exceedance of any NAAQS if high-volume hydraulic fracturing were authorized. In addition, the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas.

The SGEIS also identifies mitigation measures that could be required through permit conditions and possibly new regulations to reduce GHG emissions from high-volume hydraulic fracturing activities. The SGEIS would require a GHG emission impacts mitigation plan (the Plan). The Plan would include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of the U.S. Environmental Protection Agency's (EPA) Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the requirements of the EPA GHG Reporting Program (40 CFR §98), which mandates the monitoring and reporting of GHG emissions from certain source categories in the United States.

Mitigation for Loss of Habitat and Impacts on Wildlife

The Department had proposed several mitigation measures to attempt to address the significant adverse impacts on wildlife habitat caused by fragmentation of forest and grasslands on private land. Although a site-specific environmental assessment and SEQRA determination of significance may have assisted the Department in reducing such impacts, the cumulative nature of the impacts across the area where high-volume hydraulic fracturing would likely occur is such that the impacts would remain only partially mitigated.

Chapter 8 – Permit Process and Regulatory Coordination

This Chapter explains inter- and intra-agency coordination relative to the well permit process, including the role of local governments and a revised approach to local government notification and consideration of potential impacts of high-volume hydraulic fracturing operations on local land use laws and policies. The Department also considered requiring that every ECL Article 23 well application proposing high-volume hydraulic fracturing on a new well pad be subject to a fifteen-day public notice period, limited to site-specific issues on the subject application not addressed in the 1992 GEIS or this SGEIS. As a result of the *Matter of Wallach v. Town of Dryden and Cooperstown Holstein Corp. v. Town of Middlefield* decision, some towns could exercise their zoning authority in such a way that they would be involved agencies under SEQRA. This means that the Department would be required to coordinate the environmental review with such government agencies if the permit required discretionary approvals from a local government agency (e.g., a special use permit or some other type of zoning approval).

Chapter 9 – Alternative Actions

Chapter 9 discusses the alternatives to well permit issuance that were reviewed and considered by the Department. The SGEIS considers a range of alternatives for authorizing high-volume hydraulic fracturing operations in New York. As required by SEQRA, the SGEIS considers the No Action Alternative. The No Action Alternative would not result in any of the significant adverse impacts identified herein, but would also not result in any of the potential economic and other benefits identified with natural gas drilling by this method.

The alternatives analysis also considers 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 SGEIS also contains a review and analysis of the development and use of “green” or non-chemical fracturing alternatives. The use of environmentally friendly or “green chemicals” would depend on both their reduced toxicity and their technical effectiveness in the Marcellus Shale play and other shale plays. While more research and approval criteria would be necessary to establish benchmarks for “green chemicals,” this Final SGEIS proposes that if high-volume hydraulic fracturing were authorized, this alternative approach be adopted by requiring applicants to review and consider, to the Department’s satisfaction, the use of alternative additive products that may pose less risk to the environment, including water resources, where feasible, and to publicly disclose the chemicals that make up these additives. These requirements would be altered and/or expanded as the use of “green chemicals” begins to provide reasonable alternatives and the appropriate technology, criteria and processes are put in place to evaluate and produce “green chemicals.”

Chapter 10 – Review of Selected Non-Routine Incidents in Pennsylvania

Chapter 10 discusses a number of incidents involving high-volume hydraulic fracturing operations in Pennsylvania that have caused concern about the safety and potential adverse impacts associated with high-volume hydraulic fracturing operations.

Chapter 11 – Summary of Potential Impacts and Mitigation Measures

Chapter 11 highlights the mitigation measures implemented through the 1992 GEIS and summarizes the impacts and mitigation that are discussed in Chapters 6 and 7.

Response to Comments

The accompanying Response to Comments includes summaries of the substantive comments received on both the 2009 dSGEIS and the 2011 rdSGEIS, along with the Department's responses to such comments.

NEW YORK
STATE OF
OPPORTUNITY.

Department of
Environmental
Conservation

Chapter 1

Introduction

Final

Supplemental Generic Environmental Impact Statement

Chapter 1 – Introduction

Chapter 1 INTRODUCTION

The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production. To release the gas embedded in the shale formations, wells would undergo a stimulation process known as high-volume hydraulic fracturing. While the horizontal well applications received to date are for proposed locations in Broome, Cattaraugus, 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 in Otsego and Schoharie Counties and elsewhere as shown in Chapter 4. Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing. The Department has prepared this revised draft Supplemental Generic Environmental Impact Statement (SGEIS) to satisfy the requirements of the State Environmental Quality Review Act (SEQRA) for some of these anticipated operations. In reviewing and processing permit applications for horizontal drilling and hydraulic fracturing in these deep, low-permeability formations, the Department would apply the findings and requirements of the SGEIS, including criteria and conditions for future approvals, in conjunction with the existing Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, issued by the Department in 1992 (1992 GEIS).[1]

1.1 Hydraulic Fracturing and Multi-Well Pad Drilling

Hydraulic fracturing is a well stimulation technique which consists of pumping an engineered fluid system and a propping agent (proppant) such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. The fractures serve as pathways for hydrocarbons to move to the wellbore for production. Further information on high-volume hydraulic fracturing, including the composition of the fluid system, is provided in Chapter 5.

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[1] The 1992 GEIS is posted on the Department's website at http://www.dec.ny.gov/energy/45912.html.

For environmental review purposes pursuant to SEQRA, stimulation including hydraulic fracturing is considered part of the action of drilling a well. Wells where high-volume hydraulic fracturing is used may be drilled vertically, directionally or horizontally. Multiple wells may be drilled from a common location (multi-well pad or multi-well site).

1.1.1 Significant Changes in Proposed Operations Since 2009

The gas drilling industry has informed the Department of the following changes in its planned operations in New York, based, in part, on experience gained in actively developing the Marcellus Shale in Pennsylvania. These changes are reflected in the assumptions used in this revised draft SGEIS to identify and consider potential significant adverse impacts.

1.1.1.1 Use of Reserve Pits or Centralized Impoundments for Flowback Water

The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments.[2] Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review.

1.1.1.2 Flowback Water Recycling

The Department was also informed in September 2010 that operators plan to maximize reuse of flowback water for subsequent high-volume hydraulic fracturing operations, with some companies targeting goals of recycling 100% of flowback water.[3] The technologies for accomplishing this have evolved through ongoing Marcellus Shale development in Pennsylvania. The Susquehanna River Basin Commission (SRBC) has confirmed that operators are re-using flowback water.[4] This development has the potential to greatly reduce the volume of flowback water that requires treatment, hauling and disposal, and the related environmental concerns. Fresh water consumption and hauling are also somewhat reduced, but in current practice fresh water still comprises 80-90% of the water used at each well for high-volume hydraulic fracturing.

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[2] ALL Consulting, 2010, pp. 18-19.

[3] ALL Consulting, 2010, pp. 73-76.

[4] Richenderfer, 2010, p. 30.

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 . . . ,"[5] 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 (ECL 23) 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.[6]

1.3 State Environmental Quality Review Act

As explained in greater detail in Chapter 3, the Department's SEQRA regulations authorize the use of generic environmental impact statements to assess the environmental impacts of separate actions having generic or common impacts. Drilling and production of separate oil and gas wells, and other wells regulated under the Oil, Gas and Solution Mining Law (ECL 23) 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 finalized a Generic Environmental Impact Statement and issued SEQRA Findings on the regulatory program in 1992 (1992 GEIS). In 2008, the Department determined that some aspects of the current and anticipated application of high-volume hydraulic fracturing, which is often used in conjunction with horizontal drilling and multi-well pad development, warranted further review in the context of a SGEIS. This revised draft SGEIS discusses high-volume hydraulic fracturing in great detail

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

[6] 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.

and describes the potential significant impacts from this activity as well as measures that would fully or partially mitigate the identified impacts. Specific mitigation measures would be adopted as part of the Department's Findings Statement in the event high-volume hydraulic fracturing is authorized pursuant to the studies presented herein.

1.4 Project Chronology

1.4.1 February 2009 Final Scope

The Department released a draft Scope for public review in October 2008, and held public scoping sessions at six venues in the Southern Tier and Catskills in November and December, 2008. 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 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.

1.4.2 2009 Draft SGEIS

The Department released the 2009 draft SGEIS for public review on September 30, 2009 and held public hearings at four venues in New York City (NYC), the Catskills and the Southern Tier in October and November, 2009. Comments were accepted at the hearings verbally and in writing, by postal mail, by e-mail and through a web-based application developed specifically for that purpose. More than 2,500 people attended the Department hearings, and more than 200 verbal comments were delivered by individuals, local government officials, representatives of environmental groups and other organizations and members of the oil and gas industry. The Department also received over 13,000 comments via e-mail, postal mail and the web-based comment system. In addition, transcripts from hearings held by the New York State Assembly, the City of Oneonta, and the Tompkins County Council of Governments on the 2009 draft SGEIS also provided the Department with numerous comments.

1.4.2.1 April 2010 Announcement Regarding Communities with Filtration Avoidance Determinations

On April 23, 2010, then-Commissioner Pete Grannis announced that due to the unique issues related to the protection of NYC and Syracuse drinking water supplies, these watersheds would be excluded from the generic environmental review process.

1.4.2.2 Subsequent Exclusion of Communities with Filtration Avoidance Determinations

The analysis of high-volume hydraulic fracturing conducted since the 2009 draft SGEIS supports a finding that high-volume hydraulic fracturing is not consistent with the preservation of these watersheds as an unfiltered drinking water supply.

1.4.3 2011 Revised Draft SGEIS

On January 1, 2011, Governor Cuomo continued Executive Order No. 41 (EO 41), which had been issued by then-Governor Paterson on December 13, 2010. EO 41 directed the Department to publish a revised draft SGEIS on or about June 1, 2011 and to accept public comment on the revisions for a period of not less than 30 days.

On July 1, 2011, the Department published the Executive Summary of the Preliminary Revised Draft SGEIS, prepared after considering the many comments received on the Draft SGEIS, and on July 8, 2011, the Department published the full Preliminary Revised Draft SGEIS.

On September 7, 2011, the Department published a full Revised Draft SGEIS with a supporting socioeconomic study for public comment. Hearings were held in four locations throughout the state in November 2011. Approximately 67,000 comments were received by the close of the comment period on January 11, 2012.

1.4.4 Draft Regulations

At the same time that the revised draft SGEIS was released in September 2011, the Department published draft regulations for comment. In December 2012, DEC published revised draft HVHF regulations. Over 180,000 comments were received on the proposed regulations. These proposed regulations have lapsed under State law.

1.4.5 Health Review by the New York State Department of Health

In September 2012, DEC Commissioner Martens requested the New York State Health Commissioner to assess the health impact analysis in DEC's revised draft SGEIS. The New York State Department of Health (NYSDOH) retained three national experts, Drs. Lynn Goldman (G. Wash. School of Pub. Health), John Adgate (Col. School of Pub. Health) and Richard Jackson (UCLA School of Pub. Health), to assist in the review of the SGEIS. NYSDOH also reviewed and evaluated scientific literature, engaged in field visits and discussions with health and environmental authorities in nearly all states where HVHF activity is taking place, and communicated with local, state, federal, international, academic, environmental and public health stakeholders.

On December 17, 2014, Acting NYSDOH Commissioner Dr. Howard Zucker announced that NYSDOH had completed its public health review of HVHF and recommended that HVHF should not move forward in New York State. NYSDOH issued a report entitled "A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development."[7] (See Appendix A to the accompanying Response to Comments.)

1.4.6 Final SGEIS

By publishing this SGEIS and the accompanying Response to Comments, the Department is further implementing EO 41.

1.4.7 Next Steps

At least 10 days after filing of the final SGEIS, the Department will issue a written Findings Statement. Chapter 3 presents detailed information about a proposed future SEQRA compliance process.

1.5 Methodology

1.5.1 Information about the Proposed Operations

For the 2009 draft SGEIS, the Department primarily relied on two sources of information regarding the operations proposed for New York: (1) a number of permit applications filed with the Department; and (2) the Independent Oil & Gas Association of New York (IOGA-NY),

[7] The report can also be found at: http://www.health.ny.gov/press/reports/docs/high_volume_hydraulic_fracturing.pdf.

which provided the Department with information from operators actively developing the Marcellus Shale in Pennsylvania.

Preliminary review of comments on the 2009 draft SGEIS led Department staff to identify additional technical and operational details needed from industry in order to evaluate and address the comments. In April 2010, Department staff sent a "Notice of Information Needs" to IOGA-NY and to specific exploration/production and service companies that commented on the 2009 draft SGEIS. Again, IOGA-NY coordinated industry's response, which was received in September 2010 (ALL Consulting, 2010).

Department staff also communicated with and reviewed information and data made available from the Pennsylvania Department of Environmental Protection (PADEP) and the SRBC about events, regulations, enforcement and other matters associated with ongoing Marcellus Shale development in Pennsylvania.

1.5.2 Intra-/Inter-agency Coordination

Within the Department, preparation of both the 2009 draft SGEIS and the revised draft SGEIS involved all of the programs listed on the "Acknowledgements" page of each document.[8] Other State agencies also provided assistance. Department staff consulted extensively with NYSDOH staff, and staff in the Department of Public Service (Public Service Commission, or PSC) assisted with the text describing that Department's jurisdiction and regulation over gas gathering facilities.

1.5.3 Comment Review

Of the nearly 13,300 comments received on the 2009 draft SGEIS, at least 9,830 were identified as various campaigns likely generated by on-line form letters, eleven were unique petitions signed by 31,464 individuals and organizations collectively, and seven were the transcripts of the hearings described in Subsection 1.4.2. Each of the transcripts includes comments from a large number of speakers, some of whom also submitted written comments. These transcripts were treated as official public comments, and all comments received were given equal consideration

[8] As a result of organizational changes within the Department, the Division of Solid & Hazardous Materials is now the Division of Materials Management.

regardless of the method by which they are received. Department staff read and categorized every transcript and every piece of correspondence received to ensure that all substantive comments would be evaluated.

Although the comment period on the 2009 draft SGEIS officially closed on December 31, 2009, the Department accepted all comments submitted through January 8, 2010 to further ensure that all substantive comments would be considered. As noted above, approximately 67,000 comments were received by the close of the comment period for the revised draft SGEIS on January 11, 2012. Following this comment period, Department staff again reviewed and categorized every comment. Comments on both draft documents were consolidated, and all programs involved in preparing the revised draft SGEIS also participated in developing responses to the summarized comments. The accompanying Response to Comments (Vol. 2) includes summaries of the substantive comments received on both the 2009 draft SGEIS and the revised dSGEIS, along with the Department's responses to such comments.

1.6 Layout and Organization

The revised draft SGEIS supplements the existing 1992 GEIS, and does not exhaustively repeat narrative from the 1992 GEIS that remains applicable to well permit issuance for horizontal drilling and high-volume hydraulic fracturing.

1.6.1 Chapters

Chapter 1 is an introduction that explains the context, history and contents of the document, and highlights the enhanced procedures, regulations and mitigation measures incorporated into the document.

Chapter 2 is a description of the proposed action, and includes sections on purpose, public need and benefit, project location and environmental setting that are required by SEQRA. The environmental setting section focuses on topics that arose during the public scoping sessions. For a comprehensive understanding of the environmental setting where high-volume hydraulic fracturing might occur, it is necessary to also consult the 1992 GEIS.

Chapter 3 describes the use of a generic environmental impact statement and the resultant SEQRA review process, identifies those potential projects which would require site-specific

SEQRA determinations of significance after the SGEIS is completed, and identifies restricted locations where high-volume hydraulic fracturing would be prohibited.

Chapter 4 supplements the geology discussion in Chapter 5 of the 1992 GEIS with additional details about the Marcellus and Utica Shales, seismicity in New York State, naturally-occurring radioactive materials (NORM) in the Marcellus Shale and naturally-occurring methane in New York State.

Chapter 5 comprehensively describes the activities associated with high-volume hydraulic fracturing and multi-well pad drilling, including the composition of hydraulic fracturing additives and flowback water characteristics.

Chapter 6 describes potential impacts associated with the proposed activity and, like other chapters, should be read as a supplement to the 1992 GEIS.

Chapter 7 describes the enhanced procedures, regulations and proposed mitigation measures that have been identified to fully and/or partially mitigate potential significant adverse impacts from high-volume hydraulic fracturing activities to be covered by the SGEIS and 1992 GEIS for SEQRA purposes.

Chapter 8 explains intra- and interagency coordination involved in the well permitting process, including the role of local governments and an expanded approach to local government notification. Descriptions of other regulatory programs that govern some aspects of the potential activities that were previously distributed among several chapters in the document are also now included in Chapter 8.

Chapter 9 discusses the alternatives to well permit issuance that were reviewed and considered.

Chapter 10 is new in the revised draft SGEIS and provides information on certain non-routine incidents in Pennsylvania where development of the Marcellus Shale by high-volume hydraulic fracturing is currently ongoing.

Chapter 11 is new in the revised draft SGEIS and summarizes the impacts and mitigation discussed in Chapters 6 and 7.

The Department's response to comments (Vol. 2) represents the Department's most current assessment of the impacts associated with high-volume hydraulic fracturing and the effectiveness of proposed or considered mitigation measures to adequately mitigate significant adverse environmental and public health impacts. To the extent that there is any inconsistency between the Response to Comments and the text within the chapters and appendices of this Final SGEIS, the Response to Comments should be relied upon.

1.6.2 Revisions

Revisions to the 2011 revised draft SGEIS text are generally marked by vertical lines in the page margins, and new text is underlined.

1.6.3 Glossary, Bibliographies and Appendices

The Chapters described above are augmented by 27 Appendices and a lengthy glossary that includes acronyms and technical or scientific terms that appear in the document. References cited throughout the document are listed in a bibliography, and separate bibliographies are included that list the various consultants' sources.

1.7 Enhanced Impact Analyses and Mitigation Measures

The Department has identified numerous enhanced procedures and proposed mitigation measures that are available to address the potential significant environmental impacts associated with well permit issuance for horizontal drilling and high-volume hydraulic fracturing. Only the most significant are listed below. Chapter 7 of this document and the 1992 GEIS in its entirety would need to be consulted for the full range of available and required mitigation practices.

The list presented below does not include analyses and mitigation measures proposed in September 2009 that are superseded by the revised draft SGEIS, or that are no longer relevant because of changes in proposed operations.

1.7.1 Hydraulic Fracturing Chemical Disclosure

The Department's hydraulic fracturing chemical disclosure requirements and public disclosure approach set forth in Chapter 8, combined with the chemical disclosures required from industry for the SGEIS analysis, make the Department's disclosure regime among the most stringent in the country. The Department's regime exceeds the requirements of 22 of the 27 oil and gas producing states reviewed and is on par with the five states currently leading the country on chemical disclosure. Additionally, the enhanced disclosure requirements are equivalent to the proposed requirements of the federal Fracturing Awareness and Responsibility (FRAC) Act of 2011.

1.7.2 Water Well Testing

Prior to drilling, operators would be required to test private wells within 1,000 feet of the drill site to provide baseline information and allow for ongoing monitoring. If there are no wells within 1,000 feet, the survey area would extend to 2,000 feet. Chapter 7 reflects updated recommendations from the NYSDOH regarding what analyses should be conducted.

1.7.3 Water Withdrawal and Consumption

1.7.3.1 2009 Draft SGEIS

Applicants would not only have to follow SRBC and Delaware River Basin Commission (DRBC) protocols for water withdrawal where applicable, but would also be required to adhere to a more stringent and protective passby flow requirement in regards to water withdrawal plans - whether inside or outside of the Susquehanna or Delaware river basins. The intended results of these requirements would be to protect aquatic organisms and their habitats in surface waters.

1.7.3.2 Revised Draft SGEIS

The discussion of passby flow and the required streamflow analysis have been updated based on research and studies conducted after the release of the 2009 draft SGEIS. Additionally, details have been added regarding the Department's methodology for evaluating and determining approvable groundwater withdrawal rates.

1.7.4 Well Control and Emergency Response Planning

Although current practices and requirements have proven effective at countless wells throughout New York State, the Department has responded to the public's heightened concerns regarding well control and emergency response issues by including three significant revisions in the revised draft SGEIS:

- Submission, for review in the permit application, of the operator's proposed blowout preventer use and test plan for drilling and completion;

- Description of the required elements of an emergency response plan (ERP); and
- Submission and on-site availability of an ERP consistent with the SGEIS, including a list of emergency contact numbers for the community surrounding the well pad.

1.7.5 Local Planning Documents

The Department proposes that applicants be required to compare the proposed well pad location to local land use laws, regulations, plans and policies to determine whether the proposed activity is consistent with such local land use laws, regulations, plans and policies. If the applicant or the potentially impacted local government informs the Department that it believes a conflict exists, the Department would request additional information with regard to this issue so it can consider whether significant adverse impacts relating to land use and zoning would result from permit issuance.

1.7.6 Secondary Containment, Spill Prevention and Stormwater Pollution Prevention

The Department proposes to require, via permit condition and/or new regulation, that operators provide secondary containment around all additive staging areas and fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans. In addition, drilling and hydraulic fracturing operations would be subject to an activity-specific general stormwater permit that would address industrial activities as well as the construction activities that are traditionally the focus of stormwater permitting for oil and gas well sites. The comprehensive Stormwater Pollution Prevention Plan (SWPPP) would incorporate by reference a Spill Prevention, Control and Countermeasures Plan.

1.7.7 Well Construction

Existing requirements are designed to ensure that surface casing be set deeply enough to not only isolate fresh water zones but also to serve as an adequate foundation for well control while drilling deeper. It is also necessary under existing requirements, to the extent possible, to avoid extending the surface casing into shallow gas-bearing zones. Existing casing and cementing requirements that are incorporated into permit conditions establish the required surface casing setting depth based on the best available site-specific information. Each subsequent installation of casing and cement serves to further protect the surface casing and hence, the surrounding fresh water zones.

1.7.7.1 2009 Draft SGEIS

Proposed well construction enhancements for high-volume hydraulic fracturing included:

- Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and

- Required certification prior to hydraulic fracturing of the sufficiency of as-built wellbore construction.

1.7.7.2 Revised Draft SGEIS

Additional well construction enhancements for high-volume hydraulic fracturing that the Department proposes to require pursuant to permit condition and/or regulation are listed below:

- Specific American Petroleum Institute (API) standards, specifications and practices would be incorporated into permit conditions related to well construction. Among these would be requirements to adhere to specifications for centralizer type and for casing and cement quality;

- Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones;

- Additional measures to ensure cement strength and sufficiency would be incorporated into permit conditions, also directly addressing gas migration concerns. Compliance would continue to be tracked through site inspections and required well completion reports, and any other documentation the Department deems necessary for the operator to submit or make available for review; and

- Minimum compressive strength requirements.

    - Minimum waiting times during which no activity is allowed which might disturb the cement while it sets;

    - Enhanced requirements for use of centralizers which serve to ensure the uniformity and strength of the cement around the well casing; and

    - Required use of more advanced cement evaluation tools.

1.7.8 Flowback Water Handling On-Site

The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.

1.7.9 Flowback Water Disposal

Under existing regulations, before a permit is issued, the operator must disclose plans for disposal of flowback water and production brine. Further, in the SGEIS the Department proposes to use a new "Drilling and Production Waste Tracking" process, similar to the process applicable to medical waste, to monitor disposal. Under existing regulations, full analysis and approvals under state water laws and regulations are required before a water treatment facility can accept flowback from high-volume hydraulic fracturing operations. Appendix 22 includes a description and flow chart of the required approval process for discharge of flowback water or production brine from high-volume hydraulic fracturing to a Publicly-Owned Treatment Works (POTW). An applicant proposing discharge to a POTW would be required to submit a treatment capacity analysis for the receiving POTW, and, in the event that the POTW is the primary fluid disposal plan, a contingency plan. Additionally, limits would be established for NORM in POTW influent.

1.7.10 Management of Drill Cuttings

The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore, the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site, at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills. The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:

- Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and

- Cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.

Only ARD mitigation plans that do not require long-term monitoring would be acceptable. Examples are provided in Chapter 7.

1.7.11 Emissions and Air Quality

The need to re-evaluate air quality impacts and the applicability of various regulations was raised during the scoping process, with emphasis on the duration of activities at a multi-well pad and the number of internal combustion engines used for high-volume hydraulic fracturing.

1.7.11.1 2009 Draft SGEIS

The following conclusions and requirements were set forth:

- Per United States Environmental Protection Agency (EPA) NESHAPS subpart ZZZZ, the compressor station would have an oxidation catalyst for formaldehyde. This also reduces carbon monoxide (CO) by 90% and Volatile Organic Compounds (VOCs) by 70%;
- Per EPA subpart HH, the glycol dehydrator would have a condenser to achieve a benzene emission of <1 ton per year (Tpy) (if "wet" gas is detected);
- Use of Ultra Low Sulfur Fuel (ULSF) of 15 parts per million (ppm) in all engines would be required;
- Small stack height increases on compressor, vent and dehydrator would be required (if "sour" and "wet" gas encountered for the latter two, respectively);
- All annual and short-term ambient standards (National Ambient Air Quality Standards, or NAAQS) and the Department's toxics thresholds (Annual and Short-Term Guideline Concentrations, or AGCs and SGCs) would be met, except 24-hour PM10/PM2.5 NAAQS due to drilling and hydraulic fracturing engines; and
- Impacts from a nearby pad modeled and indicated no overlap in the calculated "cumulative" impacts on local scale.

The facility definition for permitting was based on Clean Air Act (CAA) 112(n)(4) per EPA guidance at the time, which limits it to "surface area" (i.e., per pad). Annual emissions from all sources were calculated assuming ten wells per pad and resulted in a classification of the emissions as "minor" sources. No final determination was made as to whether non-road engines would be part of "stationary" facility since it was unclear before September 2009 if these would be at the pad more than 12 months.

1.7.11.2 Revised Draft SGEIS

The Department performed substantive additional emissions and air quality analyses, which identified the following mitigation measures that the Department proposes to require through enhanced procedures, permit conditions and/or regulations:

- The diesel fuel used in drilling and completion equipment engines would be limited to ULSF with a maximum sulfur content of 15 ppm;
- There would not be any simultaneous operations of the drilling and completion equipment engines at the single well pad;
- The maximum number of wells to be drilled and completed annually or during any consecutive 12-month period at a single pad would be limited to four;
- The emissions of benzene at any glycol dehydrator to be used at the well pad would be limited to 1 Tpy as determined by calculations with the Gas Research Institute's (GRI) GlyCalc program. If wet gas is encountered, then the dehydrator would have a minimum stack height of 30 feet (9.1 meters) and would be equipped with a control device to limit the benzene emissions to 1 Tpy;
- Condensate tanks used at the well pad would be equipped with vapor recovery systems to minimize fugitive VOC emissions;
- During the flowback phase, the venting of gas from each well pad would be limited to a maximum of 5 million standard cubic feet (MMscf) during any consecutive 12 month period. If "sour" gas is encountered with detected hydrogen sulfide (H2S) emissions, the height at which the gas would be vented would be a minimum of 30 feet (9.1 meters);
- During the flowback phase, flaring of gas at each well pad would be limited to a maximum of 120 MMscf during any consecutive 12-month period;
- Wellhead compressors would be equipped with Non-Selective Catalytic Reduction (NSCR) controls;
- No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines would be used for any activity at the well sites;
- The drilling engines and drilling air compressors would be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these would be equipped with both particulate traps (Continuously Regenerating Diesel Particulate Filters, or

CRDPF) and Selective Catalytic Reduction (SCR) controls. During operations, this equipment would be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site-specific information would be provided to the Department for review and concurrence; and

- The completion equipment engines would be limited to EPA Tier 2 or newer equipment. CRDPFs would be required for all Tier 2 engines. SCR control would be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment would be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information would be provided to the Department for review and concurrence.

In addition, the revised draft SGEIS discusses the effect of region-wide emissions on State Implementation Plan (SIP) for Ozone NAAQS and implementation of local and regional level air quality monitoring at well pads and surrounding areas.

1.7.12 Greenhouse Gas Mitigation

All operational phases of well pad activities, and all greenhouse gas (GHG) emission sources are evaluated in both the 2009 draft SGEIS and the current draft. Based on this analysis, the Department proposes in the current draft to require the following controls and mitigation measures, pursuant to permit conditions and/or regulation:

- Implementation by the operator of a Leak Detection and Repair Program;
- Upon request, the operator would be required to provide a copy of data required under federal (EPA) GHG reporting rule;
- Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition, two years after issuance of the first permit for high-volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited; and
- Implementation of other control technologies when applicable, as described in Chapter 7.

1.7.13 Habitat Fragmentation

The current draft includes a substantially augmented analysis of potential impacts from high-volume hydraulic fracturing on wildlife and habitat. Based on that analysis, two measures that were not included in the 2009 draft SGEIS are proposed as mitigation in the revised draft SGEIS:

- *Grassland Focus Areas on private land* – Surface disturbance in grassland patches comprised of 30 acres or more of contiguous grassland within Grassland Focus Areas would be contingent on the findings of a site-specific ecological assessment conducted by the permit applicant and implementation of mitigation measures identified as part of such ecological assessment; and

- Forest Focus Areas on private land – Surface disturbance in forest patches comprised of 150 acres or more of undisturbed, contiguous forest within Forest Focus Areas would be contingent on a site-specific ecological assessment conducted by the permit applicant and implementation of mitigation measures identified as part of such ecological assessment.

1.7.14 State Forests, State Wildlife Management Areas and State Parks

Surface disturbance associated with high-volume hydraulic fracturing would not be allowed on State-owned lands administered by the Department, including but not limited to State Forests and State Wildlife Management Areas, because it is inconsistent with the suite of purposes for which those lands have been acquired. Current Office of Parks, Recreation and Historic Preservation (OPRHP) policy would impose a similar restriction on State Parks.

1.7.15 Community and Socioeconomic Impacts

Chapter 6 of this revised draft SGEIS includes a significantly expanded discussion of community and socioeconomic impacts, traffic impacts, and noise and visual impacts, with measures that will be implemented by the Department to mitigate these impacts described in Chapter 7.

1.8 Additional Precautionary Measures

In order to safeguard the environment from risks associated with spills or other events that could release contaminants into environmentally sensitive areas, the revised draft SGEIS includes the following prohibitions and mitigation measures for high-volume hydraulic fracturing:

- Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds;

- Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing);

- Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing);

- For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary;

- The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains; and

- The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, unless waived by the owner.

As reflected in the response to comments, subsequent to the issuance of the 2011 dSGEIS and in the face of ever-increasing information and scientific studies detailing the risks and uncertainties regarding the environmental and public health impacts that result from HVHF development, the Department considered numerous additional mitigation measures to protect and reduce impacts to drinking and other water resources, air, and other resources, including, for example, banning any HVHF development in the Catskill Park, extending setbacks from various resources and eliminating sunset periods for various restrictions.

NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Chapter 2

Description of Proposed Action

Final

Supplemental Generic Environmental Impact Statement

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Chapter 2 – Description of Proposed Action

FIGURES

TABLES

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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. Wells where high-volume hydraulic fracturing is used may be drilled vertically, directionally or horizontally. The proposed action, however, does not include horizontal drilling where high-volume hydraulic fracturing is not employed. Such drilling is covered under the GEIS.

Hydraulic fracturing is a well stimulation technique which consists of pumping an engineered fluid system and a proppant such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. The fractures serve as pathways for hydrocarbons to move to the wellbore for production. High-volume hydraulic fracturing, using 300,000 gallons of water or more per well, is also referred to as "slick water fracturing." An individual well treatment may consist of multiple stages (multi-stage fracturing). Further information on high-volume hydraulic fracturing, including the composition of the fluid system, is provided in Chapter 5.

Multiple wells may be drilled from a common location (multi-well pad, or multi-well site). The Department may receive applications to drill approximately 1,700 – 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a "peak development" year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period.[9] More information about these activity estimates and the factors which could affect them is presented in Chapter 5.

This SGEIS is focused on topics not addressed by the 1992 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. An additional aspect of this SGEIS is to consider measures that will be incorporated into revisions or additions to the Department's regulations concerning high-volume hydraulic fracturing.

[9] ALL Consulting, 2010, pp. 7 - 9.

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 1992 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. The SGEIS will also be used to satisfy SEQR for the enactment of revisions or additions to the Department's regulations relating to high-volume hydraulic fracturing.

2.2 Project Location

The 1992 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. Drilling will not occur on State reforestation areas and wildlife management areas that are located in the Forest Preserve because the State Constitution prohibits those areas from being leased or sold. Surface disturbance associated with high-volume hydraulic fracturing would not be allowed on State-owned lands administered by DEC outside of the Forest Preserve, including but not limited to State Forests and State Wildlife Management Areas, because high-volume hydraulic fracturing would be inconsistent with the purposes for which those lands were acquired. Current OPRHP policy would impose a similar restriction on State Parks. In addition, the subsurface geology of the Adirondacks, NYC and Long Island and other factors render 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.

2.3 Environmental Setting

Environmental resources discussed in the 1992 GEIS with respect to potential impacts from oil and gas development include: waterways/water bodies; drinking water supplies; public lands; coastal areas; wetlands; floodplains; soils; agricultural lands; intensive timber production areas; significant habitats; areas of historical, architectural, archeological and cultural significance; clean air and visual resources.[10] 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.

2.3.1 Water Use Classifications[11]

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 NYCRR Part 701.

In general, the discharge of sewage, industrial waste, or other wastes must 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, the Department 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.

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[10] NYSDEC, 1992, 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.

[11] URS, 2009, p. 4-2.

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; and

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; and

f. Class GSB waters are saline groundwaters that have a chloride concentration in excess of 1,000 milligrams per liter (mg/L) or a total dissolved solids (TDS) concentration in excess of 2,000 mg/L; this classification shall not be assigned to any groundwaters of the State, unless the Department 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 2.1 above]

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 the Department 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; and

3. Per 6 NYCRR §701.24, specified substances shall not be permitted in new discharges, and no increase in the release of specified substances 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.

2.3.2 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 the Department. The NYC Department of Environmental Protection (NYCDEP) defers to the New York State Department of Health (NYSDOH) for water classifications and quality standards. The most recent NYC Drinking Water Quality Report can be found at http://www.nyc.gov/html/dep/pdf/wsstate10.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 (DRBC) has established independent classifications and water quality standards throughout the Delaware River Basin, including those portions within New York. The relevant and applicable water quality standards and classifications include the following:

- 6 NYCRR Part 703, Surface Water and Groundwater Quality Standards and Groundwater Effluent Limitations;[12]
- USEPA Drinking Water Contaminants;[13]
- 18 CFR Part 410, DRBC Administrative Manual Part III Water Quality Regulations;[14]

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

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

- 10 NYCRR Part 5, Subpart 5-1 Public Water Systems; [15] and
- NYCDEP Drinking Water Supply and Quality Report.[16]

2.3.3 Drinking Water[17]

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.

2.3.3.1 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 has elected to enforce both as Maximum Contaminant Levels (MCLs) 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;

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

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

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

[17] URS, 2009, pp. 4-5:4-16.

- Human exposure and risks of adverse health effects in the general population and sensitive subpopulations;
- Analytical methods of detection;
- Technical feasibility; and
- Impacts of regulation on water systems, the economy and public health.

After reviewing health effects studies and considering the risk to sensitive subpopulations, EPA 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 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 Coliform (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

Inorganic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
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
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

Organic Chemicals

Contaminant	CAS number	MCLG (mg/L)	MCL or TT (mg/L)
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
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		Non-corrosive
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.

2.3.3.2 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 the Department, 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.[18]

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

Contact with the Department 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 10 NYCRR), NYSDOH oversees the suitability of water for human consumption. Section 5-1.30 of

[18] 6 NYCRR 601 – http://www.dec.ny.gov/regs/4445.html.

10 NYCRR[19] 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.

2.3.4 Public Water Systems

Public water systems in New York range in size from that of 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 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 water systems (CWS) and non-community water systems (NCWS). NCWSs include non-transient non-community (NTNC) and transient non-community (TNC) water systems. NYSDOH regulations contain the definitions listed in Table 2.4.

[19] 10 NYCRR 5-1.30 – http://www.health.state.ny.us/nysdoh/phforum/nycrr10.htm.

Table 2.4 - Public Water System Definition[20]

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. **Non-transient 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.

2.3.4.1 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 NYSDOH, in 1981, identified 18 Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the State. These are defined in the Division of Water (DOW) Technical and Operational Guidance Series (TOGS) 2.1.3[21] 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

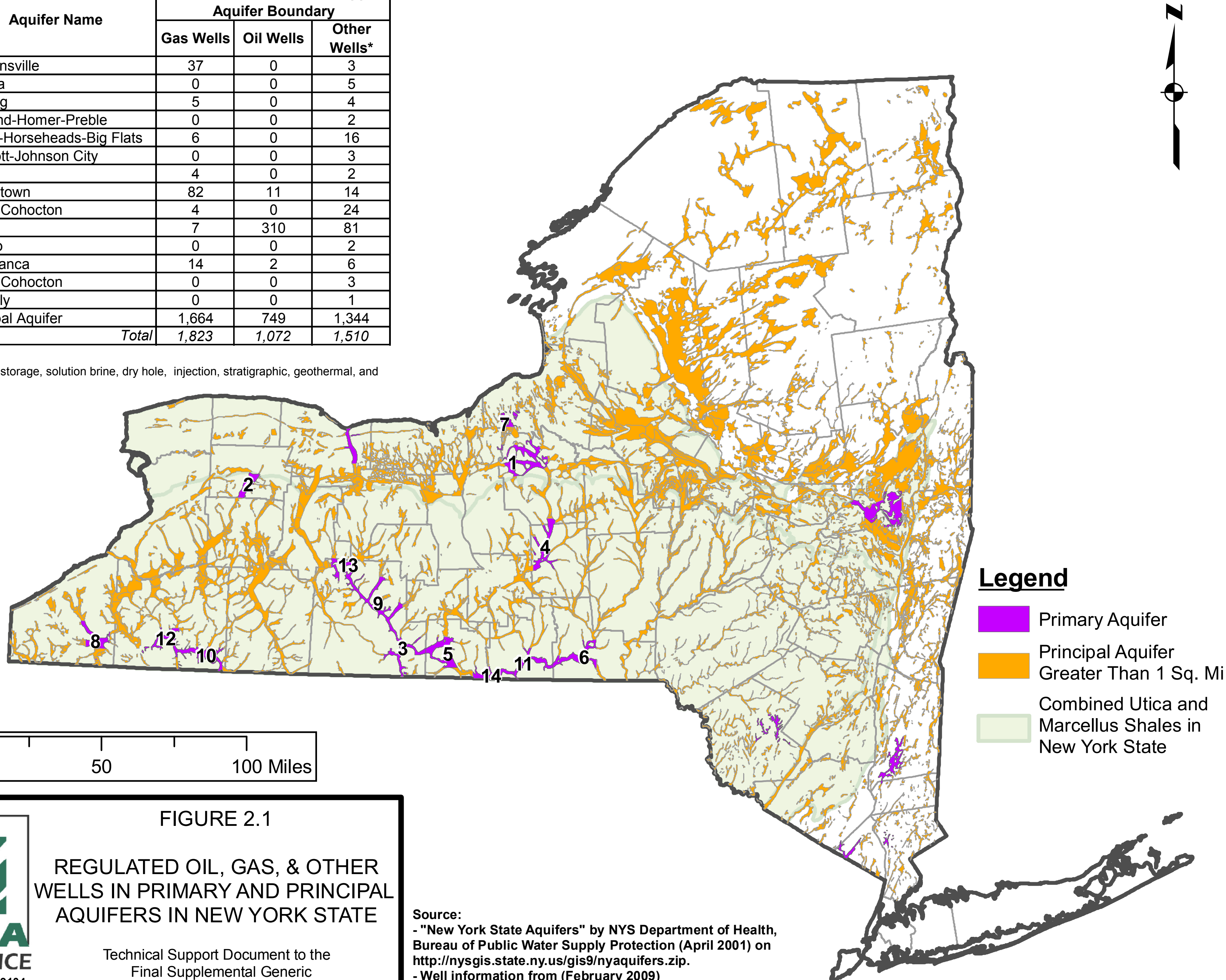
[20] 10 NYCRR, Part 5, Subpart 5-1 Public Water Systems (Current as of: October 1, 2007); SUBPART 5-1; PUBLIC WATER SYSTEMS; 5-1.1 Definitions. (Effective Date: May 26, 2004).

[21] 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.



ALPHA GEOSCIENCE

Alpha Project No. 09104

FIGURE 2.1

REGULATED OIL, GAS, & OTHER WELLS IN PRIMARY AND PRINCIPAL AQUIFERS IN NEW YORK STATE

Technical Support Document to the Final Supplemental Generic Environmental Impact Statement

Source:
- "New York State Aquifers" by NYS Department of Health, Bureau of Public Water Supply Protection (April 2001) on http://nysgis.state.ny.us/gis9/nyaquifers.zip.
- Well information from (February 2009) http://www.dec.ny.gov/energy/1603.html

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.[22]

2.3.4.2 Public Water Supply Wells

NYSDOH estimates that over two million New Yorkers outside of Long Island are served by public groundwater supplies.[23] 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.[24]

2.3.5 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 water 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,"[25] installed by a certified Department-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 1992 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.[26]

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.[27]

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[22] Alpha, 2009, p. 3-2.

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

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

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

[26] NYSDEC, 1992, GEIS, p. 8-22.

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

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:

> 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.[28]

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 1992 GEIS proposes a 150-foot setback.[29]

For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS[30] and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS.[31] 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.[32]

2.3.6 History of Drilling and Hydraulic Fracturing in Water Supply Areas

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

[28] NYSDOH - http://www.health.ny.gov/environmental/water/drinking/part5/append5b/docs/fs5_susceptible_water_sources.pdf.

[29] NYSDEC, 1992, GEIS, p. 8-16.

[30] 6 NYCRR Part 550.3(ai).

[31] 6 NYCRR Part 550.3(at).

[32] Alpha, 2009, p. 3-3.

located within the boundaries of Principal Aquifers. Another 1,510 storage, solution brine, 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.[33]

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

No documented instances of groundwater contamination from previous horizontal drilling or hydraulic fracturing projects in New York are recorded in the Department's well files or records of complaint investigations. No documented incidents of groundwater contamination in public water supply systems could be recalled 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.[34]

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 staff were dispatched to investigate the problem. The Department shut down drilling operations and ordered the well plugged when it became apparent that continued drilling at the wellsite would cause

[33] Alpha, 2009, p. 3-3.

[34] Alpha, 2009, p. 3-3.

turbidity to increase above what had already been experienced. The operator immediately 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 would not typically cause the excessive turbidity event seen at the Brookfield wells. The Department 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."

2.3.7 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.[35] 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 water bodies. Since all of New York State's land area is incorporated into watersheds, all oil and gas drilling that has occurred since 1821 has occurred within watersheds, specifically, in 13 of the State's 17 watersheds. 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.

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 2.2.

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

2.3.7.1 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). Approximately 18.5 % of the surface area 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 NYC's West of Hudson Watershed; the Basin supplies about half of NYC's drinking water and 100% of Philadelphia's supply.

The 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 the Department 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.[36]

2.3.7.2 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. Approximately 24 % 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.

[36] http://www.state.nj.us/drbc/naturalgas.htm

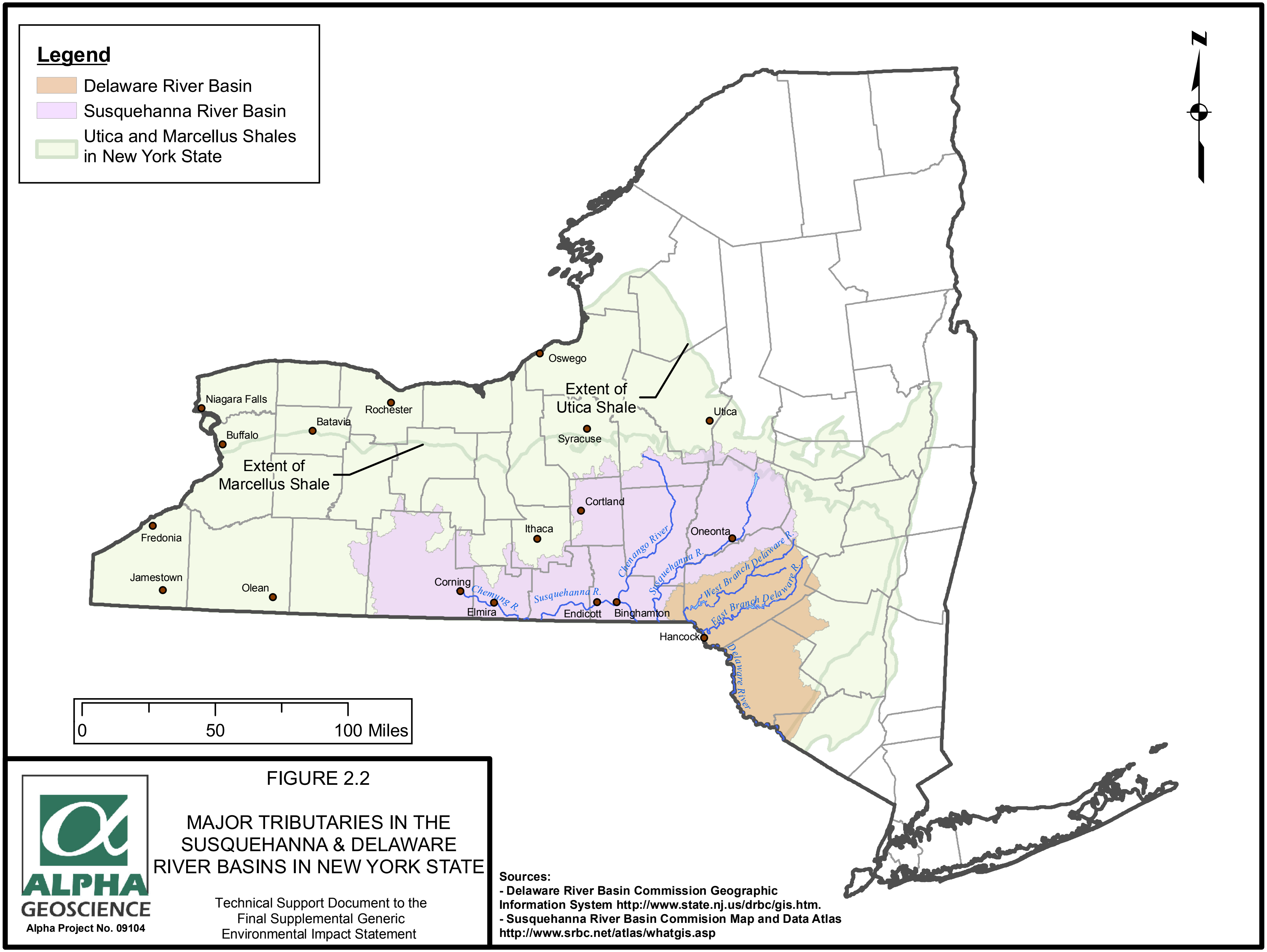

FIGURE 2.2

MAJOR TRIBUTARIES IN THE SUSQUEHANNA & DELAWARE RIVER BASINS IN NEW YORK STATE

Technical Support Document to the Final Supplemental Generic Environmental Impact Statement

The 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 the Department's Commissioner, and the Department 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 (gpd). 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 gpd. 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 gpd as an annual average.[37]

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

2.3.8 Water Resources Replenishment[38]

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).

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

[38] Alpha, 2009, p. 3-26.

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, which 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.

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 ensure 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; and
- 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.

2.3.9 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, town, city or village basis and are available through the FEMA Map Service Center.[39] They may also be viewed at local government facilities, the Department, 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 ensure 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 (also 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 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

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

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.

2.3.9.1 Analysis of Recent Flood Events[40]

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 FEMA 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.

2.3.9.2 Flood Zone Mapping[41]

Flood zones are geographic areas that 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.

[40] Alpha, 2009, p. 3-30.

[41] Alpha, 2009, p. 3-30.

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 Counties. 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. Mapping the areas affected by recent flooding in the Susquehanna River Basin currently is underway and is scheduled to be published in late 2012 (SRBC, 2011). Updated FIRMs are being prepared for communities in Delaware County affected by recent flooding and are expected to be released in late 2012 (Delaware County, 2011).

According to the DOW, preliminary county-wide FIRMs have been completed and adopted by Sullivan County. County-wide FIRMs for Broome and Delaware Counties are scheduled to be completed in late 2012.

2.3.9.3 Seasonal Analysis[42]

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

[42] Alpha, 2009, p. 3-31.

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.

2.3.10 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 ECL, provides the Department and the Adirondack Park Agency (APA) 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 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 the Department and APA to map those wetlands that are protected by the FWA. In addition, the law requires the Department and APA to classify wetlands. Inside the Adirondack Park, wetlands are classified according to their vegetation cover type. Outside the Park, the Department classifies wetlands according to 6 NYCRR Part 664, Wetlands Mapping and Classification.[43] 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,

[43] 6 NYCRR 664 - http://www.dec.ny.gov/regs/4612.html.

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 6 NYCRR Part 663, Freshwater Wetlands Permit Requirement Regulations.[44] 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.

2.3.11 Socioeconomic Conditions[45]

The Marcellus and Utica Shales are the most prominent shale formations in New York State. The prospective region for the extraction of natural gas from these formations generally extends 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 (Figure 2.3). This region covers all or parts of 30 counties. Fourteen counties are entirely within the area underlain by the Marcellus and Utica Shales, and 16 counties are partially within the area.

Due to the broad extent of the prospective region for the extraction of natural gas from the Marcellus and Utica Shales, the socioeconomic analysis in the SGEIS focuses on representative regional and local areas of New York State where natural gas extraction may occur, and also provides a statewide analysis. The three regions were selected to evaluate differences between areas with a high, moderate and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

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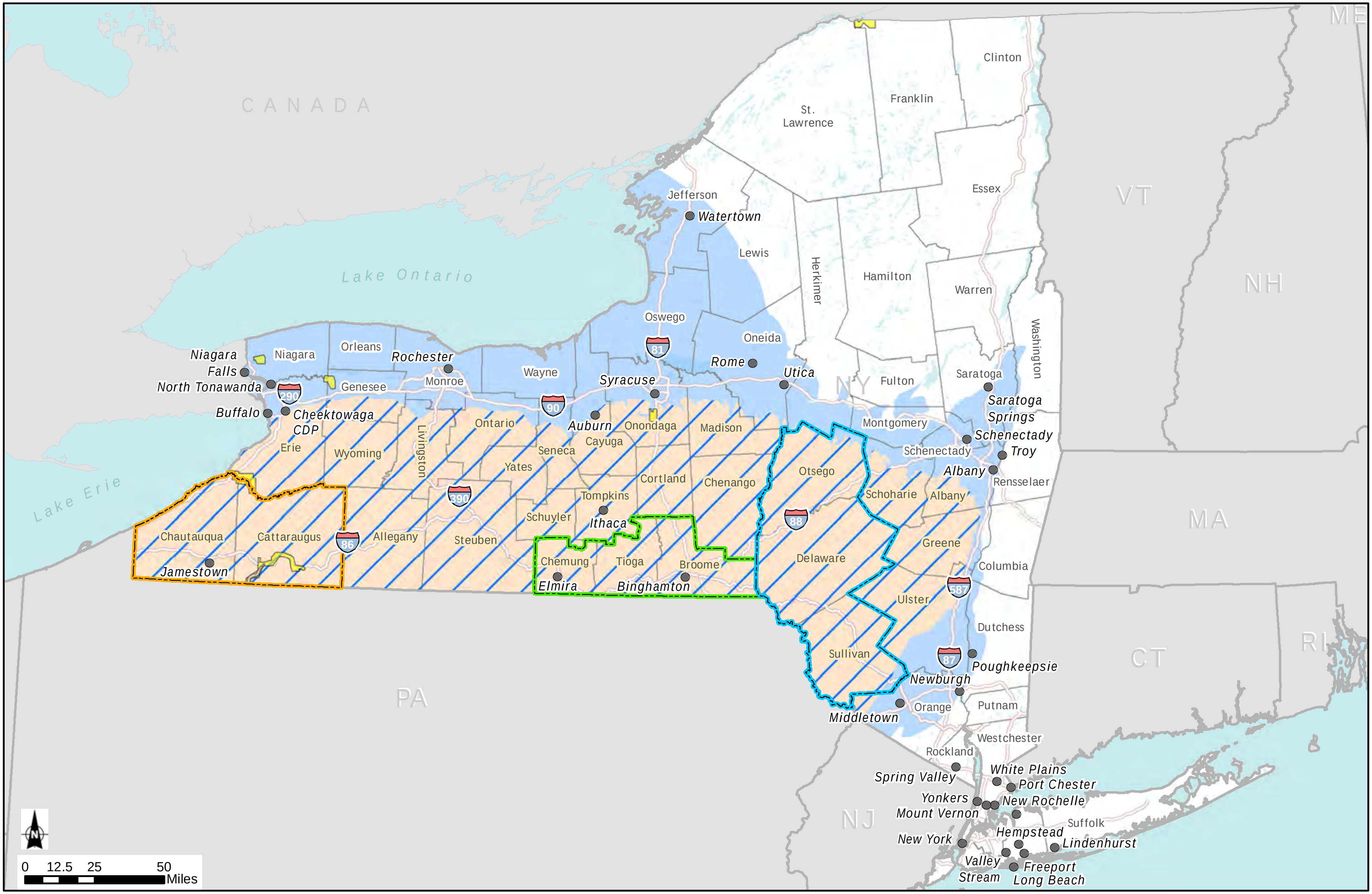
44 6 NYCRR 663 - http://www.dec.ny.gov/regs/4613.html.

45 Subsection 2.4.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.



Representative Regions

- Region A
- Region B
- Region C

CDP = Census Designated Place

- Place with Year 2010 Population Greater than 25,000
- Major Water Bodies
- County Boundary
- State Boundary
- Tribal Lands Boundary
- Marcellus Shale Extent in New York State
- Utica Shale Extent in New York State
- Extent of Marcellus and Utica Shales in NYS

Figure 2.3: Representative Regions within the Marcellus Shale Extent in New York

Source: ESRI, 2010; USGS, 2002

- Region A: Broome County, Chemung County, and Tioga County (Figure 2.4a);
- Region B: Delaware County, Otsego County, and Sullivan County (Figure 2.4b); and
- Region C: Cattaraugus County and Chautauqua County (Figure 2.4c);

Region A is defined as a high-potential production area. Wells in Broome, Chemung, and Tioga Counties are expected to yield some of the highest production of shale gas, based on the geology, thermal maturity of the organic matter, and other geochemical factors of the Marcellus and Utica Shale formations. Due to the proximity to active gas drilling in these counties, and neighboring counties in Pennsylvania, the associated infrastructure (pipelines) has already been developed. With the associated infrastructure in place, developers are expected to begin development of wells in this area if development in New York State is approved. Region A encompasses urban/suburban land uses associated with the larger cities of Binghamton and Elmira, as well as rural settings. In addition, conventional natural gas development has occurred in this area.

Region B is defined as an average-potential production area. High-volume hydraulic-fracturing is expected to occur in portions of Delaware, Otsego, and Sullivan Counties, but the production of shale gas is not anticipated to reach the levels expected in Region A. Region B is largely rural and encompasses part of the Catskill Mountains. Development in this region would be limited by the exclusion of drilling from the New York City watershed and state-owned lands (e.g., the Forest Preserve) in the Catskill Mountains. To date, only exploratory natural gas well development has occurred in this region.

Region C is defined as a low-potential production area. Although Chautauqua and Cattaraugus Counties are within the footprints of both the Utica and Marcellus Shales, they are outside of the fairways for both shales; thus, horizontal wells in this region would not be expected to yield enough gas to be economically feasible. However, thousands of vertical gas wells exist in conventional formations, and additional vertical wells would likely be constructed. If the price of gas increases or drilling technology advances, gas production in the Utica or other formations in this region may become more feasible. Region C is largely rural, and conventional natural gas development has been occurring in this area for many years.

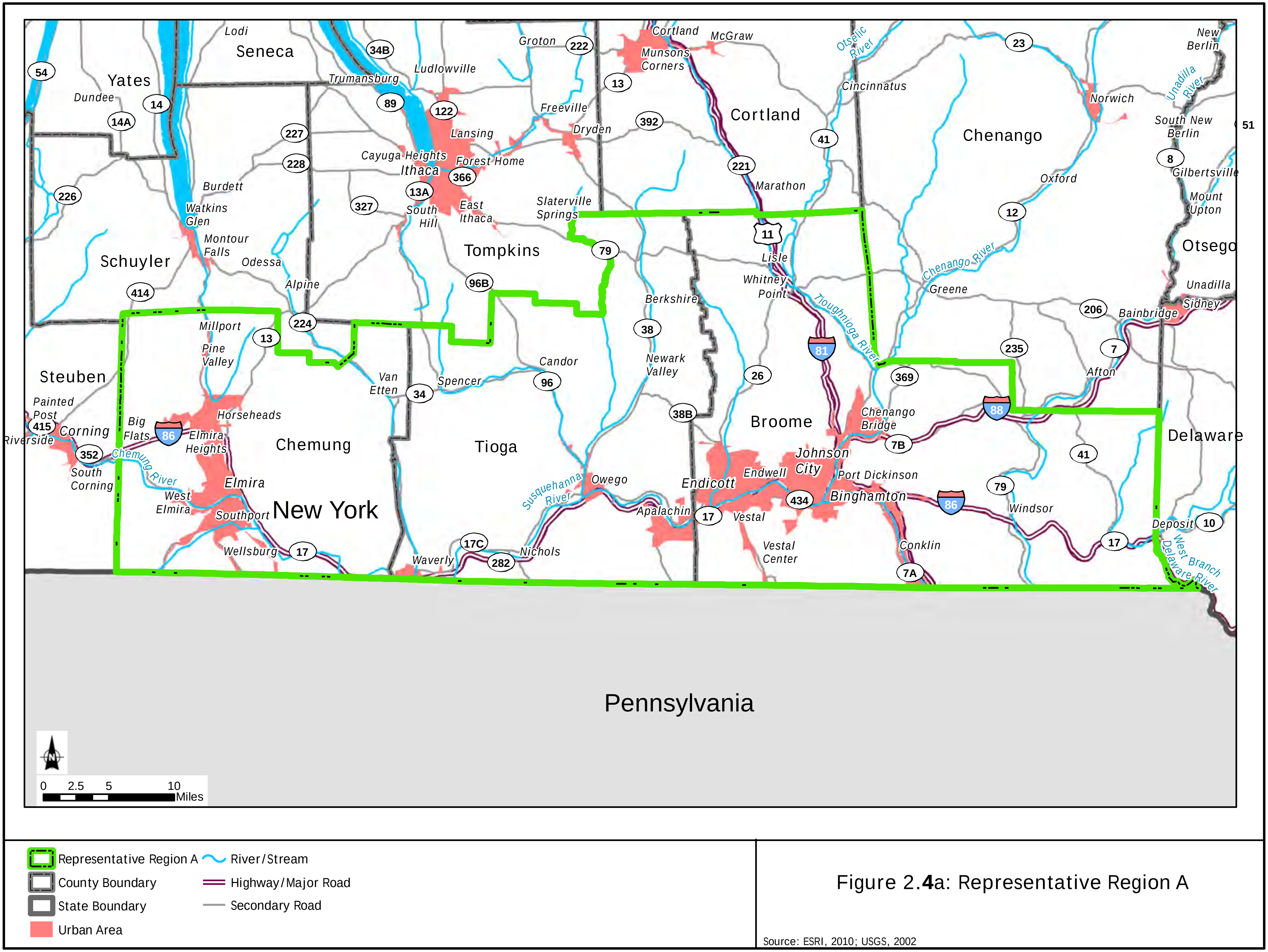


Figure 2.4a: Representative Region A

Source: ESRI, 2010; USGS, 2002

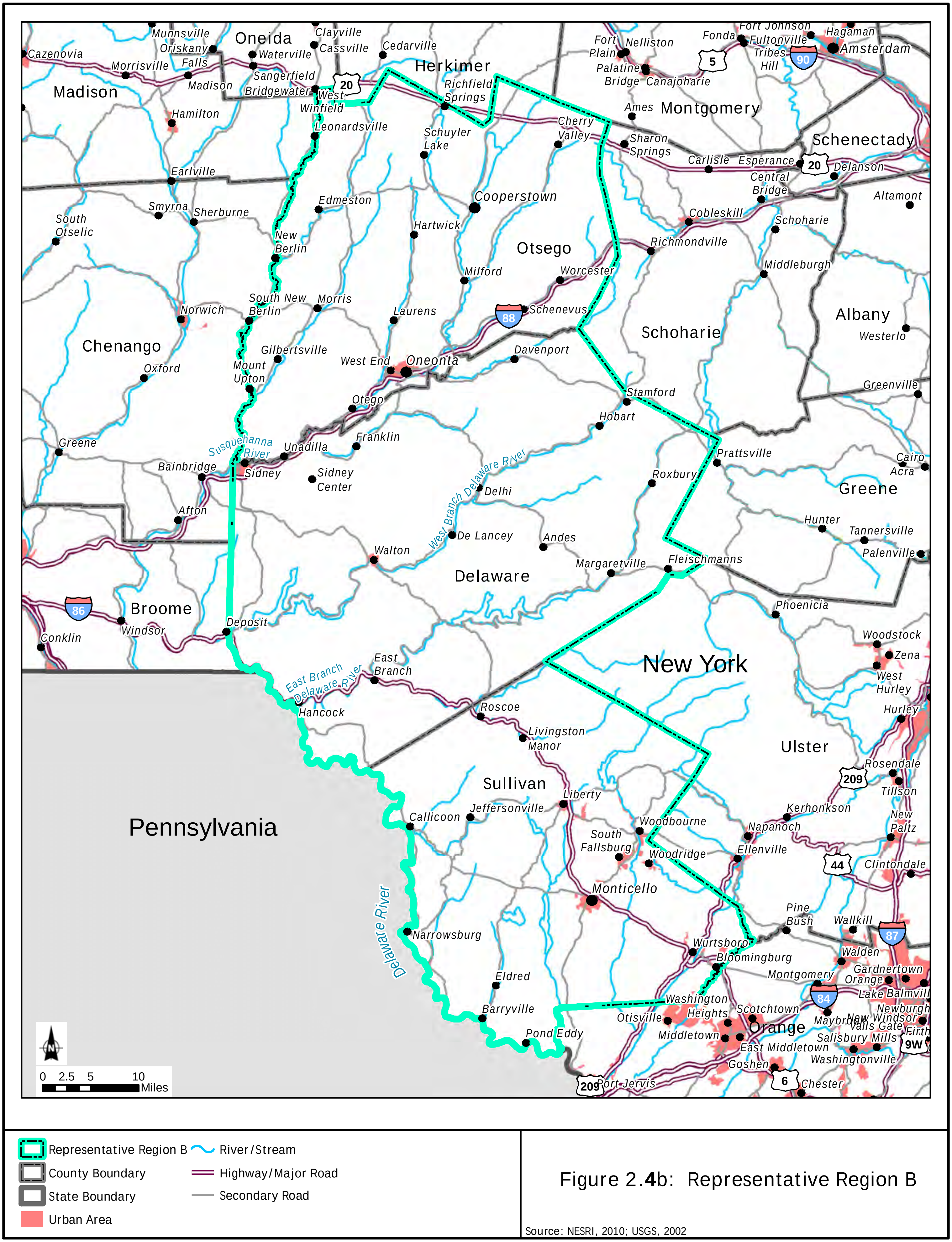


Figure 2.4b: Representative Region B

Source: NESRI, 2010; USGS, 2002

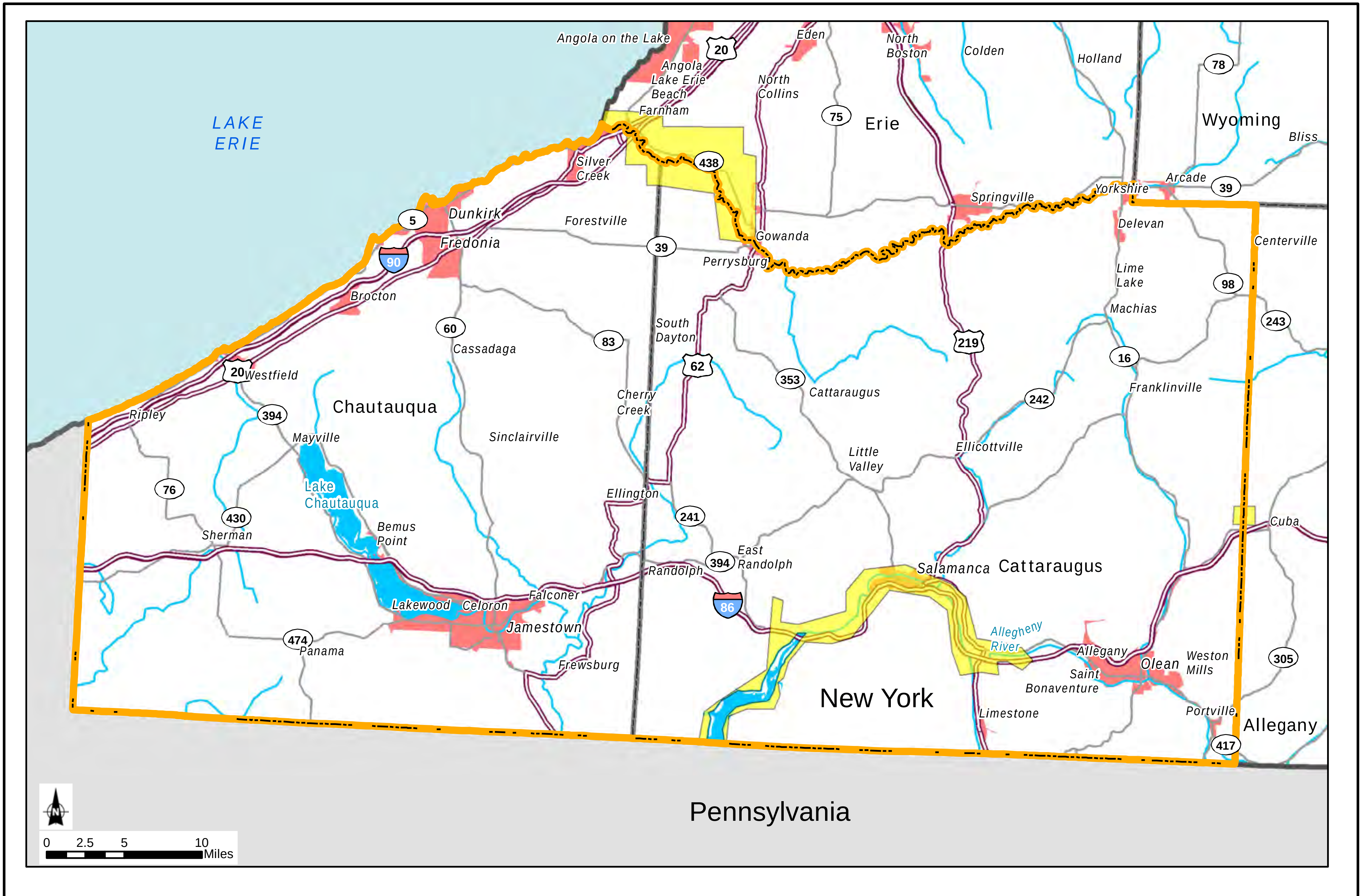


Figure 2.4c: Representative Region C

Source: NESRI, 2010; USGS, 2002

While these regions are being analyzed as a way to assess the impacts on representative local communities, actual development would not be limited to these regions, and impacts similar to those described in Section 6 could occur anywhere where high-volume hydraulic-fracturing wells are developed. Therefore, this section also provides the socioeconomic baseline for the state as a whole.

A description of the baseline socioeconomic conditions includes Economy, Employment and Income (Subsection 2.3.11.1); Population (Subsection 2.3.11.2); Housing (Subsection 2.3.11.3); Government Revenues and Expenditures (Subsection 2.3.11.4); and Environmental Justice (EJ) (Subsection 2.3.11.5). Socioeconomic impacts are discussed in Chapter 6, and socioeconomic mitigation measures are discussed in Chapter 7.

2.3.11.1 Economy, Employment, and Income

This subsection provides a discussion of the economy, employment and income for New York State, and the local areas within each of the three representative regions (Region A, B and C), focusing on the agricultural and tourism industries, as well as existing natural gas development.

Natural gas development is expected to benefit other industries as equipment, material, and supplies are purchased by the natural gas industry and workers spend their wages in the local economy. These positive impacts are discussed in more detail in Section 6. However, as agriculture and tourism relate to uses of the land that may be impacted by natural gas development, those industries are discussed in more detail herein, and potential impacts from both a land use and economic perspective are discussed in Chapter 6.

Several data sources were used to describe the baseline economy, employment, and income for New York State and the local areas, including the U.S. Census Bureau (USCB) and the New York State Department of Labor (NYSDOL). Data from the *2010 Census of Population and Housing* were used to identify major employment sectors for the state and the representative regions. Data from the census is self-reported by individuals and is aggregated to provide general information about the labor force from very small to large geographic areas on a cross-sectional or one-time basis.

Detailed data on employment and wages, by industry, was obtained from the NYSDOL's quarterly census of employment and wages (QCEW). The NYSDOL collects employment and wage data for all employers liable for unemployment insurance. These data were used to provide information on wages and for more detailed information on employment in the travel and tourism and oil and gas sectors. All of the labor statistics from the NYSDOL and USCB are based on the North American Industry Classification System, which is the standard system used by government agencies to classify businesses, although the data may be grouped differently for reporting purposes. Data on agricultural workers is taken from the U.S. Census of Agriculture, which is collected every 5 years, and provides information on the value of farm production and agricultural employment in the state and local areas. Although the data referenced within this section were collected by government agencies using different methodologies, all data were used to support an overall portrait of the statewide and local economies.

New York State

Table 2.5 presents total employment by industry within New York State. As shown, New York State has a large and diverse economy. The largest employment sector in the state is educational, health, and social services, accounting for approximately 26.2% of the total employed labor force (USCB 2009a). Other large sectors are professional, scientific, management, administrative, and waste management services (10.8%); and retail trade (10.5%). Several of the largest private employers in New York State include NY Presbyterian Healthcare System (29,000 employees); Walmart (28,000 employees); Citigroup (27,000 employees); IBM Corporation (21,000 employees); and JP Morgan Chase (21,000 employees).

Table 2.5 - New York State: Area Employment by Industry, 2009 (New August 2011)

Sector	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	54,900	0.6
Construction	548,018	6.0
Manufacturing	672,481	7.4
Wholesale trade	266,946	2.9
Retail trade	959,414	10.5
Transportation and warehousing, utilities	482,768	5.3
Information	299,378	3.3
Finance, insurance, real estate, and renting/leasing	789,372	8.7
Professional, scientific, management, administrative, and waste management services	981,317	10.8
Educational, health, and social services	2,385,864	26.2
Arts, entertainment, recreation, accommodation, and food services	764,553	8.4
Other services (except public administration)	449,940	4.9
Public administration	447,645	4.9
Total	9,102,596	

Source: USCB 2009a.

In 2010, New York State had a total gross domestic product (GDP, i.e., the value of the output of goods and services produced by labor and property located in New York State) of approximately $1.16 trillion (USDOC 2010).

Each region of the state contributes to the state's GDP in different ways. New York City is the leading center of banking, finance, and communications in the United States, and thus has a large number of workers employed in these industrial sectors. In contrast, the economies of large portions of western and central New York are based on agriculture. Manufacturing also plays a significant role in the overall economy of New York State; most manufacturing occurs in the upstate regions, predominantly in the cities of Albany, Buffalo, Rochester, and Syracuse.

Table 2.6 provides total and average wages, by industry, as reported by NYSDOL for 2009.

Table 2.6 - New York State: Wages by Industry, 2009 (New August 2011)

Industry	Total Wages ($ millions)	Average Wage
Total, all industries	$481,690.6	$57,794
Agriculture, forestry, fishing, hunting	640.4	$28,275
Mining	265.5	$55,819
Construction	19,336.0	$59,834
Manufacturing	27,098.4	$57,144
Wholesale trade	22,797.7	$69,282
Retail trade	25,130.8	$29,202
Transportation and warehousing	9,302.9	$42,477
Utilities	3,633.7	$92,469
Information	22,124.3	$87,970
Finance and insurance	86,303.4	$173,899
Real estate and renting/leasing	9,360.2	$52,417
Professional and technical services	48,815.9	$87,136
Management of companies and enterprises	15,648.4	$119,804
Administrative and waste services	16,354.4	$40,546
Educational services	13,606.9	$46,772
Health, and social assistance	55,486.7	$44,104
Arts, entertainment, and recreation	6,154.3	$44,246
Accommodation, and food services	12,178.7	$21,369
Other services (except public administration)	10,732.4	$33,602
Public administration	75,828.4	$52,594

Source: NYSDOL 2009a.

The total labor force in New York State in 2010 was approximately 9,630,900 workers. In 2010, the annual average unemployment rate across New York State was 8.6% (Table 2.7). Between 2000 and 2010, the size of the labor force increased by 5.1%, while the unemployment rate nearly doubled.

Table 2.7 - New York State: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Total labor force	9,167,000	9,630,900
Employed workers	8,751,400	8,806,800
Unemployed workers	415,500	824,100
Unemployment rate (%)	4.5	8.6

Source: NYSDOL 2010a.

In 2009, the per capita income for New York State was $30,634, and 13.9% of the population lived below the poverty level (Table 2.8). Over the past decade, per capita income has increased by 31.0%, and the percentage of individuals living below the poverty level has decreased by 0.7%.

Table 2.8 - New York State: Income Statistics, 1999 and 2009 (New August 2011)

	1999	**2009**
Per capita income	$23,389	$30,634
% Below the poverty level[1]	14.6	13.9

Source: USCB 2000a, 2009b.
[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The Empire State Development Corporation has identified 16 industry clusters for New York State. Industry clusters define a set of interdependent and connected companies and businesses that help to support a local economy, such as automobile manufacturing in Detroit, Michigan, and information technology in the Silicon Valley of California. Industry clusters for the state include: back office and outsourcing; biomedical; communications, software, and media services; distribution; electronics and imaging; fashion, apparel, and textiles; financial services; food processing; forest products; front office and producer services; industrial machinery and services; information technology services; materials processing; miscellaneous manufacturing; transportation equipment; and travel and tourism.

Travel and tourism is a large industry in New York State, ranking third in employment of the 16 industry clusters in the state. New York State has many notable attractions, including natural areas (Niagara Falls, the Finger Lakes, and the Adirondack, Catskill, and Allegany Mountains); cultural attractions (museums, arts, theater), and historic sites, many of which are described in Section 2.3.12, Visual Resources. The travel and tourism sector draws from several industries, as shown in Table 2.9 and Table 2.10. Approximately 351,130 persons were employed in the travel and tourism sector in New York State in 2009, including food service (96,990 jobs); culture, recreation, and amusements (84,550 jobs); accommodations (81,780 jobs); passenger transportation (73,180 jobs); and travel retail (14,630) (see Table 2.9). In 2009, wages earned by persons employed in the travel and tourism sector was approximately $12.9 billion dollars, or approximately 2.7% of all wages earned in New York State (NYSDOL 2009b) (see Table 2.10).

In 2009, visitors to New York State spent approximately $4.5 billion in the state (Tourism Economics 2010).

Table 2.9 - New York State: Employment in Travel and Tourism, 2009 (New August 2011)

Industry Group	Number of Jobs	% of Total
Accommodations	81,780	23.3%
Culture, recreation and amusements	84,550	24.1%
Food service	96,990	27.6%
Passenger transportation	73,180	20.8%
Travel retail	14,630	4.2%
Total	351,130	100%

Source: NYSDOL 2009b.

Table 2.10 - New York State: Wages in Travel and Tourism, 2009 (New August 2011)

	Total Wages ($ millions)	Average Wage
Accommodations	$2,928.3	$35,800
Culture, recreation and amusements	$4,355.5	$51,500
Food service	$1,840.9	$18,980
Passenger transportation	$3,478.4	$47,532
Travel retail	$324.1	$22,153
Total	$12,927.3	$36,800

Source: NYSDOL 2009b.

Agriculture is also an important industry for New York State. Table 2.11 provides agricultural statistics for New York State. Approximately 36,352 farms are located in New York State, encompassing 7.2 million acres of land, or 23% of the total land area of the state.

The value of agricultural production in 2009 was $4.4 billion dollars. New York State is a leading producer of milk, fruits (apples, grapes, cherries, pears), and fresh vegetables (sweet corn, onions, and cabbage). Most of the state’s field crops (corn, soybeans, and wheat) support its dairy industry (USDA 2007).

Most counties in New York State have placed agricultural land in state-certified agricultural districts, which are managed by the New York State Department of Agriculture and Markets. Farmlands within agricultural districts are provided legal protection, and farmers benefit from preferential real property tax assessment and protection from restrictive local laws, government-funded acquisition or construction projects, and private nuisance suits involving agricultural practices. Article 25-AA of Agriculture and Markets Law authorizes the creation of local agricultural districts pursuant to landowner initiative, preliminary county review, state certification, and county adoption.

The acreage of land in agricultural districts in New York State is provided on Table 2.11.

Table 2.11 - New York State: Agricultural Data, 2007 (New August 2011)

Number of farms	36,352
Land in farms	7,174,743 acres
Average size of farm	197 acres
Market value of products sold	$4,418.6 million
Principal operator by primary occupation	
Farming	19,624
Other	16,728
Hired farm labor	59,683
Land in state-designated agricultural districts	8,873,157 acres

Source: USDA 2007; NYSDAM 2011.

The oil and gas extraction industry is a relatively small part of the economy of New York State. According to data provided by the U.S. Department of Commerce (USDOC), Bureau of Economic Analysis (BEA), the oil and gas extraction industry accounted for only 0.004% of New York State's GDP in 2009. For comparison purposes, at the national level, the oil and gas extraction industry's 2009 share of the U.S. GDP was 1.01% (USDOC 2010). Consequently, the oil and gas extraction industry is currently of less relative economic importance in New York State than it is at the national level.

The natural gas extraction industry is linked to other industries in New York State through its purchases of their output of goods and services. As a natural gas extraction company increases the number of wells it drills, it needs additional supplies and materials (e.g., concrete) from other industries to complete the wells. The other industries, in turn, need additional goods and services from their suppliers to meet the additional demand. The interrelations between various industries are known as linkages in the economy.

To provide a sense of the direction and magnitude of the linkages for the oil and gas extraction industry, Table 2.12 shows the impact of a $1 million increase in the final demand in the oil and gas extraction industry on the value of the output of other industries in New York State. The data used to construct the table were drawn from the estimates contained in the BEA's Regional Input-Output Modeling System II (RIMS II). In constructing the table, the initial $1 million increase in the final demand for the output of the oil and gas extraction industry was deducted from the change in its output value to leave just the increase in its output value caused by its purchases of goods and services from other companies in the mining industry, of which it forms a part.

Table 2.12 - New York: Impact of a $1 Million Dollar Increase in the Final Demand in the Output of the Oil and Gas Extraction Industry on the Value of the Output of Other Industries (New August 2011)

Industry	Change in the Value of Output
Real estate and rental and leasing	$47,100
Professional, scientific, and technical services	$30,500
Management of companies and enterprises	$27,600
Construction	$24,300
Manufacturing	$21,000
Finance and insurance	$15,700
Utilities	$12,300
Wholesale trade	$10,800
Information	$7,700
Administrative and waste management services	$5,900
Transportation and warehousing	$3,900
Retail trade	$3,100
Other services	$2,600
Arts, entertainment, and recreation	$1,600
Mining	$1,500
Food services and drinking places	$700
Accommodation	$600
Health care and social assistance	$300
Educational services	$200

Source: US Bureau of Economic Analysis 2011.

As shown in the table above, the oil and gas extraction industry is linked through its purchases of inputs to 18 other major industries (out of a total of 20 industries used by the Regional Input-Output Modeling System II). The largest linkages are to real estate and rental and leasing; professional, scientific, and technical services; management of companies and enterprises; and construction. In total, a $1 million increase in the final demand for the output of the mining industry is estimated to lead to an increase of an additional $217,400 in final output across all industries.

The oil and gas extraction industry accounts for a very small proportion of total employment in New York State. According to the NYSDOL, the oil and gas extraction industry employed 362 people in the state (i.e., less than 0.01% of the state's total employment) (NYSDOL 2009a). Although the number of people employed in the oil and gas extraction industry in New York State is relatively small, the industry has experienced sustained growth in employment during the last few years. Employment in the oil and gas extraction industry in New York State between 2000 and 2010 is shown on Table 2.13. As shown, employment in the industry more than doubled from 2003 to 2010, with the addition of 252 employees during that period.

Table 2.13 - New York State: Employment in the Oil and Gas Extraction Industry, 2000-2010 (New August 2011)

Year	**Employment**
2000	165
2001	188
2002	193
2003	196
2004	137
2005	163
2006	236
2007	281
2008	341
2009	362
2010	448

Source: NYSDOL 2000 -2008, 2009a, 2010b.
Note: 2010 data are provisional.

A general indication of the types of jobs held by those working in the natural gas extraction industry is provided by looking at the occupational distribution of employment within the oil and gas extraction industry at the national level. Table 2.14 presents employment data on the 20 occupations that accounted for the largest shares of employment in the oil and gas extraction industry at the national level in 2008 (BLS 2011).

Table 2.14 - Most Common Occupations in the U.S. Oil and Gas Extraction Industry, 2008 (New August 2011)

Occupation	% of Industry Employment
Roustabouts, oil and gas	7.45
Petroleum pump system operators, refinery operators, and gaugers	6.07
Petroleum engineers	5.43
Wellhead pumpers	5.41
Accountants and auditors	4.88
General and operations managers	4.18
Geoscientists, except hydrologists and geographers	3.88
Geological and petroleum technicians	3.27
Office clerks, general	3.03
Bookkeeping, accounting, and auditing clerks	2.93
Executive secretaries and administrative assistants	2.77
Secretaries, except legal, medical, and executive	2.49
Service unit operators, oil, gas, and mining	2.50
First-line supervisors/managers of construction trades and extraction workers	2.27
All other engineers	1.74
Business operation specialists, all others	1.72
Financial analysts	1.56
Maintenance and repair workers, general	1.43
Real estate sales agents	1.35
Rotary drill operators, oil and gas	1.33

Source**:** BLS 2011.

The oil and gas extraction industry is a relatively high-wage industry. In 2009, the average annual wage paid to employees in the industry was $83,606, which is almost 45% above the average annual wages of $57,794 paid to employees across all industries in the state (NYSDOL 2009a). However, national data show that workers in the mining, quarrying, and oil and gas extraction industry have the longest work week among all of the nonagricultural industries. The average work week for all workers aged over 16 in the nonagricultural industries was 38.1 hours long, while the average work week for those in the mining, quarrying, and oil and gas extraction industry was 49.4 hours long (i.e., an almost 30% longer average work week) (BLS 2010).

Table 2.15 presents total and average wages for the oil and gas industry and all industries in New York State. The oil and gas industry was a marginal contributor to total wages in New York State, accounting for $30 million in 2009, or less than 1/100th of a percentage point of total wages across all industries (NYSDOL 2009a).

Table 2.15 - New York State: Wages in the Oil and Gas Industry, 2009 (New August 2011)

	Total Wages ($ million)	**Average Wage**
Oil and gas industry	$30.3	$83,606
Total, all industries	$481,690.6	$57,794

Source: NYSDOL 2009a.

Compared to other parts of the country, New York State currently is a relatively minor natural gas producer. Based on data on natural gas gross withdrawals and production published by the Energy Information Administration (EIA), New York State accounted for 0.2% of the United States' total marketed natural gas production in 2009. During the same period, New York ranked 23rd out of 34 gas-producing areas in the U.S., which included states and the federal Offshore Gulf of Mexico (EIA 2011).

New York State is, however, a major natural gas consumer. Based on data on natural gas consumption by end-use published by the EIA, New York State accounted for 5% of the United States' total consumption of natural gas in 2009. During the same period, New York State was ranked as the 4th largest natural gas consumer among the nation's states (EIA 2011).

By combining the EIA's data on the total consumption and marketed production of natural gas in 2009, there was a difference of approximately 1.1 Tcf between New York State's total consumption and marketed production of natural gas. In 2009, New York State's marketed production was equal to 3.9% of its total consumption.

Table 2.16 shows natural gas production in New York State between 1985 and 2009.

Table 2.16 - New York State: Natural Gas Production, 1985-2009 (New August 2011)

Year	Natural Gas Production (Bcf)
1985	33.1
1986	34.8
1987	29.5
1988	28.1
1989	25.7
1990	25.1
1991	23.4
1992	23.6
1993	22.1
1994	20.5
1995	18.7
1996	18.3
1997	16.2
1998	16.7
1999	16.1
2000	17.7
2001	28.0
2002	36.8
2003	36.0
2004	46.9
2005	55.2
2006	55.3
2007	54.9
2008	50.3
2009	44.9

Source: NYSDEC 1994-2009.

As shown in the table, natural gas production in New York State generally declined between 1986 and 1999, increased steeply until 2005, and then declined toward the end of that decade.

Other indicators of the level of activity in the natural gas extraction industry in New York State are the number of well permits granted, the number of wells completed, and the number of active wells in each year. Table 2.17 shows the number of permits granted for gas wells, the number of gas wells completed, and the number of active gas wells in New York State between 1994 and 2009.

Table 2.17 - Permits Issued, Wells Completed, and Active Wells, NYS Gas Wells, 1994-2009 (New August 2011)

Year	Permits for Gas Wells	Gas Wells Completed	Active Gas Wells
1994	58	97	6,019
1995	38	31	6,216
1996	45	31	5,869
1997	53	22	5,741
1998	68	41	5,903
1999	74	28	5,756
2000	78	112	5,775
2001	127	103	5,949
2002	97	43	5,773
2003	81	31	5,906
2004	133	70	6,076
2005	180	104	5,957
2006	353	191	6,213
2007	386	271	6,683
2008	429	270	6,675
2009	246	134	6,628

Source: NYSDEC 1994-2009.

As with natural gas production, well permits and completions experienced a considerable increase in the 2000s compared to the 1990s, before declining in the late 2000s. This trend most likely reflects the discovery and development of commercial natural gas reserves in the Black River formation in the southern Finger Lakes area along with the impact of higher natural gas prices in the 2000s compared to the 1990s (see Table 2.18). As shown in Table 2.17, active natural gas wells reached a low point in 1997 when only 5,741 wells were active. By 2007, this figure had reached a peak of 6,683 wells.

The level of activity in the natural gas extraction industry is related to the price of natural gas. Table 2.18 shows the average wellhead price for New York State's natural gas for the years 1994 to 2009 inclusive.

Table 2.18 - Average Wellhead Price for New York State’s Natural Gas, 1994-2009 (New August 2011)

Year	Price per Mcf
1994	$2.35
1995	$2.30
1996	$2.21
1997	$2.56
1998	$2.46
1999	$2.19
2000	$3.75
2001	$4.85
2002	$3.03
2003	$5.78
2004	$6.98
2005	$7.78
2006	$7.13
2007	$8.85
2008	$8.94
2009	$4.25

Source: NYSDEC 1994-2009.

As shown in the table, the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009.

Table 2.19 shows the market value of New York State’s natural gas production, which is the price multiplied by the total production.

Table 2.19 - Market Value of New York State’s Natural Gas Production, 1994-2009 (New August 2011)

Year	Millions of Dollars
1994	$48.1
1995	$43.0
1996	$40.6
1997	$41.5
1998	$41.1
1999	$34.7
2000	$66.4
2001	$135.5
2002	$111.7
2003	$207.4
2004	$327.7
2005	$429.5
2006	$394.6
2007	$486.0
2008	$450.0
2009	$188.8

Source: NYSDEC 1994-2009.

The combination of generally rising natural gas production and increasing average wellhead prices for much of the 2000s resulted in a substantial increase in the market value of New York State's natural gas production in the 2000s compared to the 1990s. The peak value of $486 million in 2007 was approximately 12 times larger than the average value for the years 1994 to 1999 inclusive (i.e., $41.51 million). However, between 2008 and 2009 the combination of a 10.7% decline in natural gas production and a 52.5% decline in the average wellhead price of natural gas resulted in a 58% decline in the market value of New York State's natural gas production.

Region A

Table 2.20 presents employment, by industry, within Tioga, Broome, and Chemung Counties, and for Region A. The largest employment sector in Region A is the educational, health, and social services sector, with approximately 28.7% of total employment in Region A (USCB 2009a). Manufacturing was the next largest employment sector, accounting for approximately 14.6% of total employment within the region. The economic center for Broome and Tioga Counties is the tri-city area of Binghamton, Endicott, and Johnson City, within the Binghamton Metropolitan Statistical Area (MSA). For Chemung County, the economic center is the city of Elmira.

Table 2.20 - Region A: Area Employment by Industry, 2009 (New August 2011)

	Region A		**Broome County**		**Chemung County**		**Tioga County**	
Sector	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**
Agriculture, forestry, fishing, hunting, and mining	1,464	1.0	558	0.6	335	0.9	571	2.3
Construction	8,572	5.6	4,846	5.3	2,054	5.4	1,672	6.8
Manufacturing	22,522	14.6	11,957	13.1	6,030	15.8	4,535	18.5
Wholesale trade	4,749	3.1	3,123	3.4	959	2.5	667	2.7
Retail trade	18,358	11.9	10,721	11.8	4,599	12.1	3,038	12.4
Transportation and warehousing, utilities	5,808	3.8	3,840	4.2	1,228	3.2	740	3.0
Information	3,096	2.0	2,016	2.2	706	1.9	374	1.5
Finance, insurance, real estate, and renting/leasing	7,554	4.9	5,022	5.5	1,719	4.5	813	3.3
Professional, scientific, management, administrative, and waste management services	11,847	7.7	7,140	7.8	2,575	6.8	2,132	8.7
Educational, health, and social services	44,084	28.7	26,764	29.3	10,869	28.5	6,451	26.4

Sector	Region A		Broome County		Chemung County		Tioga County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Arts, entertainment, recreation, accommodation, and food services	11,723	7.6	7,198	7.9	2,928	7.7	1,597	6.5
Other services (except public administration)	6,620	4.3	3,898	4.3	1,786	4.7	936	3.8
Public administration	7,435	4.8	4,154	4.6	2,348	6.2	933	3.8
Total	153,832		91,237		38,136		24,459	

Source: USCB 2009a.

Table 2.21 presents total and average wages across all industries for Region A. The average wages for persons employed across all industries in Region A was $37,875 in 2009.

Table 2.21 - Region A: Wages by Industry, 2009 (New August 2011)

	2009	
	Total Wages ($ millions)	**Average Wages**
Region A		
Total, all industries	$5,435.03	$37,875
Broome County		
Total, all industries	$3,390.12	$36,802
Chemung County		
Total, all industries	$1,379.61	$36,979
Tioga County		
Total, all industries	$665.30	$47,268

Source: NYSDOL 2009a, 2010b.

The total labor force for Region A is approximately 162,000 workers, of which 60% are in Broome County, 25% are in Chemung County, and 15% are in Tioga County. The annual average unemployment rate in Region A in 2010 was consistent with the overall state average unemployment rate of approximately 8.6% (Table 2.22). The rate of unemployment was slightly higher in Broome County than in Chemung or Tioga Counties. Overall, the size of the labor force has declined between 2000 and 2010 across the region, while the unemployment rate has generally doubled.

Table 2.22 - Region A: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Region A		
Total labor force	167,700	162,000
Employed workers	161,400	148,000
Unemployed workers	6,300	14,000
Unemployment rate (%)	3.8	8.6
Broome County		
Total labor force	98,300	95,700
Employed workers	94,800	87,200
Unemployed workers	3,600	8,500
Unemployment rate (%)	3.6	8.9
Chemung County		
Total labor force	42,800	40,700
Employed workers	41,000	37,300
Unemployed workers	1,800	3,400
Unemployment rate (%)	4.3	8.4
Tioga County		
Total labor force	26,600	25,600
Employed workers	25,600	23,500
Unemployed workers	900	2,100
Unemployment rate (%)	3.4	8.2

Source: NYSDOL 2010a.

Table 2.23 presents per capita income for Region A. Per capita income rose approximately 26.8% between 1999 and 2009. The percentage of individuals living below the poverty level in Region A increased from 12.2% in 1999 to 14.4% in 2009. During the same period, individuals living below the poverty level in New York State as a whole decreased from 14.6% to 13.9% (USCB 2000a, 2009b).

Table 2.23 - Region A: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region A		
Per capita income	$18,854	$23,912
% Below the poverty level[1]	12.2	14.4
Broome County		
Per capita income	$19,168	$24,432
% Below the poverty level[1]	12.8	15.0
Chemung County		
Per capita income	$18,264	$22,691
% Below the poverty level[1]	13.0	15.8
Tioga County		
Per capita income	$18,673	$24,034
% Below the poverty level[1]	8.4	10.0

Source: USCB 2000a, 2009b.

1 If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in the Binghamton MSA, which includes Broome and Tioga Counties are United Health Services, (3,300 employees); Lockheed Martin, (3,000 employees); Broome County (2,500 employees); the State University of New York Binghamton University (2,300 employees); and Lourdes Hospital (2,300 employees) (BCIDA 2010). The largest employer in Chemung County is St. Joseph's Hospital (1,000-1,200 employees) (STC Planning 2009).

The Empire State Development Corporation has identified 16 industry clusters for the Southern Tier Region of the state, which encompasses Region A (Broome, Chemung, and Tioga Counties) as well as Chenango, Delaware, Schuyler, Steuben, and Tompkins Counties. The industry clusters that support the largest number of jobs are industrial machinery and services, travel and tourism, financial services, front office and producer services, and electronics and imaging.

Travel and tourism is a large industry for the Southern Tier Region (which includes Region A), ranking second in employment of the 16 industry clusters in the Southern Tier Region. Broome and Tioga Counties are part of the Susquehanna Heritage Area, and Chemung County considers itself the gateway to the Finger Lakes Region. Various attractions and natural areas are described in more detail in Section 2.3.12, Visual Resources, and Section 2.3.15, Community Character. The travel and tourism industry employs approximately 4,590 persons throughout Region A (NYSDOL 2009b), primarily in food service (2,000 workers) and accommodations (1,190 workers) (Table 2.24). In 2009, wages earned by persons employed in the travel and tourism sector were approximately $78.6 million, or about 1.5% of all wages earned in Region A (NYSDOL 2009b) (Table 2.25).

Table 2.24 - Region A: Employment in Travel and Tourism, 2009 (New August 2011)

Industry Group	**Region A**		**Broome County**		**Chemung County**		**Tioga County**	
	Number of Jobs	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**	**Number of Jobs**	**% of Total**
Accommodations	1,190	25.9	830	27.8	210	18.3	150	33.3
Culture, recreation, and amusements	530	11.5	320	10.7	100	8.7	110	24.4
Food service	2,000	43.6	1,340	44.8	530	46.1	130	28.9
Passenger transportation	540	11.8	330	11.0	210	18.3	0	-
Travel retail	330	7.2	170	5.7	100	8.7	60	13.3
Total	4,590		2,990		1,150		450	

Source: NYSDOL 2009b.

Table 2.25 - Region A: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	**Average Wages**
Region A	$78.6	$17,100
Broome County	$50.3	$16,800
Chemung County	$20.9	$18,100
Tioga County	$7.4	$16,100

Source: NYSDOL 2009b.

Agriculture is also an important industry within Region A. Table 2.26 provides agricultural statistics for Broome, Chemung, and Tioga Counties. Approximately 1,518 farms are located in Region A, encompassing 258,571 acres of land. The value of agricultural production in 2009 was $83.2 million dollars (USDA 2007). The principal source of farm income is dairy products, which account for 70% of the agricultural sales in Broome County, and 75% of the sales in Tioga County (USDA 2007).

Table 2.26 - Region A: Agricultural Data, 2007 (New August 2011)

	Region A	Broome County	Chemung County	Tioga County
Number of farms	1,518	580	373	565
Land in farms (acres)	258,571	86,613	65,124	106,834
Average size of farm (acres)	170	149	175	189
Market value of Products Sold ($ millions)	83.2	29.9	16.6	36.7
Principal operator by primary occupation				
Farming	681	252	183	246
Other	837	328	190	319
Hired farm labor	971	340	238	393
Land in state-designated agricultural districts	278,935	153,233	41,966	83,736

Source: USDA 2007; NYSDAM 2011.

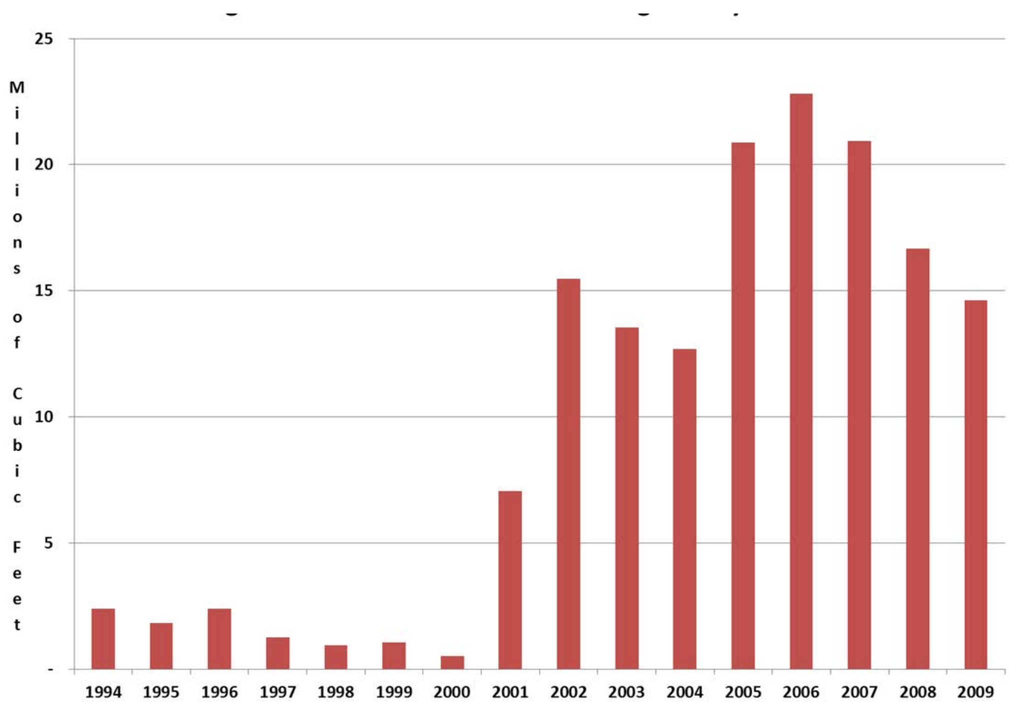
Approximately 125 persons are employed in the oil and gas industry in Region A, or about 34.5% of persons working in the oil and gas industry in New York State (NYSDOL 2009a, 2010b). Workers are primarily employed in Chemung County, as the data on oil and gas industry employment in Broome and Tioga Counties is so low as to not be reported due to business confidentiality reasons.

The oil and gas industry was a marginal contributor to total wages in Region A in 2009. Total wages for persons employed in the oil and gas industry in Chemung County were $12.5 million, or about 0.2% of total wages across all industries (NYSDOL 2009a, 2010b). The average annual wage for workers employed in the oil and gas sector in Chemung County was $99,600 in 2009.

In the 1990s, Region A was a minor contributor to New York State's natural gas production. However, starting in 2001, Region A experienced a substantial increase in its gas production, reaching a peak in 2006 before declining in each of the following three years (Figure 2.5).

Table 2.27 shows the number of active natural gas wells operating in Region A from 1994 to 2009. As shown on the table, the number of active wells in Region A has been steadily increasing since 1995.

Figure 2.5 - Region A: Natural Gas Production, 1994 to 2009 (New August 2011)



Source: NYSDEC 1994-2009.

Table 2.27 - Region A: Number of Active Natural Gas Wells, 1994-2009 (New August 2011)

Year	No. of Gas Wells
1994	15
1995	12
1996	15
1997	16
1998	17
1999	20
2000	19
2001	25
2002	29
2003	30
2004	36
2005	38
2006	37
2007	40
2008	41
2009	46

Source: NYSDEC 1994-2009.

In 2009, the average annual output per well in Region A was 317.9 MMcf of natural gas. The average production per well in Region A was greater (by a factor of 47) than the statewide average of 6.8 MMcf (NYSDEC 2009).

Table 2.28 shows the production of natural gas and the number of active wells, by town, within each county in Region A for 2009. As shown in the table, Chemung County accounted for nearly all of the natural gas production and active wells in Region A. There were no active natural gas wells in Broome County in 2009.

Table 2.28 – Natural Gas Production and Active Wells by Town within each County in Region A, 2009 (New August 2011)

Location	Natural Gas Production (Mcf)	Number of Active Gas Wells
Region A	**14,623,232**	**46**
Chemung County	13,890,161	45
Baldwin	327,738	1
Big Flats	2,095,184	4
Catlin	1,441,322	9
Elmira City	2,685	1
Erin	4,037,072	6
Horseheads	4,910	0
Southport	1,752,131	5
Van Etten	3,048,850	12
Veteran	1,180,269	7
Tioga County	733,071	1
Spencer	733,071	1

Source: NYSDEC 2009.

Region B

Table 2.29 presents employment, by industry, within Sullivan, Delaware, and Otsego Counties (Region B). The largest employment sectors are educational, health, and social services (30.1% of workers); retail trade (11.6%) arts, entertainment, recreation, accommodation, and food services (10.1%). This region also has a comparatively high number of employment in the agriculture, forestry, fishing, hunting, and mining sector (2.9%), particularly Delaware County (5.2%), compared to New York State as a whole (0.6%) (USCB 2009a).

Table 2.29 - Region B: Area Employment, by Industry, 2009 (New August 2011)

Industry Sector	Region B		Sullivan County		Delaware County		Otsego County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	2,498	2.9	591	1.7	1,102	5.2	805	2.7
Construction	7,276	8.5	3,178	9.2	2,051	9.7	2,047	6.8
Manufacturing	6,442	7.5	1,504	4.4	2,565	12.2	2,373	7.9
Wholesale Trade	2,134	2.5	924	2.7	432	2.0	778	2.6
Retail Trade	9,900	11.6	3,740	10.9	2,362	11.2	3,798	12.6
Transportation and warehousing, utilities	3,626	4.3	1,710	5.0	897	4.2	1,019	3.4
Information	1,493	1.7	696	2.0	323	1.5	474	1.6
Finance, insurance, real estate, and renting/leasing	4,373	5.1	2,034	5.9	737	3.5	1,602	5.3
Professional, scientific, management, administrative, and waste management services	4,618	5.4	2,006	5.8	1,113	5.3	1,499	5.0
Educational, health, and social services	25,788	30.1	10,368	30.1	5,564	26.4	9,856	32.8
Arts, entertainment, recreation, accommodation, and food services	8,630	10.1	3,494	10.1	1,845	8.7	3,291	11.0
Other services (except public administration)	4,248	5.0	1,818	5.3	1,069	5.1	1,361	4.5
Public administration	4,571	5.3	2,377	6.9	1,051	5.0	1,143	3.8
Total	**85,597**		**34,440**		**21,111**		**30,046**	

Source: USCB 2009a.

Table 2.30 presents total and average wages across all industries for Region B. The average wages for persons employed across all industries in Region B was $35,190 in 2009.

Table 2.30 - Region B: Wages, by Industry, 2009 (New August 2011)

	2009	
	Total Wages (millions)	**Average Wages**
Region B		
Total, all industries	$2,266.66	$35,190
Delaware County		
Total, all industries	$544.78	$34,655
Chemung County		
Total, all industries	$830.49	$35,310
Tioga County		
Total, all industries	$891.39	$35,412

Source: NYSDOL 2000ba, 2010b.

The total labor force for Region B is approximately 88,500 workers, of which 40% are in Sullivan County, 35% are in Otsego County, and 25% are in Delaware County. As shown in Table 2.31, the 2010 annual average unemployment rate in Region B was approximately 8.5%, similar to New York State as a whole. Among the counties that comprise Region B, Sullivan County had the highest average unemployment rate, approximately 9.2% (NYSDOL 2010a).

Table 2.31 - Region B: Labor Force Statistics, 2000 and 2010 ((New August 2011))

	2000	**2010**	**Percent Change**
Region B			
Total labor force	85,200	88,500	3.9
Employed workers	81,500	81,000	-0.6
Unemployed workers	3,600	7,500	108.3
Unemployment rate	4.2	8.5	102.3
Delaware County			
Total labor force	22,200	22,000	-0.9
Employed workers	21,300	20,100	-5.6
Unemployed workers	900	1,900	111.1
Unemployment rate (%)	4.2	8.7	107.1
Otsego County			
Labor force	29,800	31,500	5.7
Employed workers	28,500	29,100	2.1
Unemployed workers	1,300	2,400	84.6
Unemployment rate (%)	4.2	7.7	83.3
Sullivan County			
Labor force	33,200	35,000	5.4
Employed workers	31,700	31,800	0.3
Unemployed workers	1,400	3,200	128.6
Unemployment rate (%)	4.3	9.2	114.0

Source: NYSDOL 2010a.

Table 2.32 presents per capita income data for Region B. From 1999 to 2009, per capita income across the region increased by 27.9%. Individuals living below the poverty level in Region B increased from 14.9% in 1999 to 15.0% in 2009 (USCB 2000a, 2009b).

Table 2.32 - Region B: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region B		
Per capita income	$17,790	$22,750
% Below the poverty level[1]	14.9	15.0
Delaware County		
Per capita income	$17,357	$22,199
% Below the poverty level[1]	12.9	15.1
Otsego County		
Per capita income	$16,806	$22,255
% Below the poverty level[1]	14.9	15.2
Sullivan County		
Per capita income	$18,892	$23,491
% Below the poverty level[1]	16.3	14.7

Source: U.S. Census 2000a, 2009b.

[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in Delaware and Otsego Counties are: Bassett Healthcare (3,200+ employees), Amphenol Corporation (1,400 employees), State University of New York College Oneonta (1,181 employees); New York Central Mutual Fire Insurance Company (1,000 employees) and A.O. Fox Hospital (1,000 employees) (Bassett Healthcare 2011; Delaware County Economic Development 2010; Otsego County 2010).

The counties within Region B are part of three economic development regions, as defined by the Empire State Development Corporation, including the Southern Tier Region (Delaware County), Mid-Hudson Region (Sullivan County), and Mohawk Valley Region (Otsego County). Ranked by employment, travel and tourism is the lead employment industry cluster for the Mid-Hudson Region, and the second largest employment industry cluster in the Southern Tier and Mohawk Valley Regions. The tourism industry is an important economic driver in Region B, particularly in Otsego and Sullivan Counties, with the Catskill Mountains, as well as popular destinations such as the Baseball Hall of Fame in the village of Cooperstown (Otsego County) and the Monticello Raceway in the village of Monticello (Sullivan County). Approximately 4,560 persons were employed in the travel and tourism sector in Region B in 2009, including accommodations (1,820 jobs), and culture, recreation, and amusements (960 jobs), food service (930 jobs), passenger transportation (250 jobs), and travel retail (600 jobs) (Table 2.33). In 2009 wages earned by persons employed in the travel and tourism sector was approximately $72.3 million, or about 3.4% of all wages earned in Region B (NYSDOL 2009b) (Table 2.34).

Table 2.33 - Region B: Travel and Tourism, by Industrial Group, 2009 (New August 2011)

Industry Group	Region B		Delaware County		Otsego County		Sullivan County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Accommodations	1,820	39.9%	150	11.7%	530	35.3%	1,140	64.0%
Culture, recreation, and amusements	960	21.1%	100	7.8%	500	33.3%	360	20.2%
Food service	930	20.4%	360	28.1%	360	24.0%	210	11.8%
Passenger transportation	250	5.5%	150	11.7%	60	4.0%	40	2.2%
Travel retail	600	13.2%	520	40.6%	50	3.3%	30	1.7%
Total	4,560		1,280		1,500		1,780	

Source: NYSDOL 2009b.

Table 2.34 - Region B: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wage
Region B	$72.3	$19,500
Delaware County	$6.5	$15,400
Otsego County	$28.6	$19,200
Sullivan County	$37.2	$20,900

Source: NYSDOL 2009b.

Agriculture also is an important industry within Region B. Table 2.35 provides agricultural statistics for Delaware, Otsego, and Sullivan Counties. Approximately 2,050 farms are located in Region B, encompassing 392,496 acres of land. The value of agricultural production in 2009 was $148.7 million dollars (USDA 2007). The principal sources of farm income in the region are dairy products (particularly in Otsego and Delaware Counties, where dairy products accounted for 70% and 62% of the agricultural sales in the county, respectively) and poultry and eggs (particularly in Sullivan County, where poultry and eggs accounted for 65% of the sales in the county) (USDA 2007).

Table 2.35 - Region B: Agricultural Data, 2007 (New August 2011)

	Region B	**Delaware County**	**Otsego County**	**Sullivan County**
Number of farms	2,050	747	980	323
Land in farms (acres)	392,496	165,572	176,481	50,443
Average size of farm (acres)	191	222	180	156
Market value of Products Sold ($ millions)	$148.7	$55.1	$51.4	$42.1
Principal operator by primary occupation				
Farming	1,139	437	538	164
Other	911	310	442	159
Hired farm labor	1,746	760	574	412
Land in state designated agricultural districts	588,443	237,385	189,291	161,767

Source: USDA 2007; NYSDAM 2011.

Currently, there are no producing natural gas wells in Region B, although some exploratory well activity occurred in 2007 and 2009.

Region C

Table 2.36 presents employment by industry within Chautauqua and Cattaraugus Counties, and for Region C. The largest employment sectors in Region C are education, health, and social services sector (26.7% of total employment), manufacturing (16.5% of total employment), and retail trade (11.6%). The agriculture, forestry, fishing, hunting, and mining sector accounted for about 2.9% of total employment in the region, which is relatively high compared to New York State as a whole, which had 0.6% of its workforce employed in this sector (USCB 2009a).

Table 2.36 - Region C: Area Employment by Industry, 2009 (New August 2011)

Sector	Region C		Cattaraugus County		Chautauqua County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Agriculture, forestry, fishing, hunting, and mining	2,813	2.9	1,136	3.1	1,677	2.8
Construction	6,042	6.2	2,825	7.6	3,217	5.3
Manufacturing	16,194	16.6	5,752	15.5	10,442	17.2
Wholesale trade	2,620	2.3	879	2.4	1,741	2.9
Retail trade	11,392	11.7	4,432	11.9	6,960	11.5
Transportation and warehousing, utilities	4,116	4.2	1,398	3.7	2,718	4.4
Information	1,578	1.6	525	1.4	1,053	1.7
Finance, insurance, real estate, and renting/leasing	3,486	3.6	1,289	3.5	2,197	3.6
Professional, scientific, management, administrative, and waste management services	4,816	4.9	1,898	5.1	2,918	4.8
Educational, health, and social services	26,161	26.8	9,575	25.7	16,586	27.3
Arts, entertainment, recreation, accommodation, and food services	9,581	9.8	3,893	10.4	5,688	9.4
Other services (except public administration)	4,225	4.3	1,468	3.9	2,757	4.5
Public administration	4,960	5.1	2,150	5.8	2,810	4.6
	97,984		37220		60,764	

Source: USCB 2009a.

Table 2.37 presents total and average wages across all industries for Region C. The average wages for persons employed across all industries in Region C was $32,971 in 2009.

Table 2.37 - Region C: Wages, by Industry, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wages
Region C		
Total, all industries	$2,732.72	$32,971
Cattaraugus County		
Total, all industries	$1,046.92	$34,428
Chautauqua County		
Total, all industries	$1,685.80	$32,127

Source: NYSDOL 2009a, 2010b.

The total labor force for Region C is approximately 105,800 workers, of which 61% are in Chautauqua County, and 39% are in Cattaraugus County. As shown in Table 2.38, the 2010 annual average unemployment rate in Region C was approximately 8.9%. The size of the labor force decreased by 3.1% between 2000 and 2010 across the region, and the unemployment rate has generally doubled.

Table 2.38 - Region C: Labor Force Statistics, 2000 and 2010 (New August 2011)

	2000	2010
Region C		
Labor force	109,200	105,800
Employed workers	104,700	96,400
Unemployed workers	4,600	9,400
Unemployment rate (%)	4.2	8.9
Cattaraugus County		
Labor force	41,100	41,200
Employed workers	39,300	37,400
Unemployed workers	1,900	3,800
Unemployment rate (%)	4.5	9.2
Chautauqua County		
Labor force	68,100	64,600
Employed workers	65,400	59,000
Unemployed workers	2,700	5,600
Unemployment rate (%)	4.0	8.7

Source: NYSDOL 2010a.

Table 2.39 presents per capita income data for Region C. Per capita income in Region C rose approximately 26.2% between 1999 and 2009. The number of individuals living below the poverty level in Region C increased from 13.8% in 1999 to 16.1% in 2009.

Table 2.39 - Region C: Income Statistics, 1999 and 2009 (New August 2011)

	1999	2009
Region C		
Per capita income	$16,509	$20,830
% Below the poverty level[1]	13.8	16.1
Cattaraugus County		
Per capita income	$15,959	$20,508
% Below the poverty level[1]	13.7	15.7
Chautauqua County		
Per capita income	$16,840	$21,023
% Below the poverty level[1]	13.8	16.3

Source: U.S. Census 2000a, 2009b.

[1] If the total income for an individual falls below relevant poverty thresholds, updated annually relative to the Consumer Price Index for All Urban Consumers, then the individual is classified as being "below the poverty level."

The five largest employers in Region C are Dresser-Rand Company (3,300 employees); The Resource Center, Chautauqua County (1,748 employees); Chautauqua County (1,366 employees);

Cummins Engine, Chautauqua County (1,300 employees); and Cattaraugus County (1,180 employees) (Buffalo Business First 2011).

The Empire State Development Corporation has identified 16 industry clusters for the Western New York Region of the state, which encompasses Cattaraugus and Chautauqua Counties, as well as Erie (City of Buffalo), Niagara (City of Niagara Falls), and Allegany Counties. The industry clusters that support the largest number of jobs are front office and producer services, financial services, travel and tourism, industrial machinery and services, and distribution. Travel and tourism is the third largest industry cluster in terms of employment in the Western New York Region.

Tourism is a significant component of the economy in Region C. Cattaraugus County, known as the Enchanted Mountains Region, boasts abundant recreational opportunities that primarily revolve around its natural resources. Popular tourist destinations include Allegany State Park, the Amish Trail, Holiday Valley Ski Resort, Rock City Park, Griffis Sculpture Park, and the Seneca-Allegany Casino. Chautauqua County is also recognized for its natural resources and unique learning destinations associated with the Chautauqua Institute. Approximately 4,040 persons were employed in the travel and tourism sector in Region C in 2009, including accommodations (1,110 jobs); culture, recreation, and amusements (1,220 jobs); food service (1,210 jobs); passenger transportation (280 jobs); and travel retail (220 jobs) (Table 2.40). In 2009, wages earned by persons employed in the travel and tourism sector were approximately $77.5 million, or about 3.0% of all wages earned in Region C (NYSDOL 2009b) (Table 2.41).

Table 2.40 - Region C: Travel and Tourism, by Industrial Group, 2009 (New August 2011)

Industry Group	Region C		Cattaraugus County		Chautauqua County	
	Number of Jobs	% of Total	Number of Jobs	% of Total	Number of Jobs	% of Total
Accommodations	1,110	27.5%	180	10.5%	930	40.1%
Culture, Recreation and Amusements	1,220	30.2%	1,050	61.0%	170	7.3%
Food Service	1,210	30.0%	380	22.1%	830	35.8%
Passenger Transportation	280	6.9%	30	1.7%	250	10.8%
Travel Retail	220	5.4%	80	4.7%	140	6.0%
Total	**4,040**		**1,720**		**2,320**	

Source: NYSDOL 2009b.

Table 2.41 - Region C: Wages in Travel and Tourism, 2009 (New August 2011)

	2009	
	Total Wages (millions)	Average Wage
Region C	$77.5	$19,200
Cattaraugus County	$39.7	$23,300
Chautauqua County	$37.8	$16,300

Source: NYSDOL 2009b.

Agriculture is also an important industry within Region C. Table 2.42 provides agricultural statistics for Cattaraugus and Chautauqua Counties. Approximately 2,770 farms are located in Region C, encompassing 419,297 acres of land. The value of agricultural production in 2009 was $213.7 million dollars (USDA 2007). Dairy products account for approximately 68% of agricultural sales in Cattaraugus County. In Chautauqua County, the principal sources of farm income are grape and dairy products (USDA 2007). Grapes and grape products account for approximately 30% of agricultural sales in Chautauqua County, and dairy products account for approximately 51% of agricultural sales (USDA 2007).

Table 2.42 - Region C: Agricultural Data, 2007 (New August 2011)

	Region C	**Cattaraugus County**	**Chautauqua County**
Number of farms	2,770	1,112	1,658
Land in farms (acres)	419,297	183,439	235,858
Average size of farm (acres)	151	163	142
Market value of Products Sold ($ millions)	$213.7	$75.2	$138.6
Principal operator by primary occupation			
Farming	1,437	550	887
Other	1,343	572	771
Hired farm labor	4,341	994	3,347
Land in state-designated agricultural districts	631,686	239,641	392,045

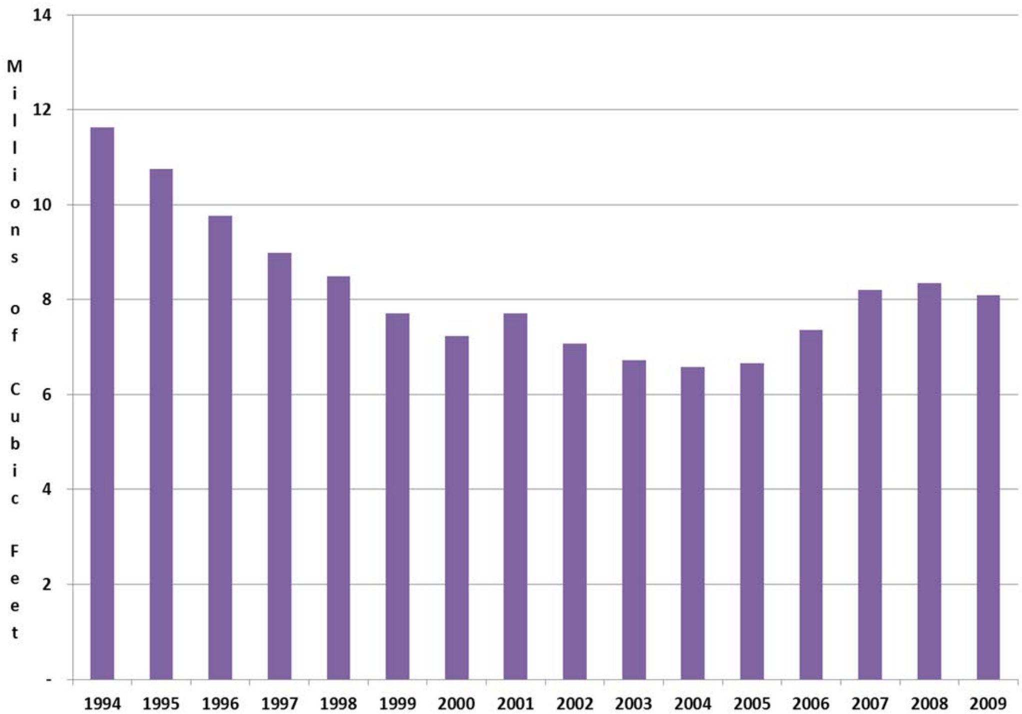
Source: USDA 2007; NYSDAM 2011.

Approximately 157 persons are employed in the oil and gas industry in Region C, or approximately 43.4% of all persons working in the oil and gas industry in New York State in 2009 (NYSDOL 2009a, 2010b).

The oil and gas industry was a marginal contributor to total wages in Region C in 2009. The total wages for persons employed in the oil and gas industry in the region were $10.8 million, or about 0.4% of the total wages across all industries (NYSDOL 2009a). The average annual wages for workers employed in the oil and gas sector varied greatly between the counties in Region C. The average annual wage for oil and gas workers in Cattaraugus County was $44,978 in 2009, whereas the average annual wage for oil and gas workers in Chautauqua County was $76,970 during the same time period (NYSDOL 2009a).

Natural gas production in Region C is shown on Figure 2.6. In the mid-1990s, Region C produced nearly 12 MMcf of natural gas per year. Production has declined from that level over the last 15 years, and the region is now producing slightly more than 8 MMcf of natural gas per year.

Figure 2.6 - Region C: Natural Gas Production, 1994-2009 (New August 2011)



Source: NYSDEC 1994-2009.

The total number of active natural gas wells in Region C over the period 1994 to 2009 is shown on Table 2.43. As shown in the table, the number of active natural gas wells in Region C has increased by nearly 400 wells since 1994, to a total of 3,917 wells.

Table 2.43 - Number of Active Natural Gas Wells in Region C, 1994-2009 (New August 2011)

Year	No. of Gas Wells
1994	3,523
1995	3,759
1996	3,512
1997	3,427
1998	3,585
1999	3,590
2000	3,545
2001	3,579
2002	3,350
2003	3,470
2004	3,645
2005	3,629
2006	3,740
2007	3,935
2008	3,984
2009	3,917

Source: NYSDEC 1994-2009.

In 2009 the average annual output per well in Region C was only 2.1 MMcf of natural gas. Production per well was significantly less than the average annual output per well in Region A (317.9 MMcf) or the statewide average per well (6.8 MMcf) (NYSDEC 2009). Because of this low productivity per well, Region C is currently a minor contributor to New York State's natural gas production, even though it accounts for the largest number of active wells in the state (NYSDEC 2009).

Table 2.44 shows the production of natural gas and the number of active wells, by town, within each county in Region C in 2009. As shown in the table, in 2009 there were 530 active gas wells in Cattaraugus County and 3,387 active gas wells in Chautauqua County (NYDEC 2009).

Table 2.44 - Natural Gas Production and the Number of Active Gas Wells by Town within each County in Region C, 2009 (New August 2011)

Location	**Natural Gas Production (Mcf)**	**Number of Active Gas Wells**
Region C	**14,623,232**	**46**
Cattaraugus County	1,615,243	530
Allegany	255,057	6
Ashford	10,416	11
Carrollton	89,633	3
Conewango	154,745	76
Dayton	113,159	59
East Otto	96,897	15
Ellicottville	737	3
Farmersville	214	2
Freedom	3,845	4
Leon	249,247	88
Machias	100	1
Napoli	1,187	2
New Albion	7,220	9
Olean	7,163	5
Otto	69,647	70
Perrysburg	343,006	42
Persia	99,100	43
Randolph	72,434	72
South Valley	892	2
Yorkshire	40,544	17
Chautauqua County	6,473,408	3,387
Arkwright	106,655	122
Busti	321,152	121

Location	Natural Gas Production (Mcf)	Number of Active Gas Wells
Carroll	181,427	70
Charlotte	230,836	127
Chautauqua	469,915	314
Cherry Creek	179,037	123
Clymer	159,828	101
Dunkirk	69,003	36
Dunkirk City	10,169	6
Ellery	180,187	82
Ellicott	204,129	66
Ellington	264,581	180
French Creek	26,003	40
Gerry	437,202	152
Hanover	450,439	152
Harmony	231,897	116
Jamestown	4,183	3
Kiantone	425,027	84
Mina	53,986	71
North Harmony	352,930	159
Poland	554,983	159
Pomfret	189,905	174
Portland	235,705	149
Ripley	185,487	182
Sheridan	142,294	86
Sherman	106,236	84
Stockton	169,836	118
Villanova	141,171	57
Westfield	389,205	253

Source: NYSDEC 2009.

2.3.11.2 Population

The following subsection discusses the past, current and projected population for New York State, and the local areas within each of the three regions (Region A, B and C).

New York State

New York State is the third most populous state in the country, with a 2010 population of approximately 19.38 million (USCB 2010) (see Table 2.45). The population density of the state is 410 persons per square mile. Nearly half of the population in the state is located within NYC (8.1 million persons). Subtracting out the population of NYC, the average population density of the rest of New York State is 237.3 persons per square mile. New York State's population has continually increased during the past 20 years, though the rate of growth was faster from 1990 to 2000 than it was from 2000 to 2010 (see Table 2.45).

Table 2.45 - New York State: Historical and Current Population, 1990, 2000, 2010 (New August 2011)

	Total Population	Percent Change	Average Annual Growth Rate	Average Population Density
2010	19,378,102	2.1%	0.2%	410.4
2000	18,976,457	5.5%	0.5%	401.9
1990	17,990,455	--	--	381.0

Source: USCB 1990a, 2000b, and 2010.

Table 2.46 shows the state's total 2010 population and presents population projections for 2015 to 2030. As shown, the population in New York State is projected to continue to grow through 2030. The state's population is projected to grow at an average annual rate of 0.2% between 2015 and 2030. By 2030, New York State's population is projected to reach 20,415,446 persons.

Table 2.46 - New York State: Projected Population, 2015 to 2030 (New August 2011)

Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
19,378,102	19,876,073	20,112,402	20,299,512	20,415,446	0.2%

Sources:
[a] USCB 2010.
[b] Cornell University 2009.

Region A

Table 2.47 provides the 1990, 2000 and 2010 population for Region A and for each of the three counties within this region. The population of Region A is 342,390 persons (USCB 2010), with an average population density of 209 persons per square mile. Since 1990, all three counties within Region A have lost population. Between 1990 and 2000, the region lost population at a rate of approximately 0.5% per year, and between 2000 and 2010, the region lost population at a rate of approximately 0.1% per year.

Table 2.47 - Region A: Historical and Current Population, 1990, 2000, 2010 (New August 2011)

Year	1990	2000	2010
Region A			
Total Population	359,692	343,390	340,555
Percent Change	--	-4.5%	-0.8%
Average Annual Growth Rate	--	-0.5%	-0.1%
Average Population Density	220.1	210.2	208.5
Broome County			
Population	212,160	200,536	200,600
Percent Change	--	-5.5%	<0.1%
Average Annual Growth Rate	--	-0.6%	< 0.1%
Average Population Density	300.2	283.7	283.8
Chemung County			
Population	95,195	91,070	88,830
Percent Change	--	-4.3%	-2.5%
Average Annual Growth Rate	--	-0.4%	-0.3%
Average Population Density	233.2	223.1	217.6
Tioga County			
Population	52,337	51,784	51,125
Percent Change	--	-1.1%	-1.3%
Average Annual Growth Rate	--	-0.1%	-0.1%
Average Population Density	100.9	99.8	98.6

Source: USCB 1990a, 2000b, and 2010.

The City of Binghamton has the largest population in the region, with a population in 2010 of 47,376; this is 13.9% of Region A's population as a whole. Other large population centers in the region include City of Elmira (29,200 persons), Village of Johnson City (15,174), and Village of Endicott (13,392 persons).

Region A's population has continually decreased during the past 20 years, though the rate of decline was faster from 1990 to 2000 than it was from 2000 to 2010 (see Table 2.47).

Table 2.48 shows Region A's total 2010 population and presents population projections for 2015 to 2030 (Cornell University 2009). As shown in Table 2.48, the population of Region A is projected to continue to decrease through 2030. The population of the Region is projected to decrease at an average annual rate of 0.7% between 2015 and 2030. By 2030, Region A's population is projected to be 279,675, which would be a decrease of 19% from the 2010 census population.

Table 2.48 - Region A: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
Broome	200,600	183,115	176,715	169,968	162,750	-0.7%
Chemung	88,830	83,282	80,643	77,773	74,614	-0.7%
Tioga	51,125	48,089	46,412	44,481	42,311	-0.8%
Region A Total	340,555	314,486	303,770	292,222	279,675	-0.7%

Sources: [a] USCB 2010; [b] Cornell University 2009.

Region B

Table 2.49 provides the 1990, 2000 and 2010 population for Region B and for each of the three counties within this region. The population of Region B is 187,786 persons (USCB 2010), with an average population density of 59.6 persons per square mile. The region has gained population over the last 20 years, primarily in Sullivan County. Between 1990 and 2000, the population grew at a rate of approximately 0.4% per year, and between 2000 and 2010, population increased at a rate of approximately 0.2% per year. Since 1990 the population of Region B has increased by 10,767, which is an increase of approximately 6.1%.

Table 2.49 - Region B: Historical and Current Population - 1990, 2000, 2010 (New August 2011)

	1990	2000	2010
Region B			
Population	177,019	183,697	187,786
Percent Change	--	3.8%	2.2%
Average Annual Growth Rate	--	0.4%	0.2%
Average Population Density	56.2	58.3	59.6
Delaware County			
Population	47,225	48,055	47,980
Percent Change	--	1.8%	-0.2%
Average Annual Growth Rate	--	0.2%	< 0.0%
Average Population Density	32.7	33.2	33.2
Otsego County			
Population	60,517	61,676	62,259
Percent Change	--	1.9%	1.0%
Average Annual Growth Rate	--	0.2%	0.1%
Average Population Density	60.4	61.5	62.1
Sullivan County			
Population	69,277	73,966	77,547
Percent Change	--	6.8%	4.8%
Average Annual Growth Rate	--	0.7%	.5%
Average Population Density	71.4	76.3	80.0

Source: USCB 1990a, 2000b, and 2010.

The two largest population centers in Region B are the City of Oneonta (13,901 persons) in Otsego County and the Village of Monticello (6,726 persons) in Sullivan County.

Region B's population has continually increased during the past 20 years, though the rate of growth has declined from the 1990 to 2000 period to the 2000 to 2010 period (see Table 2.49). Table 2.50 shows Region B's total 2010 population and presents population projections for 2015 to 2030 (Cornell University 2009). As shown in Table 2.50, the population in Region B overall is projected to decrease through 2030, although the population in Otsego County will increase slightly through 2025, then decline in 2030, and the population in Sullivan County will increase slightly between 2015 and 2030. By 2030, Region B's population is projected to be 183,031, which would be a decrease of 2.5% from the 2010 census population.

Table 2.50 - Region B: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	**Population 2010[a] (actual)**	**Population 2015[b] (projected)**	**Population 2020[b] (projected)**	**Population 2025[b] (projected)**	**Population 2030[b] (projected)**	**Average Annual Growth Rate 2015-2030**
Delaware	47,980	44,644	42,995	40,980	38,631	-0.9%
Otsego	62,259	63,820	64,344	64,597	64,508	0.1%
Sullivan	77,547	78,329	79,322	79,845	79,892	0.1%
Region B Total	**187,786**	**186,793**	**186,661**	**185,422**	**183,031**	**-0.1%**

Sources: [a] USCB 2010; [b] Cornell University 2009.

Region C

Table 2.51 provides the 1990, 2000 and 2010 population for Region C and for Cattaraugus and Chautauqua Counties. The population of Region C is 215,222 persons (USCB 2010), with an average population density of 90.7 persons per square mile. Between 2000 and 2010, the region lost population at an average annual rate of 0.4%. This rate was higher than the rate at which the region lost population between 1990 and 2000 (0.1% per year). Since 1990 the population of Region C has decreased by 10,907, or 4.8%.

Table 2.51 - Region C: Historical and Current Population - 1990, 2000, 2010 (New August 2011)

	1990	2000	2010
Region C			
Population	226,129	223,705	215,222
Percent Change	--	-1.1%	-3.8%
Average Annual Growth Rate	--	-0.1%	-0.4%
Average Population Density	95.3	94.3	90.7
Cattaraugus County			
Population	84,234	83,955	80,317
Percent Change	--	-0.3%	-4.3%
Average Annual Growth Rate	--	< 0.0%	-0.4
Average Population Density	64.3	64.1	61.3
Chautauqua County			
Population	141,895	139,750	134,905
Percent Change	--	-1.5%	-3.5%
Average Annual Growth Rate	--	-0.2%	-0.4%
Average Population Density	133.6	131.6	127.0

Source: USCB 1990a, 2000b, and 2010.

The largest population centers in Region C are the City of Jamestown (31,146 persons), City of Olean (14,452 persons), City of Dunkirk (12,563 persons), and Village of Fredonia (11,230 persons).

Region C's population has continually decreased during the past 20 years, though the rate of decline was faster from 2000 to 2010 than it was from 1990 to 2000. As shown in Table 2.52, the population of Region C is projected to continue to decrease through 2030. The population of Region C is projected to decrease at an average annual rate of 0.6% between 2015 and 2030. By 2030, Region C's population is projected to be 188,752 people, which would be a decrease of 12% from the 2010 census population.

Table 2.52 - Region C: Population Projections, 2015 to 2030 (New August 2011)

County/ Region	Population 2010[a] (actual)	Population 2015[b] (projected)	Population 2020[b] (projected)	Population 2025[b] (projected)	Population 2030[b] (projected)	Average Annual Growth Rate 2015-2030
Cattaraugus	80,317	77,870	75,651	73,048	70,075	-0.7%
Chautauqua	134,905	129,596	126,521	122,906	118,677	-0.6%
Region C Total	**215,222**	**207,466**	**202,172**	**195,954**	**188,752**	**-0.6%**

Source:
[a] USCB 2010.
[b] Cornell University 2009.

2.3.11.3 Housing

New York State

The total number of housing units in New York State in 2010 was 8.1 million. The total number of housing units has been growing over the past two decades; however, with the advent of the recent housing market crisis and recession, the rate of growth has slowed in the past few years. According to the U.S. Census Bureau, in 1990 there were a total of 7.2 million housing units in New York State. By 2000, the total number of housing units increased by 6.3% to approximately 7.7 million. Between 2000 and 2010, the total number of housing units increased by 5.6% (see Table 2.53) (USCB 1990b, 2000c, 2010).

Table 2.53 - New York State: Total Housing Units - 1990, 2000, 2010 (New August 2011)

Year	Total Housing Units	Percent Change
2010	8,108,103	5.6
2000	7,679,307	6.3
1990	7,226,891	--

Source: USCB 1990b, 2000c, and 2010.

Nearly half of all housing units in New York State are single-family units. In 2009 an estimated 3.7 million units, or 47.0% of all housing units in the state, were single-family units. Multi-family units, i.e., structures that have three or more units in them, accounted for 39.5% of the total housing units (see Table 2.54) (USCB 2009c).

Table 2.54 - New York State: Type of Housing Units, 2009[1] (New August 2011)

Type of Structure	Total Number of Units	% of Total
Single Family	3,735,364	47.0
Duplex	866,157	10.9
Multi-family	3,142,770	39.5
Mobile Home	202,773	2.6
Other	2,971	<0.1
Total	**7,905,035**	**100**

Source: USCB 2009c.

[1] Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* estimates is included herein.

Table 2.55 provides the number of sales and annual median sale price of single family homes sold in New York State over the past three years. The number of annual sales has declined over the past three years, while the median sales price has fluctuated. In 2008 the median sales price for single-family homes was $210,000. During the height of the housing market crisis in 2009, the median sales price fell to $195,000. By 2010 prices in the statewide housing market had recovered, and median sales prices rose to $215,000 (NYS Association of Realtors 2011a, 2011b). Although the statewide housing market statistics have improved over the last year, housing is intrinsically a local or regional market; many areas of New York State are still experiencing downward pressures on house prices.

Table 2.55 - New York State: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008	**2009**	**2010**
Number of Sales	80,521	78,327	74,718
Median Sale Price	$210,000	$195,000	$215,000

Source: NYS Association of Realtors 2011a, 2011b.

In 2010, New York State had approximately 3.9 million owner-occupied housing units and 3.4 million renter-occupied housing units (USCB 2010).

The homeowner vacancy rate was 1.9% and the rental vacancy rate was 5.5% (USCB 2010) (see Table 2.56).

Table 2.56 - New York State: Housing Characteristics, 2010 (New August 2011)

	Housing Units
Occupied	7,317,755
Owner Occupied	3,897,837
Renter Occupied	3,419,918
Vacant	790,348
For Rent	200,039
Rented, Not Occupied	12,786
For Sale Only	77,225
Sold, Not Occupied	21,027
For Seasonal, Recreational, or Occasional Use	289,301
All Other Vacant	189,970
Total	**8,108,103**
Homeowner Vacancy Rate	1.9%
Rental Vacancy Rate	5.5%

Source: USCB 2010.

Region A

According to the U.S. Census Bureau, the housing market in Region A has experienced little growth over the past two decades. As shown in Table 2.57, the region experienced an increase of 1.7% in the total number of housing units from 1990 to 2000, and a 2.1% increase from 2000 to 2010 (USCB 1990b, 2000c, 2010).

Table 2.57 - Region A: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	**Total Housing Units (2000)**	**Total Housing Units (2010)**	**Percent Change (1990-2000)**	**Percent Change (2000-2010)**
Region A	145,513	147,972	151,135	1.7%	2.1%
Broome County	87,969	88,817	90,563	1.0%	2.0%
Chemung County	37,290	37,745	38,369	1.2%	1.7%
Tioga County	20,254	21,410	22,203	5.7%	3.7%

Source: USCB 1990b, 2000c, 2010.

A majority of housing units in Region A are single-family units. In 2009 an estimated 96,956 units, or 65.0% of all housing units in the region, were single-family units. Multi-family units, i.e., structures that contained three or more housing units, accounted for 17.0% of the total housing units (see Table 2.58).

Table 2.58 - Region A: Total Housing Units by Type of Structure, 2009[1] (New August 2011)

	Number of Units	**% of Total**
Region A		
Single Family	96,956	65.0
Duplex	15,901	10.8
Multi-family	25,389	17.0
Mobile Home	10,756	7.2
Other	64	<0.1
	149,066	**100**
Broome County		
Single Family	56,225	63.1
Duplex	10,436	11.7
Multi-family	17,646	19.8
Mobile Home	4,795	5.4
Other	15	<0.1
	89,117	**100**

	Number of Units	% of Total
Chemung County		
Single Family	25,739	67.5
Duplex	4,291	11.3
Multi-family	5,749	15.1
Mobile Home	2,325	6.1
Other	12	<0.1
	38,116	**100**
Tioga County		
Single Family	14,992	68.7
Duplex	1,174	5.4
Multi-family	1,994	9.1
Mobile Home	3,636	16.7
Other	37	0.1
Total	**21,833**	**100**

Source: USCB 2009c.

1 Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* are provided herein.

Table 2.59 provides the number of sales and annual median sale price of single family homes sold in Region A over the past three years (New York State Association of Realtors 2011a, 2011b).

Table 2.59 - Region A: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		2009		2010	
	Number of Sales	Median Sale Price	Number of Sales	Median Sales Price	Number of Sales	Median Sales Price
Broome County	1,412	$109,438	1,287	$115,000	1,193	$106,000
Chemung County	629	$85,000	593	$86,000	638	$100,000
Tioga County	275	$136,170	304	$120,000	227	$122,500
Region A	2,316	NA	2,184	NA	2,058	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010, Region A had approximately 93,074 owner-occupied housing units and 44,905 renter-occupied housing units. The homeowner vacancy rate was 1.1%, and the rental vacancy rate was 7.8% (see Table 2.60) (USCB 2010).

Table 2.60 - Region A: Housing Characteristics, 2010 (New August 2011)

	Housing Units			
	Region A	Broome County	Chemung County	Tioga County
Occupied	137,979	82,167	35,462	20,350
Owner Occupied	93,074	53,260	24,011	15,803
Renter Occupied	44,905	28,907	11,451	4,547
Vacant	13,156	8,396	2,907	1,853
For Rent	3,824	2,522	917	385
Rented, Not Occupied	226	143	56	27
For Sale Only	1,516	956	377	183
Sold, Not Occupied	471	226	151	94
For Seasonal, Recreational, or Occasional Use	2,774	1,843	376	555
All Other Vacant	4,345	2,706	1,030	609
Total	**151,135**	**90,563**	**38,369**	**22,203**
Homeowner Vacancy Rate	1.1%	1.8%	1.5%	1.1%
Rental Vacancy Rate	7.8%	8.0%	7.4%	7.8%

Source: USCB 2010.

The *2010 Census of Population and Housing* identified 2,774 housing units in Region A that are considered seasonal, recreational, or occasional use. In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.61 lists the numbers of hotels/motels available in Region A that were registered with the I Love New York Tourism Agency. As of 2011 there were 40 hotels/motels with approximately 3,110 rooms in Region A.

Table 2.61 - Region A: Short-Term Accommodations (Hotels/Motels), 2011 (New August 2011)

	Total Hotels/Motels	Total Rooms
Broome County	27	2,202
Chemung County	9	676
Tioga County	4	232
Region A	**40**	**3,110**

Source: Official New York State Tourism Site (ILOVENY) 2011.

Region B

According to the U.S. Census Bureau, the rate of growth of the housing supply in Region B has increased since 1990. The total number of housing units in the region grew from 95,560 in 1990 to 102,163 in 2000, an increase of 6.9%. Between 2000 and 2010, the total number of housing units increased to 111,185, an increase of 8.8%. (see Table 2.62) (USCB 1990b, 2000c, 2010).

Table 2.62 - Region B: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	**Total Housing Units (2000)**	**Total Housing Units (2010)**	**Percent Change (1990-2000)**	**Percent Change (2000-2010)**
Delaware County	27,361	28,952	31,222	5.8%	7.8%
Otsego County	26,385	28,481	30,777	7.9%	8.1%
Sullivan County	41,814	44,730	49,186	7.0%	10.0%
Region B	**95,560**	**102,163**	**111,185**	**6.9%**	**8.8%**

Source: USCB 1990b, 2000c, 2010.

A majority of housing units in Region B are single-family units. In 2009 an estimated 76,883 units, or 70.7% of all housing units in the region, were single-family units. Mobile homes accounted for 12.7% of the total housing units (see Table 2.63).

Table 2.63 - Region B: Total Housing Units by Type of Structure 2009[1] (New August 2011)

	Number of Units	**% of Total**
Region B		
Single Family	76,883	70.7
Duplex	6,025	5.5
Multi-family	12,097	11.1
Mobile Home	13,731	12.7
Other	6	<0.1
Total	**108,742**	**100**
Delaware		
Single Family	21,876	73.6
Duplex	1,502	5.0
Multi-family	2,400	8.1
Mobile Home	3,949	13.3
Other	0	0
Total	**29,727**	**100**
Otsego		
Single Family	20,576	67.1
Duplex	1,791	5.9
Multi-family	3,868	12.6
Mobile Home	4,405	14.4

	Number of Units	% of Total
Other	6	<0.1
Total	**30,646**	**100**
Sullivan		
Single Family	34,431	71.2
Duplex	2,732	5.6
Multi-family	5,829	12.1
Mobile Home	5,377	11.1
Other	0	0
Total	**48,369**	**100**

Source: USCB 2009c.

[1] Data from the 2010 Census of Population and Housing on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 American Community Survey are provided herein.

As shown in Table 2.64, the housing market in Region B experienced a general decline in total sales and price in the single-family home market from 2008 to 2010. In the region as a whole, the number of single-family homes sold each year from 2008 to 2010 declined by 8.7%, from 785 homes in 2008 to 717 homes in 2010.

Median sale prices in the region experienced similar trends. From 2008 to 2010, the median sale price of single-family homes in Sullivan and Otsego Counties decreased by 16.4% and 8.8%, respectively. In contrast, the median sale price of homes in Delaware County remained relatively constant from 2008 to 2010 (see Table 2.64).

Table 2.64- Region B: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		**2009**		**2010**	
	Number of Sales	**Median Sale Price**	**Number of Sales**	**Median Sales Price**	**Number of Sales**	**Median Sales Price**
Delaware County	160	$109,250	171	$110,000	149	$110,000
Otsego County	309	$131,000	304	$126,523	319	$119,500
Sullivan County	316	$149,450	269	$125,000	249	$125,000
Region B	785	NA	744	NA	717	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010, Region B had approximately 52,860 owner-occupied housing units and 21,797 renter-occupied housing units. The homeowner vacancy rate was 2.6%, and the rental vacancy rate was 10.6% (USCB 2010).

There were 2,604 units for rent, 1,989 units for sale, and 27,240 units for seasonal, recreational, or occasional use in the area (see Table 2.65). The percentage of vacant seasonal, recreational, or occasional use units was very high, largely due to the region's proximity to the Catskill Mountains (USCB 2010).

Table 2.65 - Region B: Housing Characteristics, 2010 (New August 2011)

	Housing Units			
	Region B	**Delaware County**	**Otsego County**	**Sullivan County**
Occupied	74,657	19,898	24,620	30,139
Owner Occupied	52,860	14,768	17,885	20,207
Renter Occupied	21,797	5,130	6,735	9,932
Vacant	36,528	11,324	6,157	19,047
For Rent	2,604	565	615	1,424
Rented, Not Occupied	157	36	45	76
For Sale Only	1,989	446	514	1,029
Sold, Not Occupied	461	117	127	217
For Seasonal, Recreational, or Occasional Use	27,240	9,276	3,621	14,343
All Other Vacant	4,077	884	1,235	1,958
Total	**111,185**	**31,222**	**30,777**	**49,186**
Homeowner Vacancy Rate	2.6%	2.9%	2.8%	4.8%
Rental Vacancy Rate	10.6%	9.9%	8.3%	12.5%

Source: USCB 2010.

In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.66 lists the number of hotels/motels available in Region B that was registered with the I Love New York Tourism Agency. As of 2011 there were 78 hotels/motels with approximately 3,705 rooms in Region B (see Table 2.66).

Table 2.66 - Region B: Short-Term Accommodations (Hotels/Motels) (New August 2011)

	Total Hotels/Motels	**Total Rooms**
Delaware County	27	1,123
Otsego County	34	1,373
Sullivan County	17	1,209
Region B	**78**	**3,705**

Source: Official New York State Tourism Site (ILOVENY) 2011.

Region C

In 2010, Region C had a total of 108,031 housing units. The total number of housing units increased by 8.1% between 1990 and 2000, and by 3.2% between 2000 and 2010 (see Table 2.67) (USCB 1990b, 2000c, 2010). Approximately 62% of the housing units are located in Chautauqua County, and 38% are located in Cattaraugus County.

Table 2.67 - Region C: Total Housing Units - 1990, 2000, 2010 (New August 2011)

	Total Housing Units (1990)	Total Housing Units (2000)	Total Housing Units (2010)	Percent Change (1990-2000)	Percent Change (2000-2010)
Cattaraugus County	36,839	39,839	41,111	8.1%	3.2%
Chautauqua County	62,682	64,900	66,920	3.5%	3.1%
Region C	99,521	104,739	108,031	5.2%	3.1%

Source: USCB 1990b, 2000c, 2010.

Most of the housing units in Region C are single-family units. In 2009 an estimated 106,519 units, or 68.7% of all housing units in the region, were single-family units (see Table 2.68)

Table 2.68 - Region C: Total Housing Units by Type of Structure, 2009[1] (New August 2011)

	Number of Units	% of Total
Region C		
Single Family	73,183	68.7
Duplex	10,802	10.1
Multi-family	12,432	11.7
Mobile Home	10,090	9.5
Other	12	<0.1
Total	**106,519**	**100**
Cattaraugus		
Single Family	28,451	70.1
Duplex	2,850	7.0
Multi-family	3,797	9.3
Mobile Home	5,502	13.6
Other	12	<0.1
Total	**40,612**	**100**
Chautauqua		
Single Family	44,732	67.9
Duplex	7,952	12.0
Multi-family	8,635	13.1
Mobile Home	4,588	7.0
Other	0	0
Total	**65,907**	**100**

Source: USCB 2009c.

[1] Data from the *2010 Census of Population and Housing* on housing units by type of structure had not been released at the time of this report; therefore, estimated 2009 data from the 2005-2009 *American Community Survey* are provided herein.

As shown on Table 2.69, the market for single-family homes in Region C declined over the past three years. In the region as a whole, the number of single-family homes sold each year from 2008 to 2010 declined by 14.1%, from 1,492 homes in 2008 to 1,281 homes in 2010 (NYS Association of Realtors 2011a, 2011b).

Table 2.69 - Region C: Number of Sales and Annual Median Sale Price of Single-Family Homes Sold, 2008-2010 (New August 2011)

	2008		**2009**		**2010**	
	Number of Sales	**Median Sale Price**	**Number of Sales**	**Median Sales Price**	**Number of Sales**	**Median Sales Price**
Cattaraugus County	577	$69,000	501	$70,000	434	$73,000
Chautauqua County	915	$75,000	843	$74,521	847	$80,000
Region C	1,492	NA	1,344	NA	1,281	NA

Source: NYS Association of Realtors 2011a, 2011b.
NA = Not available.

In 2010 Region C had approximately 60,182 owner-occupied housing units and 26,325 renter-occupied housing units. The homeowner vacancy rate was 1.4%, and the rental vacancy rate was 9.0% (see Table 2.70) (USCB 2010).

Table 2.70 - Region C: Housing Characteristics, 2010 (New August 2011)

	Region C	**Cattaraugus County**	**Chautauqua County**
Occupied	86,507	32,263	54,244
Owner Occupied	60,182	23,306	36,876
Renter Occupied	26,325	8,857	17,368
Vacant	21,524	8,848	12,676
For Rent	2,624	748	1,876
Rented, Not Occupied	178	82	96
For Sale Only	1,278	483	795
Sold, Not Occupied	426	157	269
For Seasonal, Recreational, or Occasional Use	13,308	6,035	7,573
All Other Vacant	3,410	1,343	2,067
Total	108,031	41,111	66,920
Homeowner Vacancy Rate	1.4%	2.0%	2.1%
Rental Vacancy Rate	9.0%	7.6%	9.7%

Source: USCB 2010.

There were 2,624 units for rent, 1,278 units for sale, and 13,608 units for seasonal, recreational, or occasional use in the area. The percentage of vacant seasonal, recreational, or occasional use units was very high, largely due to the cottages around Lake Chautauqua, Chautauqua Institute, and other natural areas in these counties (USCB 2010).

In addition to the permanent housing discussed above, there are also numerous short-term accommodations including hotels, motels, inns, and campgrounds available in the area. Table 2.71 lists the number of hotels/motels available in Region C that was registered with the I Love New York Tourism Agency. As of 2011 there were 41 hotels/motels with approximately 1,987 rooms in Region C (see Table 2.71).

Table 2.71 - Region C: Short-Term Accommodations (Hotels/Motels) (New August 2011)

	Total Hotels/Motels	**Total Rooms**
Cattaraugus County	17	634
Chautauqua County	24	1,353
Region C	**41**	**1,987**

Source: Official New York State Tourism Site (ILOVENY) 2011.

2.3.11.4 Government Revenues and Expenditures

New York State

Table 2.72 lists the main sources of tax revenues for New York State. For fiscal year (FY) ending March 31, 2010, revenues collected in New York State totaled approximately $55 billion. Revenue from personal income taxes is the largest source of tax revenue for the state, accounting for approximately 63% of the total revenue (New York State Department of Taxation and Finance [NYSDTF] 2010a, 2010b).

Table 2.72 - New York State Revenues Collected for FY Ending March 31, 2010 (New August 2011)

	Personal Income Taxes	**Corporation and Business Taxes**	**Sales and Excise Taxes and User Fees**	**Property Transfers**	**Other Taxes and Fees**	**Total Revenues**
Total Revenues ($ billions)	$34.8	$6.6	$12.2	$1.4	$0.2	$55.2
Percent of Total	63.0	12.0	22.1	2.5	0.4	100.0

Source: NYSDTF 2010a, 2010b.
Totals may not equal sum of components due to rounding.

Currently, no specific state tax is levied on the extraction of natural gas in New York State; however, the state government receives revenues from the natural gas industry and from natural gas development primarily through income and sales taxes. The state assesses personal income tax on wages earned by workers in the industry, and income received by individuals as royalty payments and lease payments from natural gas operators. Further, the state also collects revenue from sales taxes receipts from the purchase of non-exempt materials and equipment needed to construct and operate natural gas wells. In some cases, the state may receive revenue from corporate and business taxes assessed on the corporate income of natural gas operators, though these taxes are subject to various exemptions and incentives that reduce the amount of revenue that the state is able to collect from the natural gas industry. In addition, New York State receives revenues from leases for oil and natural gas development on state lands. Lease revenues are acquired through delay rentals; bonus bids; royalties; and storage fees. Delay rentals are the annual fees that oil and natural gas developers pay to hold a leased property before development occurs. Bonus bids are additional fees above the delay rental fee for a specific tract. All bonus bids are subject to a sealed competitive bidding process. Once the gas well is developed, the delay rental payments are waived and the developer is assessed royalty fees of 12.5% of gross revenues. Storage fees are fees that are levied on the operators of underground natural gas storage facilities. A summary of the acreage and number of leases on state lands is provided in Table 2.73. Table 2.74 provides a summary of state revenues received between 2000 and 2010 from oil and gas lease payments.

Table 2.73 - New York State: Number of Leases and Acreage of State Land Leased for Oil and Natural Gas Development, 2010 (New August 2011)

County	Acreage of State Land Leased				Number of Leases			
	Rental	**Royalty**	**Storage**	**Total**	**Rental**	**Royalty**	**Storage**	**Total**
Allegany		126		126		1		1
Broome	512			512	1			1
Cattaraugus		62	9,981	10,043		2	8	10
Cayuga		62		62		4		4
Chautauqua		15,715		15,715		29		29
Chemung	730	667		1,397	3	10		13
Cortland	7,791			7,791	4			4
Erie		10	255	265		2	2	4
Ontario			55	55			1	1
Schuyler	2,416	10,019	1	12,436	1	6	1	8
Seneca		17		17		1		1
Steuben	685	5,859	1,620	8,164	1	8	2	11
Tioga	6,179			6,179	6			6
Tompkins	915			915	1			1
Total	**19,228**	**32,537**	**11,912**	**63,677**	**17**	**63**	**14**	**94**

Source: NYSDEC 2010.

Table 2.74 - 2000-2010 Leasing Revenue by Payment Type for New York State (New August 2011)

Year	Bonus Bids	Delay Rentals	Royalties	Storage Fees	Yearly Total
2000	-	$42,280	$75,327	$9,781	$127,388
2001	-	$118,732	$150,922	$178,128	$447,782
2002	-	$79,435	$96,620	$73,617	$249,672
2003	$4,583,239	$16,486	$609,821	$117,381	$5,326,927
2004	-	$130,746	$525,050	$109,986	$765,782
2005	-	$80,534	$3,235,206	$123,930	$3,439,670
2006	-	$75,305	$3,096,620	$125,007	$3,296,932
2007	$9,001,335	$166,868	$2,466,312	$133,298	$11,767,813
2008	-	$97,269	$1,866,519	$211,927	$2,175,715
2009	-	$96,136	$637,254	$50,960	$784,350
2010	$2,922	$96,377	$581,824	$65,010	$746,133

Source: NYSDEC 2010.

In New York State, local government entities have taxing authority for real property tax purposes.

However, the New York State Department of Taxation and Finance provides a uniform, statewide method of valuing natural-gas-producing properties for real property tax purposes. Valuations of natural-gas-producing properties are based on a "unit of production" value - a dollar amount per Mcf of gas produced. The total valuation is then equalized across four natural gas producing regions within the state, and then taxed at the local millage rate, similar to any other real property within the local jurisdiction.

Spending on community services is generally divided between the state and local governments (i.e., counties, municipalities, fire districts, and school districts). For public safety, New York State funds state troopers, counties fund county sheriffs, and municipalities commonly fund local police services. Emergency services such as fire protection/EMT are largely volunteer efforts in smaller towns, with some financial support received from smaller cities, suburban and rural towns, and villages. Major cities generally support their own fire departments, which generally have their own EMT operation.

Roadways are also supported by various levels of government. New York State provides funding for state and local highways, the operation of which is the responsibility of the NYSDOT as well as the New York State Thruway Authority. Counties finance county highways, while municipalities generally provide the funds to administer and maintain local roadways.

In regards to education, New York State financially supports the State University of New York (SUNY), a system of higher education institutions. Funding for K-12 education is generally provided by local school districts, which in turn receive revenues from a variety of sources, including federal aid, state aid, and real property taxes, among others.

Recreation services, including public parks, are another expenditure in which both state and local governments contribute. New York State provides funding to OPRHP, which operates recreational facilities at the state level, including the state park system. County governments generally provide funds for recreational facilities in towns and villages, while cities and larger suburban areas generally support their own recreational services.

Health, including Medicaid, is an expenditure that is largely carried by the state. Medicaid is a joint federal-state program. However, counties and major cities in New York State also contribute funds. Counties and local governments also have miscellaneous health care costs, including public health administration, public health services, mental health services, environmental services, and public health facilities, among others.

Expenditures for water and waste water treatment are generally made by counties and local municipalities.

Region A

Table 2.75 lists the main sources of public revenues for Region A. Revenues collected in Region A totaled approximately $736 million for the fiscal year ending December 31, 2009. The majority of revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 67.5% of total revenues in Region A (NYS Office of the State Comptroller 2010a).

Table 2.75 - Region A: Total Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Broome County	$169.4 (37.0)	$139.6 (30.4)	$309.0 (67.4)	$127.5 (27.8)	$436.5 (95.2)	$22.1 (4.8)	$458.6
Chemung County	$80.6 (42.0)	$47.3 (24.7)	$127.9 (66.7)	$54.8 (28.6)	$182.7 (95.3)	$9.1 (4.7)	$191.8
Tioga County	$39.4 (46.2)	$20.6 (24.1)	$60.0 (70.2)	$20.4 (23.9)	$80.4 (94.0)	$5.1 (6.0)	$85.5
Region A	$289.4 (39.4)	$207.5 (28.2)	$496.9 (67.5)	$202.7 (27.5)	$699.6 (95.1)	$36.3 (4.9)	$735.9

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.

2 Services include charges for services, charges to other governments, use and sale of property, and other local revenues.

3 Other revenues include proceeds of debt and all other sources of revenue.

4 Totals may not equal sum of components due to rounding.

As shown in Table 2.76, the total local tax revenue collected in Region A during the FY ending on December 31, 2009, was approximately $289.4 million. Of the total tax collected, 59.8% was derived from sales tax and distribution. Real property taxes, special assessments, and other real property tax items accounted for about 39.1% of the total local revenue (NYS Office of the State Comptroller 2010a).

Table 2.76 - Region A: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	**Special Assessments (% of total)**	**Other Real Property Tax Items[1] (% of total)**	**Sales Tax and Distribution (% of total)**	**Miscellaneous Use Taxes (% of total)**	**Other Non-Property Taxes[2] (% of total)**	**Total Tax Collection[3]**
Broome County	$59.1 (34.9)	$0 (0)	$4.0 (2.4)	$104.1 (61.4)	$1.5 (0.9)	$0.7 (0.4)	$169.4
Chemung County	$26.8 (33.3)	$0 (0)	$1.9 (2.4)	$51.2 (63.5)	$0.6 (0.7)	$0.1 (0.1)	$80.6
Tioga County	$19.2 (48.7)	$0 (0)	$2.2 (5.6)	$17.7 (44.9)	$0.1 (0.3)	$0.2 (0.5)	$39.4
Region A	$105.1 (36.3)	$0 (0)	$8.1 (2.8)	$173.0 (59.8)	$2.2 (0.7)	$1.0 (0.4)	$289.4

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

The production value (e.g., gas economic profile), state equalization rate, and millage rate for gas-producing properties in Region A are shown in Table 2.77. Broome, Chemung, and Tioga Counties are within the Medina Region 3, natural-gas-producing region designated by New York State. The final gas unit of production value for gas-producing properties within Medina Region 3 was $11.19 in 2010 (NYSDTF 2011). The overall full-value millage rates for Broome, Chemung, and Tioga Counties were 35.50, 34.30 and 30.80, respectively. These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.77 - Gas Economic Profile for Medina Region 3 (New August 2011)

	2010 Final Gas Unit of Production Value[a]	**Millage Rate[b] (2010)**
Broome County	$11.19	35.50
Chemung County	$11.19	34.30
Tioga County	$11.19	30.80

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the “overall full-value tax rate” and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.78 presents local government expenditures for Region A during the FY ending December 31, 2009. Social services combined to create the largest single expenditure in each of the counties of Region A. Approximately 28.7% of the counties' collective operating and capital budgets were spent on social services during the FY ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region A included general government (20.5%), employee benefits (15.3%), and health (9.9%). Public safety accounted for approximately 7.0% of total expenditures in Region A, including $15,299,556 for police and $118,376 for fire protection. No county in Region A spent any monies on emergency response. Broome and Chemung Counties did not financially support any fire protection services (NYS Office of the State Comptroller 2010a).

Table 2.78 - Region A: Expenditures for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Broome County		**Chemung County**		**Tioga County**		**Region A**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$91,817,010	20.4	$33,090,334	17.8	$21,682,356	27.0	$146,589,700	20.5
Education	$20,406,276	4.5	$4,412,651	2.4	$5,191,138	6.5	$30,010,065	4.2
Public Safety	$30,483,583	6.8	$12,944,032	7.0	$6,467,954	8.1	$49,895,569	7.0
Health	$39,151,049	8.7	$24,028,632	12.9	$7,398,260	9.2	$70,577,941	9.9
Transportation	$22,685,968	5.1	$14,625,859	7.9	$6,181,134	7.7	$43,492,961	6.1
Social Services	$122,931,621	27.4	$61,987,864	33.4	$20,346,458	25.4	$205,265,943	28.7
Economic Development	$6,005,330	1.3	$60,000	<0.1	$636,502	0.8	$6,701,832	0.9
Culture and Recreation	$10,186,350	2.3	$2,349,947	1.3	$232,827	0.3	$12,769,124	1.8
Community Services	$6,768,148	1.5	$2,978,999	1.6	$569,025	0.7	$10,316,172	1.4
Utilities	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Sanitation	$954,025	0.2	$5,780,216	3.1	$1,176,043	1.5	$7,910,284	1.1
Employee Benefits	$82,228,270	18.3	$17,926,465	9.6	$9,460,820	11.8	$109,615,555	15.3
Debt Service	$15,410,760	3.4	$5,620,336	3.0	$862,138	1.1	$21,893,234	3.1
Total Expenditures	$449,028,390	100.0	$185,805,335	100.0	$80,204,655	100.0	$715,038,380	100.0

Source: NYS Office of the State Comptroller 2010a.

Region B

Table 2.79 lists the main sources of county government revenues for Region B. Revenues collected in Region B totaled approximately $429.0 million for the fiscal year ending December 31, 2009. Most of the revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 65.6% of total revenues in Region B (NYS Office of the State Comptroller 2010a).

Table 2.79 - Region B: Total Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Delaware County	$43.1 (37.6)	$21.1 (18.4)	$64.2 (56.0)	$33.0 (28.8)	$97.1 (84.8)	$17.4 (15.2)	$114.5
Otsego County	$44.7 (41.6)	$30.7 (28.5)	$75.4 (70.1)	$25.2 (23.4)	$100.6 (93.5)	$7.0 (6.5)	$107.6
Sullivan County	$84.2 (40.7)	$57.5 (27.8)	$141.7 (68.5)	$44.2 (21.4)	$186.0 (89.9)	$20.9 (10.1)	$206.9
Region B	$172.0 (40.1)	$109.3 (25.5)	$281.3 (65.6)	$102.4 (23.9)	$383.7 (89.4)	$45.3 (10.6)	$429.0

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.
2 Services includes charges for services, charges to other governments, use and sale of property, and other local revenues.
3 Other revenues include proceeds of debt and all other sources of revenue.
4 Totals may not equal sum of components due to rounding.

As shown in Table 2.80, the total local tax revenue in Region B during the fiscal year ending on December 31, 2009, was approximately $173.7 million. Of the total tax collected, 49.2% was derived from taxes levied on real property, special assessments, and other real property tax items. Sales tax and distribution accounted for approximately 48.4% of the total (NYS Office of the State Comptroller 2010a).

Table 2.80 - Region B: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	Special Assessments (% of total)	Other Real Property Tax Items[1] (% of total)	Sales Tax and Distribution (% of total)	Miscellaneous Use Taxes (% of total)	Other Non-Property Taxes[2] (% of total)	Total Revenue
Delaware County	$23.4 (54.2)	$0 (0)	$1.7 (3.9)	$17.9 (41.4)	$0 (0)	$0.2 (0.5)	$43.2
Otsego County	$9.5 (20.5)	$1.1 (2.4)	$1.4 (3.0)	$33.1 (71.3)	$1.1 (2.4)	$0.2 (0.4)	$46.4
Sullivan County	$42.1 (50.1)	$0 (0)	$6.3 (7.5)	$33.1 (39.4)	$1.1 (1.3)	$1.5 (1.8)	$84.1
Region B	$75.0 (43.2)	$1.1 (0.6)	$9.4 (5.4)	$84.1 (48.4)	$2.2 (1.3)	$1.9 (1.1)	$173.7

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

Delaware, Otsego, and Sullivan Counties are within Medina Region 4, natural-gas-producing region designated by New York State. The final gas unit of production value for gas-producing properties within the Medina Region 4 was $11.19 in 2010; the 2011 tentative gas unit of production value is $11.32 (NYSDTF 2011). The 2010 overall full-value millage rates for Delaware, Otsego, and Sullivan Counties were 21.20, 19.60 and 26.20, respectively (see Table 2.81). These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.81 - Gas Economic Profile for Medina Region 4 and State Equalization Rates and Millage Rates for Region B (New August 2011)

	Final Gas Unit of Production Value (2010)[a]	Millage Rate[b] (2010)
Delaware County	$11.19	21.20
Otsego County	$11.19	19.60
Sullivan County	$11.19	26.20

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the “overall full-value tax rate” and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.82 presents local government expenditures for Region B during the FY ending December 31, 2009. Social services combined to create the largest single expenditure in each of the counties in Region B. Approximately 30% of the counties' collective operating and capital budgets were spent on social services during the FY ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region B included employee benefits (14.5%), general government (12.4%), and transportation (12.3%). Public safety accounted for approximately 7.7% of total expenditures in Region B, including $9,103,208 for police and $70,719 for fire protection. No county in Region B spent any monies on emergency response. Delaware and Otsego Counties did not financially support any fire protection services (NYS Office of the State Comptroller 2010a).

Table 2.82 - Region B: Expenditures for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Delaware County		**Otsego County**		**Sullivan County**		**Region B**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$8,960,337	9.7	$18,661,059	17.9	$20,991,003	10.7	$48,612,399	12.4
Education	$623,530	0.7	$2,546,555	2.4	$6,342,470	3.2	$9,512,555	2.4
Public Safety	$5,541,817	6.0	$6,882,871	6.6	$17,902,819	9.1	$30,327,507	7.7
Health	$8,405,703	9.1	$5,563,650	5.3	$29,995,278	15.3	$43,964,631	11.2
Transportation	$18,081,013	19.5	$11,588,286	11.1	$18,465,889	9.4	$48,135,188	12.3
Social Services	$28,776,564	31.1	$37,215,496	35.6	$51,657,658	26.4	$117,649,718	30.0
Economic Development	$610,060	0.7	$1,069,964	1.0	$2,390,941	1.2	$4,070,965	1.0
Culture and Recreation	$702,837	0.8	$277,033	0.3	$2,802,213	1.4	$3,782,083	1.0
Community Services	$3,172,734	3.4	$2,047,629	2.0	$1,087,185	0.6	$6,307,548	1.6
Utilities	$0	0.0	$0	0.0	$0	0.0	$0	0.0
Sanitation	$3,906,766	4.2	$1,065,180	1.0	$4,312,952	2.2	$9,284,898	2.4
Employee Benefits	$10,972,513	11.9	$15,976,297	15.3	$30,048,837	15.4	$56,997,647	14.5
Debt Service	$2,826,085	3.1	$1,606,314	1.5	$9,742,478	5.0	$14,174,877	3.6
Total Expenditures	$92,579,959	100.0	$104,500,334	100.0	$195,739,723	100.0	$392,820,016	100.0

Source: NYS Office of the State Comptroller 2010a.

Region C

Table 2.83 lists the main sources of county government revenues for Region C. Revenues collected in Region C totaled approximately $501.4 million for the fiscal year ending December 31, 2009. Most of the revenues were derived from local sources. Local revenue, including ad valorem (real and personal property) tax receipts and services, accounted for approximately 70.8% of total revenues in Region C (NYS Office of the State Comptroller 2010a).

Table 2.83 - Region C: Revenues for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Taxes[1] (% of total)	**Services[2] (% of total)**	**Subtotal Local Revenue (% of total)**	**State/ Federal Aid (% of total)**	**Subtotal Local// (% of total)**	**Other Sources[3] (% of total)**	**Total Revenue[4]**
Cattaraugus County	$78.1 (36.4)	$73.6 (34.3)	$151.7 (70.6)	$42.7 (19.9)	$194.4 (90.5)	$20.4 (9.5)	$214.8
Chautauqua County	$114.8 (40.1)	$88.5 (30.9)	$203.3 (70.9)	$65.0 (22.7)	$268.3 (93.6)	$18.3 (6.4)	$286.6
Region C	$192.9 (38.5)	$162.1 (32.3)	$355.0 (70.8)	$107.7 (21.5)	$462.7 (92.3)	$38.7 (7.7)	$501.4

Source: NYS Office of the State Comptroller 2010a.

1 Taxes include real property taxes and assessments, other real property tax items, sales and use taxes, and other non-property taxes.

2 Services include charges for services, charges to other governments, use and sale of property, and other local revenues.

3 Other revenues include proceeds of debt and all other sources of revenue.

4 Totals may not equal sum of components due to rounding

As shown in Table 2.84, the total local tax revenue in Region C during the fiscal year ending on December 31, 2009, was approximately $192.8 million. Of the total receipts, 53.2% was derived from taxes levied on real property, special assessments, and other real property tax items. Sales tax and distribution accounted for approximately 45.1% of the total (NYS Office of the State Comptroller 2010a).

Table 2.84 - Region C: Local Tax Revenue for FY Ending December 31, 2009 ($ millions) (New August 2011)

	Real Property Taxes (% of total)	Special Assessments (% of total)	Other Real Property Tax Items[1] (% of total)	Sales Tax and Distribution (% of total)	Miscellaneous Use Taxes (% of total)	Other Non-Property Taxes[2] (% of total)	Total Tax Collection[3]
Cattaraugus County	$42.0 (53.8%)	$0 (0%)	$2.6 (3.3%)	$33.1 (42.4%)	$0 (0%)	$0.3 (0.4%)	$78.0
Chautauqua County	$54.2 (47.2%)	$0 (0%)	$3.7 (3.2%)	$53.8 (46.9%)	$1.2 (1.0%)	$1.9 (1.7%)	$114.8
Region C	$96.2 (49.9%)	$0 (0%)	$6.3 (3.3%)	$86.9 (45.1%)	$1.2 (0.6%)	$2.2 (1.1%)	$192.8

Source: NYS Office of the State Comptroller 2010a.

1 Other real property tax items include STAR payments, payments in lieu of taxes, interest penalties, gain from sale of tax acquired property, and miscellaneous tax items.

2 Other non-property taxes include franchises, emergency telephone system surcharges, city income taxes, and other miscellaneous non-property taxes.

3 Totals may not equal sum of components due to rounding.

Cattaraugus and Chautauqua Counties are both split between Medina Region 2 and Medina Region 3, natural-gas-producing regions designated by New York State. The final gas unit of production value for Medina Region 2 and Medina Region 3 was $11.19 in 2010; the 2011 tentative gas unit of production value is $11.32 (NYSDTF 2011). The 2010 overall full-value millage rates for Cattaraugus and Chautauqua Counties were 35.50 and 32.10, respectively (see Table 2.85). These rates have already been equalized and include the rates of all taxing districts in the county, including county, town, village, school district, and other special district rates.

Table 2.85 - Gas Economic Profile for Medina Region 2 and State Equalization Rates and Millage Rates for Region C (New August 2011)

	Final Gas Unit of Production Value (2010)[a]	Millage Rate[b] (2010)
Cattaraugus County	$11.19	35.50
Chautauqua County	$11.19	32.10

Sources:

a NYSDTF 2011.

b NYS Office of the State Comptroller 2010b. Millage rates represent the “overall full-value tax rate” and include the rates of all taxing districts in the county, including county, town, village, school district, and special districts rates.

Table 2.86 presents local government expenditures for Region C during the fiscal year ending December 31, 2009. Social services combined to create the largest single expenditure in both Cattaraugus and Chautauqua Counties, and thus in Region C. Approximately 30% of the counties' collective operating and capital budgets were spent on social services during the fiscal year ending December 31, 2009. Expenditure categories within social services include social service administration, financial assistance, Medicaid, non-Medicaid medical assistance, housing assistance, employment services, youth services, public facilities, and miscellaneous social services. Other major expenditures in Region C included general government (19.7%), employee benefits (13.4%), and transportation (10.2%). Public safety accounted for approximately 7.2% of total expenditures in Region C, including $12,866,430 for police, $260,959 for fire protection, and $100,667 for emergency response (NYS Office of the State Comptroller 2010a).

Table 2.86 - Region C: Expenditures for FY Ending December 31, 2009 (New August 2011)

	Cattaraugus County		**Chautauqua County**		**Region B**	
	Total $	**% of Total**	**Total $**	**% of Total**	**Total $**	**% of Total**
General Government	$38,547,702	20.2	$51,753,045	19.4	$90,300,747	19.7
Education	$6,779,075	3.5	$10,119,356	3.8	$16,898,431	3.7
Public Safety	$13,349,284	7.0	$19,805,376	7.4	$33,154,660	7.2
Health	$23,233,153	12.2	$14,164,348	5.3	$37,397,501	8.2
Transportation	$20,346,282	10.7	$26,489,032	9.9	$46,835,314	10.2
Social Services	$49,828,802	26.1	$87,553,524	32.8	$137,382,326	30.0
Economic Development	$1,278,250	0.7	$3,395,624	1.3	$4,673,874	1.0
Culture and Recreation	$1,489,536	0.8	$694,416	0.3	$2,183,952	0.5
Community Services	$2,877,290	1.5	$3,752,921	1.4	$6,630,211	1.4
Utilities	$0	0.0	$21,402	<0.1	$21,402	<0.1
Sanitation	$2,004,345	1.0	$7,288,201	2.7	$9,292,546	2.0
Employee Benefits	$23,122,461	12.1	$38,268,359	14.4	$61,390,820	13.4
Debt Service	$8,144,509	4.3	$3,368,753	1.3	$11,513,262	2.5
Total Expenditures	**$191,000,689**	**100.0**	**$266,674,357**	**100.0**	**$457,675,046**	**100.0**

Source: NYS Office of the State Comptroller 2010a.

2.3.11.5 Environmental Justice

New York State

Nearly each county in New York State has census block groups that may be considered potential EJ areas. The term "environmental justice" refers to a Federal policy established by Executive Order 12898 (59 Federal Register [FR] 7629) under which each Federal agency identifies and addresses, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority or low-income populations. In response to EO 12898 the U.S. Environmental Protection Agency developed a definition of EJ as follows:

> *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. Fair treatment means that no group of people, including a racial, ethnic, or socioeconomic group, should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies.*

The Department's Commissioner Policy 29 (the Policy) on Environmental Justice and Permitting expands upon Executive Order 12898, defining a potential EJ area as a minority or low-income community that bears a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies.

The New York State Policy defines a minority population as a group of individuals that are identified or recognized as African-American, Asian American/Pacific Islander, American Indian, or Hispanic. A minority community exists where a census block group, or multiple census block groups, has a minority population equal to or greater than 51.1% in urban areas or 33.8% in rural areas. Rural and urban area classifications are established by the USCB. Urban area means all territory, population, and housing units located in urbanized areas and in places of 2,500 or more inhabitants outside of an urbanized area. An urbanized area is a continuously built-up area with a population of 50,000 or more. Rural area means territory, population, and housing units that are not classified as an urban area.

A low-income population is defined by the Policy as a group of individuals having an annual income that is less than the poverty threshold established by the USCB. A low-income community is a census block group, or area with multiple census block groups, having a low-income population equal to or greater than 23.59% of the total population for whom poverty status is determined.

The Policy applies to applications for major projects and major modifications for the permits authorized by the following sections of the Environmental Conservation Law:

- Titles 7 and 8 of Article 17, SPDES (implemented by 6 NYCRR Part 750 et seq.);
- Article 19, Air Pollution Control (implemented by 6 NYCRR Part 201 et seq.);
- Title 7 of Article 27, solid waste management (implemented by 6 NYCRR Part 360): including minor modifications involving any tonnage increases beyond the approved design capacity and minor modifications involving an increase in the amount of putrescible solid waste beyond the amount that has already been approved in the existing permit;
- Title 9 of Article 27, industrial hazardous waste management (implemented by 6 NYCRR Part 373); and
- Title 11 of Article 27, siting of industrial hazardous waste facilities (implemented by 6 NYCRR Part 361).

A Department permit applicant must conduct a preliminary screen to identify whether the proposed action is located in a potential EJ area. The applicant also must identify potential adverse environmental impacts within the area to be affected. The Department provides online mapping for each New York State county to assist applicants in identifying potential EJ areas. Census block data is utilized to identify these areas. The mapping referenced in this section was last updated in 2005.

The following provides a discussion of the minority and low-income populations in the state and in each of the representative regions for background information.

In 2010, the percent minority population in New York State was 34.25%. The Hispanic population was 17.6% in 2010; and the percent of persons living below poverty level in 2009 was 13.9%.

According to the *2010 Census of Population and Housing*, approximately 97.0% of residents of New York State identify themselves as being of a single race: 65.8% of the population of New York State self-identify as White; 15.9% as Black or African American; 0.6% as American Indian and Alaska Native; 7.3% as Asian; less than (<) 0.1% as Native Hawaiian and Other Pacific Island; and 7.4% as some other race (USCB 2010). The remaining 3.0% of the population self-identifies as two or more races (see Table 2.87).

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as Hispanic or Latino on the 2010 Census, regardless of race. In New York State, 17.6% of the population self-identifies as being Hispanic or Latino.

Table 2.87 presents a summary of the total population of New York State by the race/ethnicity categories defined by the USCB.

Table 2.87 - Racial and Ethnicity Characteristics for New York State (New August 2011)

Population Category	**Population**	**Percentage of Total 2010 Population**
Total 2010 Population	19,378,102	100.0%
White Only	12,740,940	65.8%
Black or African American Only	3,073,800	15.9%
American Indian and Alaska Native Only	106,906	0.6%
Asian Only	1,420,244	7.3%
Native Hawaiian and Other Pacific Islander Only	8,766	< 0.1%
Some Other Race Only	1,441,563	7.4%
Total Population of One Race	18,792,219	97.0%
Two or more races	585,849	3.0%
Hispanic or Latino	3,416,922	17.6

Source: USCB 2010.
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

Region A

In 2010, the combined percent minority for Region A was 10.51%. Chemung and Broome Counties had similar percentages of minority population, while Tioga County had a relatively low percentage (3.07% minority). Region A had a combined percent Hispanic population of 1.82%.

The counties which comprise Region A, both collectively and individually, are not considered minority communities.

The combined poverty level of Region A in 2009 was 14.4% in 2009, while Tioga County had a lower percentage (10.0%) than Broome and Chemung Counties. The poverty level for Region A is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping for each county identifies potential EJ areas at the census block group level. These maps were combined to illustrate potential EJ areas in Region A (Figure 2.7). The mapping indicates that some census blocks in Chemung County (towns of Elmira and Ashland); Tioga County (towns of Barton and Owego); and Broome County (towns of Vestal and Kirkwood) are potential EJ areas based on their minority and/or low-income populations.

According to the *2010 Census of Population and Housing*, approximately 97.6% of the individuals in Region A identify themselves as being of a single race: 89.5% of the population of Region A self-identifies as White; 4.6% as Black or African American; 0.2% as American Indian and Alaska Native; 2.5% as Asian; less than (<) 0.1% as Native Hawaiian and Other Pacific Island; and 0.8% as some other race (USCB 2010). The remaining 2.4% self-identifies as two or more races.

In Region A, 1.8% of the population self-identifies as being Hispanic or Latino. Table 2.88 presents a summary of the total population of Region A by the race/ethnicity categories defined by the USCB.

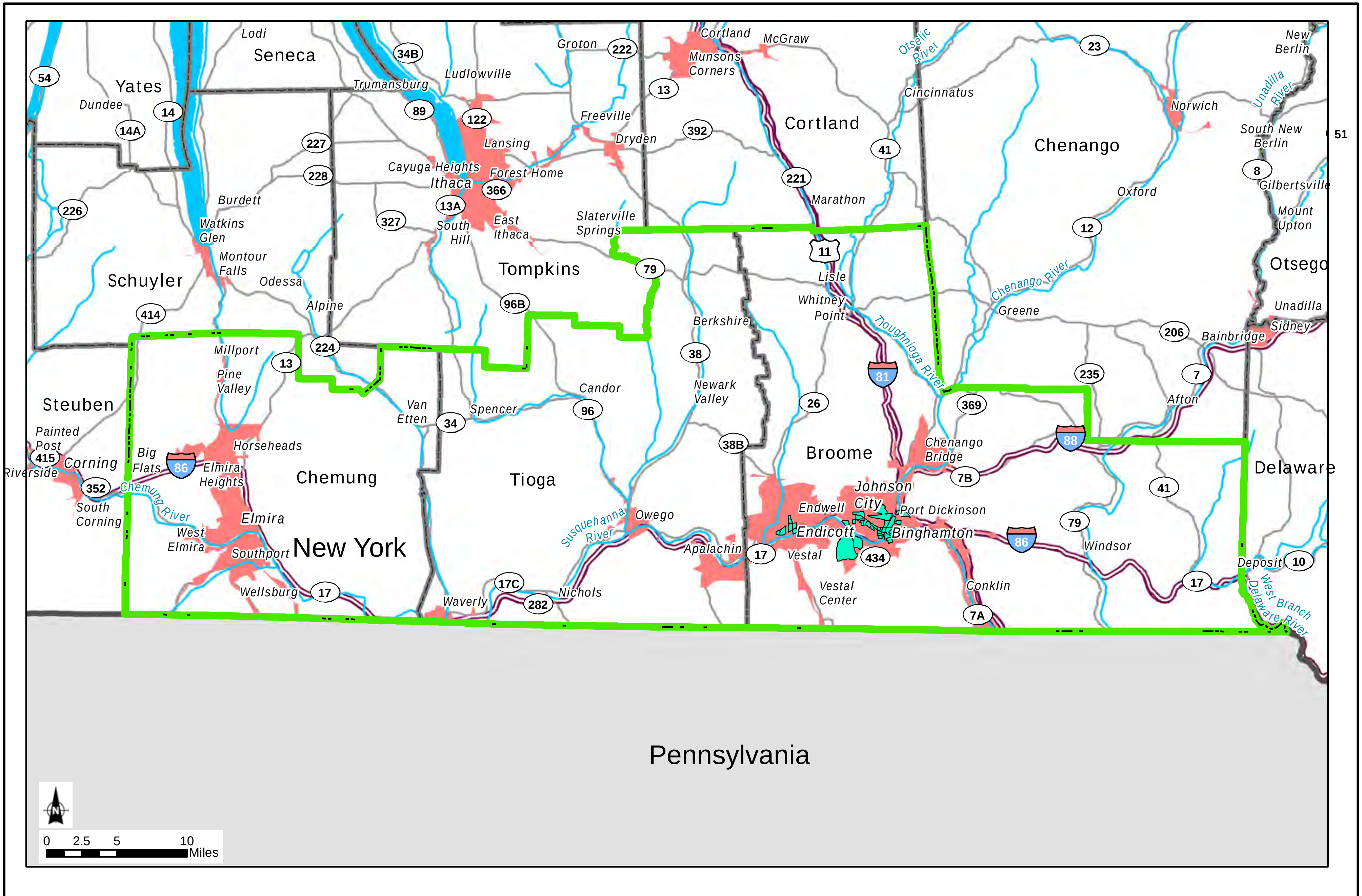


Figure 2.7: Potential Environmental Justice Areas for Region A

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.88 - Region A: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Broome County		
Total 2010 Population	200,600	100.0%
White Only	176,444	88.0%
Black or African American Only	9,614	4.8%
American Indian and Alaska Native Only	396	0.2%
Asian Only	7,065	3.5%
Native Hawaiian and Other Pacific Islander Only	82	<0.1%
Some Other Race Only	1,912	1.0%
Total Population of One Race	195,513	97.5%
Two or more races	5,087	2.5%
Hispanic or Latino	4,334	2.2%
Chemung County		
Total 2010 Population	88,830	100.0%
White Only	78,771	88.7%
Black or African American Only	5,828	6.6%
American Indian and Alaska Native Only	233	0.3%
Asian Only	1,057	1.2%
Native Hawaiian and Other Pacific Islander Only	20	< 0.1%
Some Other Race Only	539	0.6%
Total Population of One Race	86,448	97.4%
Two or more races	2,372	2.7%
Hispanic or Latino	1,436	1.6%
Tioga County		
Total 2010 Population	51,125	100.0%
White Only	49,556	96.9%
Black or African American Only	375	0.7%
American Indian and Alaska Native Only	86	0.2%
Asian Only	372	0.7%
Native Hawaiian and Other Pacific Islander Only	15	<0.1%
Some Other Race Only	146	0.3%
Total Population of One Race	50,550	98.9%
Two or more races	575	1.1%
Hispanic or Latino	412	0.8%
Region A Total		
Total 2010 Population	340,555	100.0%
White Only	304,771	89.5%
Black or African American Only	15,817	4.6%
American Indian and Alaska Native Only	715	0.2%
Asian Only	8,494	2.5%
Native Hawaiian and Other Pacific Islander Only	117	< 0.1%
Some Other Race Only	2,597	0.8%
Total Population of One Race	332,511	97.6%
Two or more races	8,034	2.4%
Hispanic or Latino	6,182	1.8%

Source: USCB 2010.
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing.*

Region B

Region B comprises three counties: Sullivan, Delaware, and Otsego Counties. The 2010 combined percent minority for Region B was 10.45%. Delaware and Otsego Counties had similar percentages of minority population, while Sullivan County had a relatively higher percentage (18.04% minority). Region B had a combined percent Hispanic population of 5.02%, with Sullivan County having a slightly higher percentage of Hispanic persons at approximately 9% of total population. The counties which comprise Region B are not considered minority communities. The combined poverty level of Region B was 15.0% in 2009. The poverty level for Region B is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping for each county identifies potential EJ areas at the census block group level. These maps were combined to illustrate potential EJ areas in Region B (Figure 2.8). The mapping indicates that some census blocks in Otsego County (town of Oneonta) and Sullivan County (towns of Delaware, Rockland, Liberty, Fallsburg, Bethel, and Thompson) are potential EJ areas based on their minority and/or low-income populations. There are no mapped potential EJ areas in Delaware County.

According to the *2010 Census of Population and Housing*, approximately 97.9% of the individuals in Region B identify themselves as being of a single race: 89.6% of the population of Region B self-identifies as White; 4.7% as Black or African American; 0.3% as American Indian and Alaska Native; 1.1% as Asian; less than (<) 0.01% as Native Hawaiian and Other Pacific Island; and 2.1% as some other race (USCB 2010). The remaining 2.1% self-identify as being of two or more races.

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as a Hispanic or Latino on the 2010 Census, regardless of race. In Region B, 5.0% of the population self-identifies as being Hispanic or Latino.

Table 2.89 presents a summary of the total population of Region B by the race/ethnicity categories defined by the USCB.

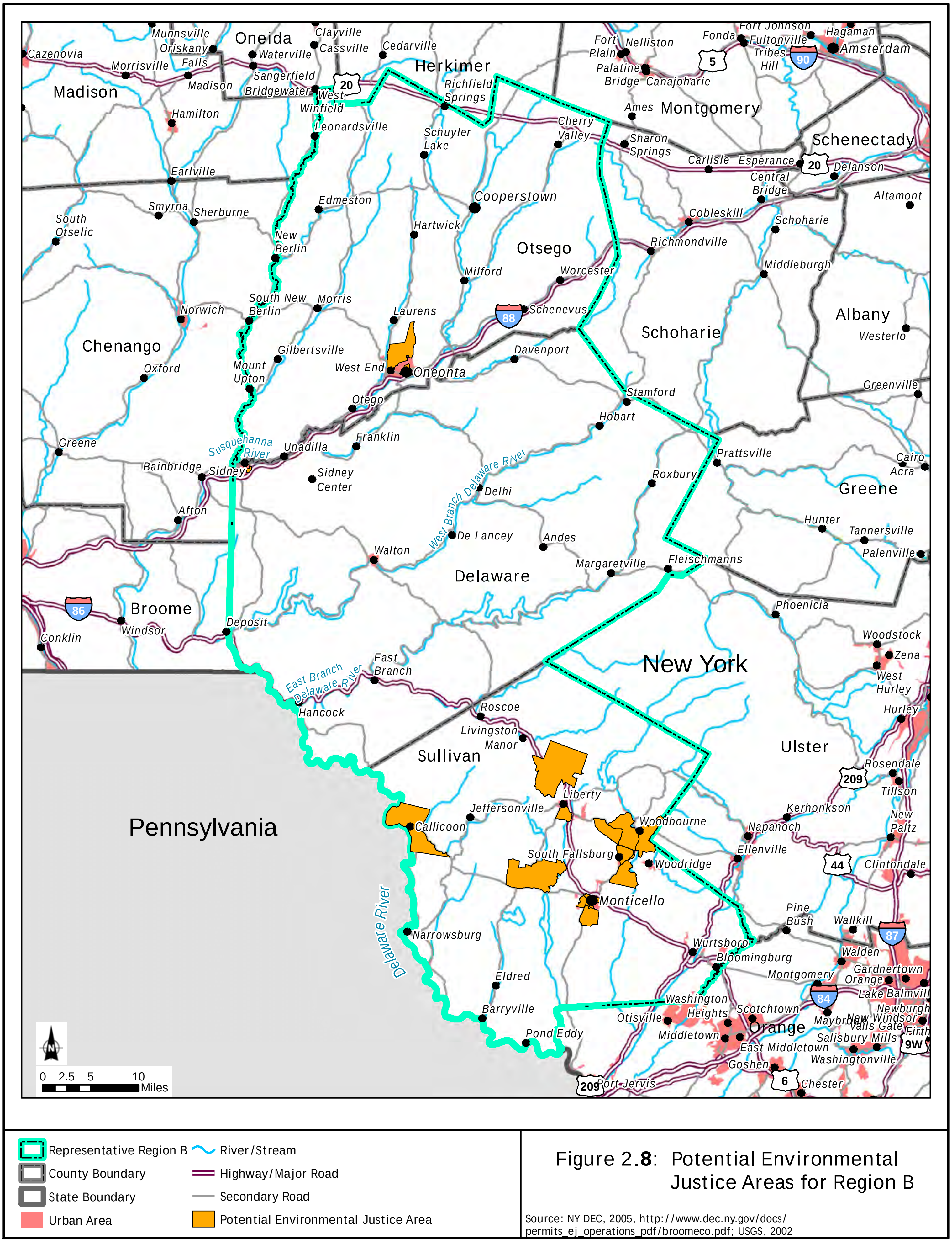


Figure 2.8: Potential Environmental Justice Areas for Region B

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.89 - Region B: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Delaware County		
Total 2010 Population	47,980	100.0%
White Only	45,675	95.2%
Black or African American Only	779	1.6%
American Indian and Alaska Native Only	131	0.3%
Asian Only	367	0.8%
Native Hawaiian and Other Pacific Islander Only	12	< 0.1%
Some Other Race Only	394	0.8%
Total Population of One Race	47,358	98.7%
Two or more races	622	1.3%
Hispanic or Latino	1,058	2.2%
Otsego County		
Total 2010 Population	62,259	100.0%
White Only	58,935	94.7%
Black or African American Only	1,066	1.7%
American Indian and Alaska Native Only	121	0.2%
Asian Only	674	1.1%
Native Hawaiian and Other Pacific Islander Only	18	< 0.1%
Some Other Race Only	413	0.7%
Total Population of One Race	61,227	98.4%
Two or more races	1,032	1.7%
Hispanic or Latino	1,391	2.2%
Sullivan County		
Total 2010 Population	77,547	100.0%
White Only	63,560	82.0%
Black or African American Only	7,039	9.1%
American Indian and Alaska Native Only	354	0.5%
Asian Only	1,075	1.4%
Native Hawaiian and Other Pacific Islander Only	24	< 0.1%
Some Other Race Only	3,229	4.2%
Total Population of One Race	75,281	97.2%
Two or more races	2,266	2.9%
Hispanic or Latino	6,986	9.0%
Region B Total		
Total 2010 Population	187,786	100.0%
White Only	168,170	89.6%
Black or African American Only	8,884	4.7%
American Indian and Alaska Native Only	606	0.3%
Asian Only	2,116	1.1%
Native Hawaiian and Other Pacific Islander Only	54	< 0.1%
Some Other Race Only	4,036	2.1%
Total Population of One Race	183,866	97.9%
Two or more races	3,920	2.1%
Hispanic or Latino	9,435	5.0%

Source: USCB 2010.
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

Region C

Region C comprises Chautauqua and Cattaraugus Counties. The 2010 combined percent minority for Region C was 7.30%. Region C had a combined percent Hispanic population of 2.68%, with Chautauqua County having a higher percentage (3.70%) than Cattaraugus County. Region C is not considered a minority community. The combined poverty level of Region C was 2.3% in 2009. The poverty level for Region C is lower than the New York State EJ threshold for a low-income community (23.59%).

The Department's 2005 preliminary screen mapping was combined to illustrate potential EJ areas in Region C (Figure 2.9). The mapping indicates that some census blocks in Cattaraugus County are potential EJ areas based on their minority and/or low-income populations. These municipalities include Perrysburg, Leon, New Albion, Conewango, Albion, South Valley, Cold Spring, Red House, Salamanca, Carrolton, and Allegany. Some census blocks in Chautauqua County (Jamestown, Portland, Pomfret, Dunkirk and Hanover) are potential EJ areas.

According to the *2010 Census of Population and Housing*, 98.2% of the individuals in Region C identify themselves as being of a single race: 92.7% of the population of Region C self-identifies as White; 2.0% as Black or African American; 1.5% as American Indian and Alaska Native; 0.6% as Asian; less than 0.1% as Native Hawaiian and Other Pacific Island; and 1.4% as some other race (USCB 2010). The remaining 1.9% self-identify as being of two or more races.

Persons of Hispanic or Latino origin are defined as individuals who identified themselves as Hispanic or Latino on the 2010 Census, regardless of race. In Region C, 2.7% of the population self-identifies as being Hispanic or Latino.

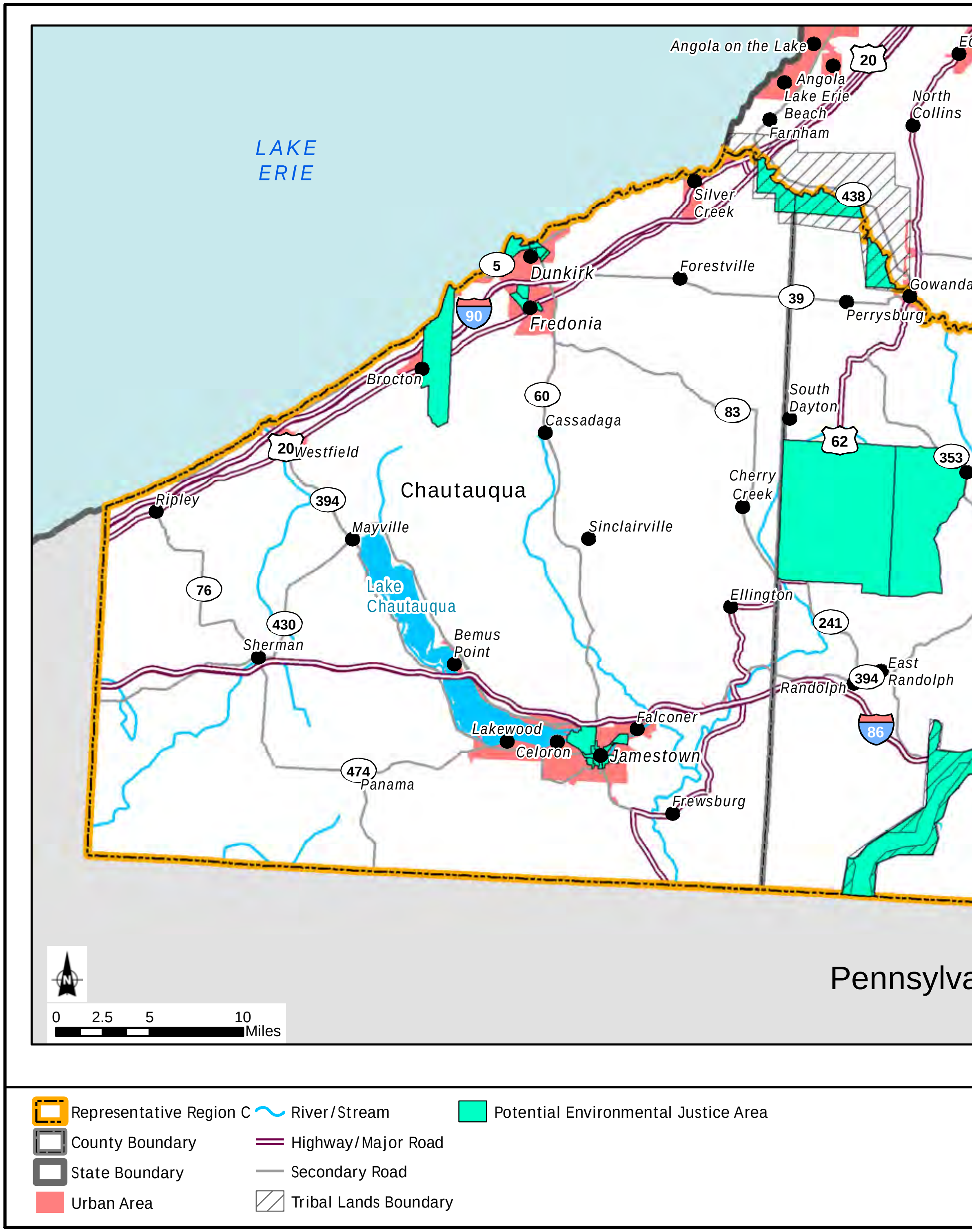


Figure 2.9: Potential Environmental Justice Areas for Region C

Source: NY DEC, 2005, http://www.dec.ny.gov/docs/permits_ej_operations_pdf/broomeco.pdf; USGS, 2002

Table 2.90 presents a summary of the total population of Region C by the race/ethnicity categories defined by the USCB.

Table 2.90 - Region C: Racial and Ethnicity Characteristics (New August 2011)

Population Category	Population	Percentage of Total 2010 Population
Cattaraugus County		
Total 2010 Population	80,317	100.0%
White Only	74,639	92.9%
Black or African American Only	1,024	1.3%
American Indian and Alaska Native Only	2,443	3.0%
Asian Only	528	0.7%
Native Hawaiian and Other Pacific Islander Only	15	< 0.1%
Some Other Race Only	305	0.4%
Total Population of One Race	78,954	98.3%
Two or more races	1,363	1.7%
Hispanic or Latino	786	1.0%
Chautauqua County		
Total 2010 Population	134,905	100.0%
White Only	124,875	92.6%
Black or African American Only	3,197	2.4%
American Indian and Alaska Native Only	689	0.5%
Asian Only	688	0.5%
Native Hawaiian and Other Pacific Islander Only	36	< 0.1%
Some Other Race Only	2,669	2.0%
Total Population of One Race	132,154	98.0%
Two or more races	2,751	2.0%
Hispanic or Latino	4,991	3.7%
Region C Total		
Total 2010 Population	215,222	100.0%
White Only	199,514	92.7%
Black or African American Only	4,221	2.0%
American Indian and Alaska Native Only	3,132	1.5%
Asian Only	1,216	0.6%
Native Hawaiian and Other Pacific Islander Only	51	< 0.1%
Some Other Race Only	2,974	1.4%
Total Population of One Race	211,108	98.2%
Two or more races	4,114	1.9%
Hispanic or Latino	5,777	2.7%

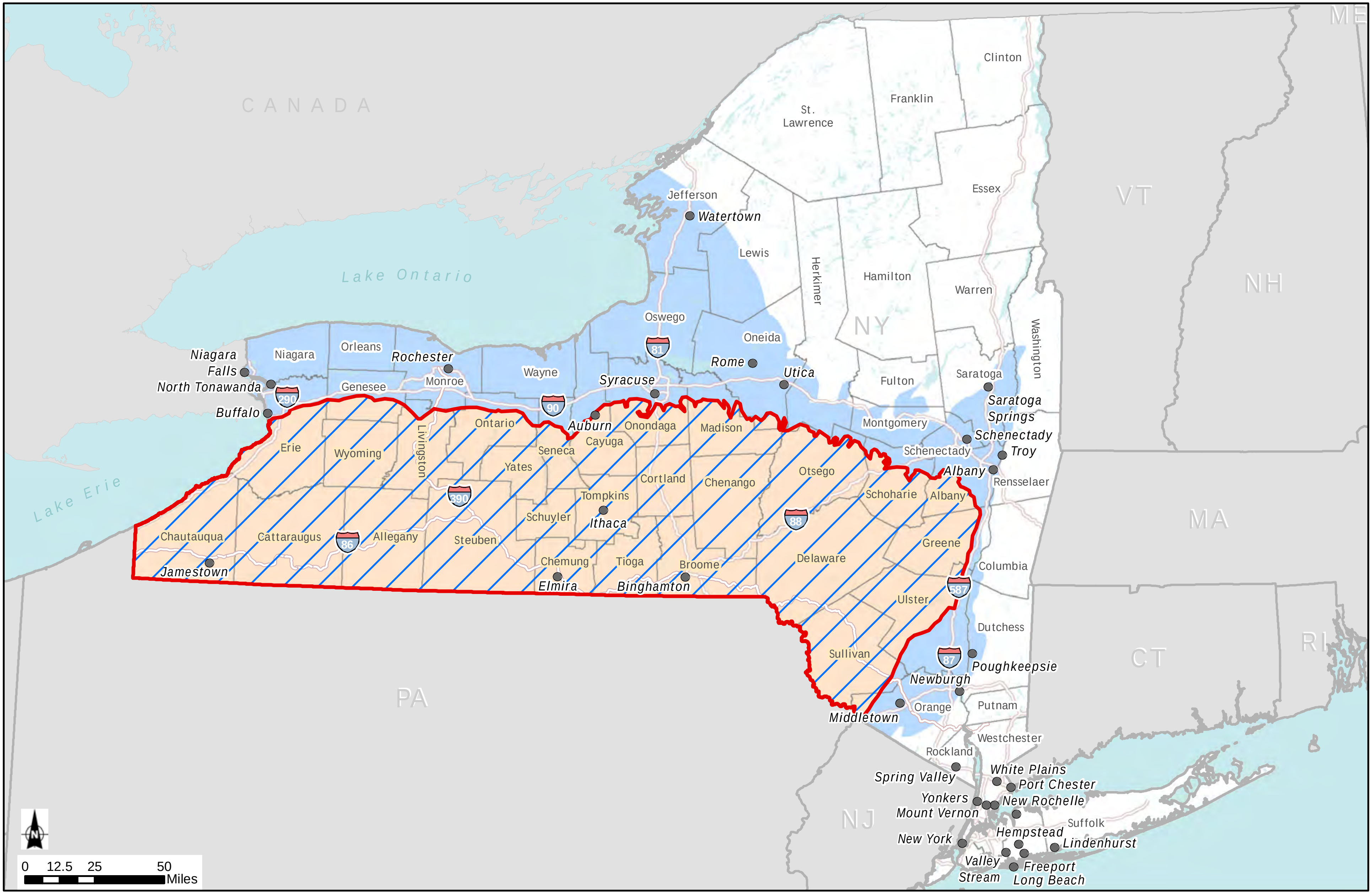
Source: USCB 2010.
The categories presented in this table are defined by the USCB. A person must have self-identified during the 2010 census to be included within any of these categories in the *2010 Census of Population and Housing*.

2.3.12 Visual Resources[46]

As stated in Section 1.3, oil and gas drilling is expected to occur statewide, with the exceptions of (1) state-owned lands that constitute the Adirondack and Catskill Forest Preserves (the state constitution requires that these areas remain forever wild and not be leased or sold), and (2) those areas of the Adirondacks region, NYC, and Long Island where subsurface geology renders drilling for hydrocarbons unlikely. No site-specific project locations are being evaluated in the SGEIS; however, the Marcellus and Utica Shales are the most prominent shale formations in New York State, and the prospective region for the extraction of natural gas from these formations generally extends 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 (Figure 2.10). This region covers all or parts of 30 counties. Fourteen counties are located entirely within this area, and 16 counties are located partially within the area.

For the purposes of impact analysis, visual resources located within the areas underlain by the Marcellus and Utica Shales in New York may be considered representative of the types of visual resources that would be encountered statewide. Therefore, this section describes the existing federally and state-designated visual resources within the boundaries of this area in New York. The potential for other visual resources and visually sensitive areas within the areas underlain by the Marcellus and Utica Shales in New York, which are defined by regional planning entities, county and town agencies, and local communities and their residents, is also acknowledged in this section. All of these types of visual resources and visually sensitive areas (federal, state, and local) also contribute to the 'sense of place' that defines the character of a community, which is discussed in Section 2.3.15.

[46] Subsection 2.4.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.



City with Year 2000 Population Greater than 25,000

Major Water Bodies

County Boundary

State Boundary

Boundary of Area of Interest for Visual Resources

Marcellus Shale Extent in New York State

Utica Shale Extent in New York State

Extent of Marcellus and Utica Shales in New York State

Figure 2.**10**: Area of Interest for Visual Resources

Source: ESRI, 2010; USGS, 2002

Criteria for identifying visual resources are defined in the Department's Program Policy DEP-00-2, "Assessing and Mitigating Visual Impacts" (NYSDEC 2000). Federally designated visual resources include, but are not limited to, National Historic Landmarks (NHL); properties listed in the National Register of Historic Places (NRHP); National Natural Landmarks (NNL); National Wildlife Refuges; National Parks, Recreation Areas, Seashores and Forests, as applicable; National Wild and Scenic Rivers and American Heritage Rivers; and National Scenic, Historic and Recreation Trails.

State-designated visual resources include, but are not limited to, properties listed or eligible for listing in the State Register of Historic Places; Heritage Areas (formerly Urban Cultural Parks); State Forest Preserves; State Game Refuges, State Wildlife Management Areas and Multiple Use Areas; State Parks, Day Use Areas, Nature Preserves and Historic Preserves; State Wild, Scenic and Recreational Rivers; State Scenic Byways, Parkways and Roads; State Conservation Areas and other sites, areas, lakes, or reservoirs designated or eligible for designation as scenic in accordance with ECL Article 49 or the DOT equivalent; Critical Environmental Areas; Scenic Areas of Statewide Significance; State Trails; and Bond Act Properties purchased under the Exceptional Scenic Beauty or Open Space Category. The New York Statewide Trails Plan, Open Space Conservation Plan, and Statewide Comprehensive Outdoor Recreation Plan were also consulted during the development of the existing environmental setting for visual resources (OPRHP 2008, 2009, 2010).

Based on NYSDEC Program Policy DEP-00-2, the visual resources analysis for this draft SGEIS includes the following:

- The definitions of the specific visual resource or visually sensitive area, including descriptions of relevant regulations, where appropriate.
- The number of the specific visual resources or visually sensitive areas within the area underlain by the Marcellus and Utica Shales in New York organized by county, where appropriate.
- Figures showing the locations of specific visual resources or visually sensitive areas within the area underlain by the Marcellus and Utica Shales in New York.

- Where appropriate, a table summarizing information for specific visual resources or visually sensitive areas, generally focusing on visual, aesthetic, or scenic qualities of the resource, if known, and organized by county.

2.3.12.1 Historic Properties and Cultural Resources

This section discusses historic properties and other cultural resources that are considered visual resources per NYSDEC Program Policy DEP-00-2, including properties listed in the National and State Registers of Historic Places (including National Historic Landmarks), state historic sites, state historic parks, and state heritage areas (formerly urban cultural parks) (NYSDEC 2000). Historic properties and cultural resources are often considered significant partly because of their associated visual or aesthetic qualities. These visual or aesthetic qualities may be related to the integrity of the appearance of these properties or resources, or to the integrity of their settings. Viewsheds can also contribute to the significance of historic properties or cultural resources, and viewsheds that contain historic properties and cultural resources may be considered significant because of their presence in the landscape.

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)

Historic properties are defined as those properties that have been listed in, or determined eligible for listing in, the NRHP (Advisory Council on Historic Preservation 2011). The NRHP, which is the official list of the nation's historic places worthy of preservation, was established under the National Historic Preservation Act of 1966, as amended (NPS 2011a; OPRHP 2011a). In general, historic properties are 50 years old or older, and they retain much of their original appearance because of the integrity of their location, design, setting, materials, workmanship, feeling, and association (OPRHP 2011a).

The National Park Service (NPS) maintains a database of properties listed in the NRHP. (This database does not include information for other properties determined to be eligible for listing in the NRHP.) At least 1,050 NRHP-listed properties have been identified within the area underlain by the Marcellus and Utica Shales in New York (Table 2.91) (NPS 2011b, ESRI 2011). The significance of properties listed or eligible for listing on the NRHP may be derived in varying degrees from scenic or aesthetic qualities that may be considered visually sensitive.

Table 2.91 - Number of NRHP-Listed Historic Properties within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name	Number of NRHP-listed Historic Properties within Entire County
Albany*	7
Allegany	27
Broome	52
Cattaraugus	26
Cayuga*	44
Chautauqua	45
Chemung	32
Chenango	39
Cortland	25
Delaware	62
Erie*	28
Genesee*	6
Greene*	45
Livingston*	74
Madison*	48
Oneida*	2
Onondaga*	18
Ontario*	37
Orange*	3
Otsego*	53
Schoharie*	15
Schuyler	14
Seneca*	10
Steuben	49
Sullivan*	64
Tioga	53
Tompkins	57
Ulster*	32
Wyoming	18
Yates	65
Total	1,050

Sources: NPS 2011b; ESRI 2010.

* Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

The State Register of Historic Places, which is the official list of New York State's historic places worthy of preservation, was established under the New York State Historic Preservation act of 1980. The eligibility criteria for properties listed in the State Register of Historic Places are the same as the eligibility criteria for the NRHP (OPRHP 2011a). The OPRHP maintains the database of records for properties listed in, or determined eligible for listing in, the State and National Registers of Historic Places (OPRHP 2011b). Over 250,000 properties located across

New York State are included in this database, and the database provides information on whether the properties have been evaluated for State and/or National Register eligibility, and if evaluated, the eligibility status of the resource (OPRHP 2011c). The significance of properties listed or eligible for listing in the State Register of Historic Places may be derived in varying degrees from scenic or aesthetic qualities that may be considered visually sensitive.

National Heritage Areas

National Heritage Areas (NHAs) are designated by Congress. For an area to be considered for designation, certain key elements must be present. Of primary importance, the landscape must have nationally distinctive natural, cultural, historic, and scenic resources that, when linked together, tell a unique story about the nation. NHAs are not units of the NPS, nor are they owned or managed by the NPS. Each NHA is governed by separate authorizing legislation and operates under provisions unique to its resources and desired goals. The heritage area concept offers an innovative method for citizens, in partnership with local, state, and federal governments and nonprofit and private sector interests, to shape the long-term future of their communities (NPS 2010d, 2011g).

Two NHAs are located partially within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.11): portions of the Erie Canalway National Heritage Corridor in Erie, Ontario, Yates, Seneca, Cayuga, Schuyler, and Tompkins Counties; and portions of the Hudson River Valley NHA in Albany, Greene, Ulster, and Sullivan Counties (OPRHP 2007; NPS 2010d, 2011e; Erie Canalway National Heritage Corridor 2008; Hudson River Valley National Heritage Corridor 2011). These NHAs are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

Properties Designated as National Historic Landmarks

National Historic Landmarks (NHLs) are nationally significant historic places designated by the Secretary of the Interior because they possess exceptional value or quality in illustrating or interpreting the heritage of the United States (NPS 2011c). There are 19 NHLs located within the area underlain by the Marcellus and Utica Shales in New York (Table 2.92 and Figure 2.11). Generally, these NHLs are historic buildings (residences, churches, civic buildings, and institutional buildings), but other types of historic properties are also represented, including battlefields and canals (Table 2.92). The significance of NHL-designated properties may be derived in varying degrees from scenic or aesthetic qualities that may be considered visual resources or visually sensitive.

State Historic Sites and Historic Parks

State Historic Sites and State Historic Parks are historic and cultural places that tell the story of the New York State's rich heritage. Owned by New York State, these places are preserved and interpreted for the public's enjoyment, education, and enrichment (OPRHP 2011d). There are 12 State Historic Sites and two State Historic Parks in the counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York (OPRHP 2008). Of these 14 historic and cultural places, only two are within the area underlain by the Marcellus and Utica Shales in New York: Genesee Valley Canal State Historic Site in Livingston County and Lorenzo State Historic Site in Madison County (see Figure 2.11) (OPRHP 2011d). State Historic Sites and State Historic Parks may contain scenic or aesthetic qualities that may be considered visually sensitive.

Local Visually Sensitive Resources or Areas

The counties that are entirely or partially located within the area underlain by the Marcellus and Utica Shales in New York are expected to contain numerous other local visual resources or visually sensitive areas. These local visual resources or visually sensitive areas would be identified, defined and/or designated by regional planning entities and local (county and town) communities and their residents and would be in addition to the visual resources or visually sensitive areas described above that are defined or designated by federal and state agencies and guidance.

Table 2.92 - National Historic Landmarks (NHLs) Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of NHLs within County	Names of NHLs
Broome	1	• New York State Inebriate Asylum
Cayuga**	6	• William H. Seward House • Harriet Tubman Home for the Aged • Harriet Tubman Residence • Thompson A.M.E. Zion Church • Willard Memorial Chapel-Welch Memorial Hall • Jethro Wood House
Chautauqua	2	• Chautauqua Historic District • Lewis Miller Cottage, Chautauqua Institute
Chemung	1	• Newton Battlefield
Delaware	1	• John Burroughs Memorial (Woodchuck Lodge)
Erie**	2	• Millard Fillmore House • Roycroft Campus
Madison**	1	• Gerrit Smith Estate
Orange**	1	• Delaware and Hudson Canal***
Otsego**	1	• Hyde Hall
Seneca**	1	• Rose Hill
Sullivan**	1	• Delaware and Hudson Canal***
Tompkins	1	• Morrill Hall, Cornell University
Ulster**	2	• John Burroughs Riverby Study • Delaware and Hudson Canal***
Total	**19**	

Sources: ESRI 2010; NPS 2011d; OPRHP 2008.

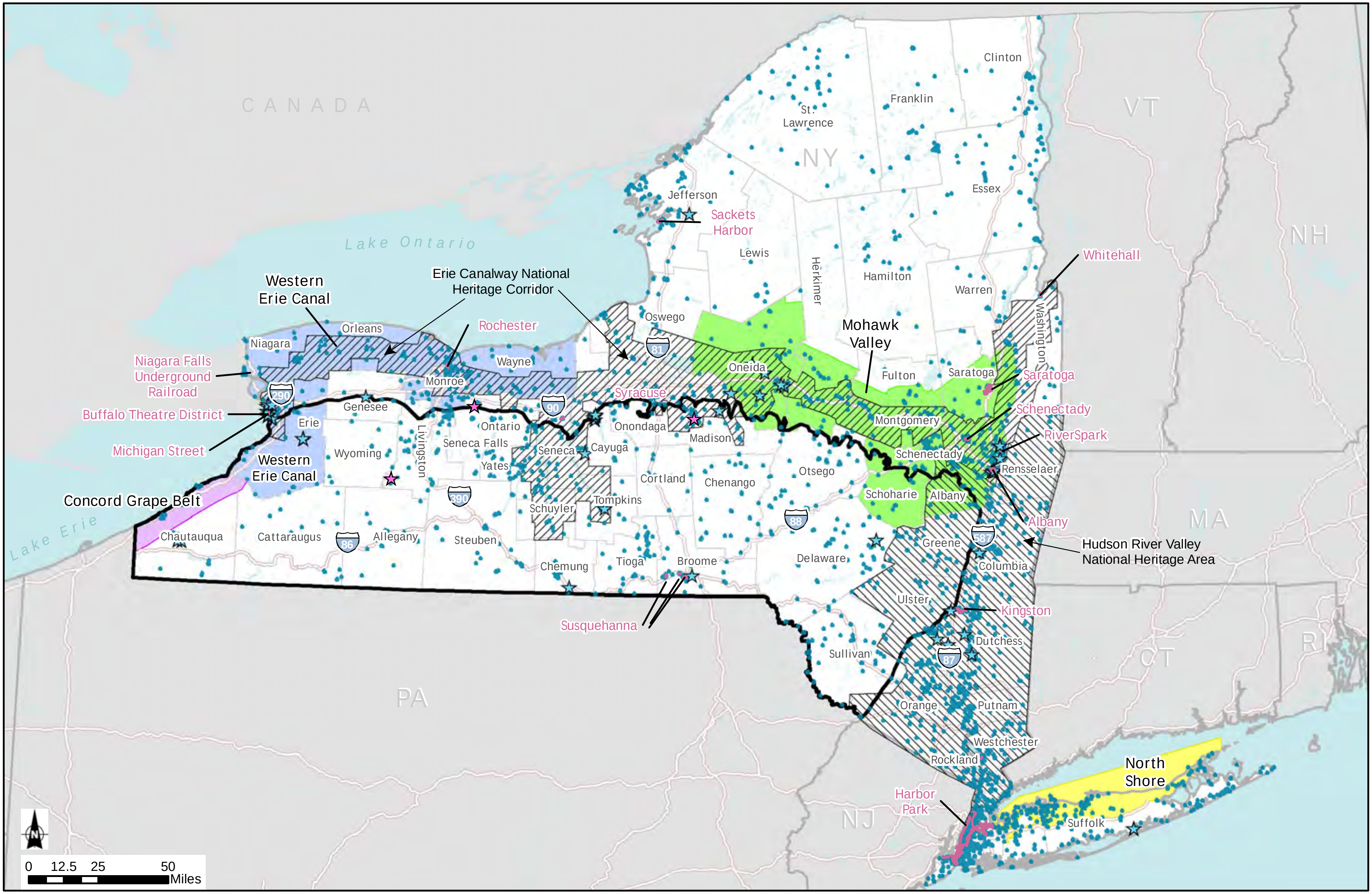
* There are no NHLs within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** The Delaware and Hudson Canal NHL traverses portions of three counties (Orange, Sullivan, and Ulster).

State Heritage Areas (former Urban Cultural Parks [Parks, Recreation and Historic Preservation Law Section 35.15])

The State Heritage Area System, formerly known as the Urban Cultural Park System, is a state and local partnership established to preserve and develop areas that have special significance to New York State (OPRHP 2011e). New York State Heritage Areas are places where unique qualities of geography, history, and culture create a distinctive identity that becomes the focus of four heritage goals: preservation of significant resources; education that interprets lessons from the past; recreation and leisure activities; and economic revitalization for sustainable communities (OPRHP 2011f). Four regional or urban heritage areas or corridors are located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.11): the Concord Grape Belt (Lake Erie) Heritage Area in Chautauqua and Cattaraugus Counties; portion of the Western Erie Canal Heritage Area in southern Erie County; portions of the Mohawk Valley Heritage Area in Oneida, Schoharie, and Albany Counties; and the Susquehanna Heritage Area in Broome County (OPRHP 2007, 2011e; 2011f; Concord Grape Belt Heritage Association 2011; Western Erie Canal Alliance 2010-2011). These State Heritage Areas are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.



Major Water Bodies	Erie Canalway NHA	State Regional Heritage Area	National Register of Historic Places Site
County Boundary	Hudson River Valley NHA	Western Erie Canal	National Historic Landmark
State Boundary	State Urban Hertage Area	Concord Grape Belt	State Historic Site
Boundary of Area of Interest for Visual Resources		Mohawk Valley	
		North Shore	

Figure 2.11: Visually Sensitive Areas Associated with Historic Properties and Cultural Resources

Source: ESRI, 2010; USGS, 2002; OPRHP, 2007, 2009, 2011; NYCSCIC, 2005; NPS, 2007

2.3.12.2 Parks and Other Recreation Areas

This section discusses parks and other recreation areas that are considered visual resources per NYSDEC Program Policy DEP-00-2, “Assessing and Mitigating Visual Impacts,” including state parks; properties included in the National Park System and areas defined as national recreation areas, seashores and forests; and state or federally designated trails (NYSDEC 2000). These recreation areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

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

State Parks contain natural, historic, cultural, and/or recreational resources of significance to New York State. (Note that State Historic Parks are discussed separately in Section 2.3.12.1). Owned by New York State, these parks are maintained for the public’s use. Thirty-four state parks are located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.93 and Figure 2.12) (OPRHP 2008). These parks may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

Table 2.93 - State Parks Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Parks within County	Names of State Parks within County
Albany**	1	• John Boyd Thacher State Park
Broome	2	• Chenango Valley State Park • Oquaga Creek State Park
Cattaraugus	1	• Allegany State Park
Cayuga**	2	• Fillmore Glen State Park • Long Point State Park
Chautauqua	2	• Lake Erie State Park • Long Point on Lake Chautauqua State Park
Chemung	1	• Mark Twain State Park
Chenango	2	• Hunts Pond State Park • Bowman Lake State Park
Delaware	1	• Oquaga Creek State Park
Erie**	3	• Evangola State Park • Woodlawn Beach State Park • Knox Farm State Park
Genesee**	1	• Darien Lakes State Park
Livingston**	1	• Letchworth State Park
Madison**	2	• Chittenango Falls State Park • Helen L McNitt State Park (undeveloped)
Otsego**	3	• Gilbert Lake State Park • Betty and Wilbur Davis State Park • Glimmerglass State Park
Schoharie**	2	• Max V. Shaul State Park • Mine Kill State Park
Schuyler	1	• Watkins Glen State Park
Seneca**	3	• Seneca Lake State Park • Sampson State Park • Taughannock Falls State Park
Steuben	2	• Stony Brook State Park • Pinnacle State Park
Sullivan**	1	• Lake Superior State Park
Tompkins	3	• Taughannock Falls State Park • Robert H. Treman State Park • Buttermilk Falls State Park
Wyoming	2	• Letchworth State Park • Silver Lake State Park (undeveloped)
Yates	1	• Keuka Lake State Park
Total	34***	

Sources: ESRI 2010; OPRHP 2008.
* No state parks within other counties entirely or partially within the area underlain by the Marcellus and Utica Shales in NYS.
** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.
***Letchworth State Park is in two counties (Wyoming and Livingston); Oquaga Creek State Park is in two counties (Broome and Delaware); Taughannock Falls State Park is in two counties (Seneca and Tompkins).

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

Properties included in the National Park System and areas defined as National Recreation Areas, Seashores and Forests contain natural, historic, cultural, and recreational resources of significance to the nation. Owned by the U.S. government and operated by various federal agencies, they are maintained for the public's use. At least five properties included in the National Park System are located in counties that are partially or entirely within the area underlain by the Marcellus and Utica Shales in New York: Women's Rights National Historic Park in Seneca County; Fort Stanwix National Monument in Oneida County; the North Country National Scenic Trail, which traverses New York State; Old Blenheim Covered Bridge in Schoharie County; and the Upper Delaware Scenic & Recreational River in Orange, Sullivan, and Delaware Counties (OPRHP 2008). One National Forest, the Finger Lakes National Forest in Seneca and Schuyler Counties, is located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.12) (OPRHP 2008). No National Recreation Areas or National Seashores are located within the area underlain by the Marcellus and Utica Shales in New York (OPRHP 2008). The federally-owned National Park System properties and the National Forest may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

A state or federally designated trail, or one proposed for designation (16 U.S.C. Chapter 27 or equivalent)

New York State's natural and cultural resources provide for a broad range of land and water-based trails that offer multiple recreational experiences (Table 2.94). Each region of the state offers a unique setting and different opportunities for trails (OPRHP 2008). New York State breaks the existing system of trails into three general categories: primary trails that are of national, statewide, or regional significance and that are considered long-distance trails; secondary trails, which typically connect to a primary trail system but are generally within parks or open space areas; and stand-alone trails, which are trails of local significance that do not connect to a primary trail system. Stand-alone trails are generally loop trails, trails that connect to points of interest, or trails that provide short connections between parks, open spaces, historic sites and/or communities, or elements of a community (OPRHP 2008).

Additional state-designated trails include heritage trails, greenway trails, and/or water trails. Heritage trails are existing non-linear resources associated with historical movements or themes (OPRHP 2007, 2010). Greenway trails are existing and proposed multi-use trails located within linear corridors of open space that connect public places, connect people with nature, and protect areas for environmentally sustainable purposes that include recreation, conservation, and transportation (OPRHP 2007, 2010). Water trails, also known as blueways, are existing and proposed designated recreational water routes suitable for canoes, kayaks, and small motorized watercraft (OPRHP 2010).

One federally recognized trail, the North Country National Scenic Trail, traverses portions of the area underlain by the Marcellus and Utica Shales in New York. The North Country National Scenic Trail, an approximately 3,200-mile-long trail extending from eastern New York State to North Dakota, is administered by the NPS (NPS 2010a, 2010b). The portion of the trail in New York is included in the system of trails shown on Figure 2.12. National Scenic Trails are designated under Section 5 of the National Trails System Act and are defined as extended trails located to provide for maximum outdoor recreation potential and for the conservation and enjoyment of the nationally significant scenic, historic, natural, or cultural qualities of the areas though which they pass (NPS 2010a). A number of these types of trails are shown on Figure 2.12. All of these types of trails are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive

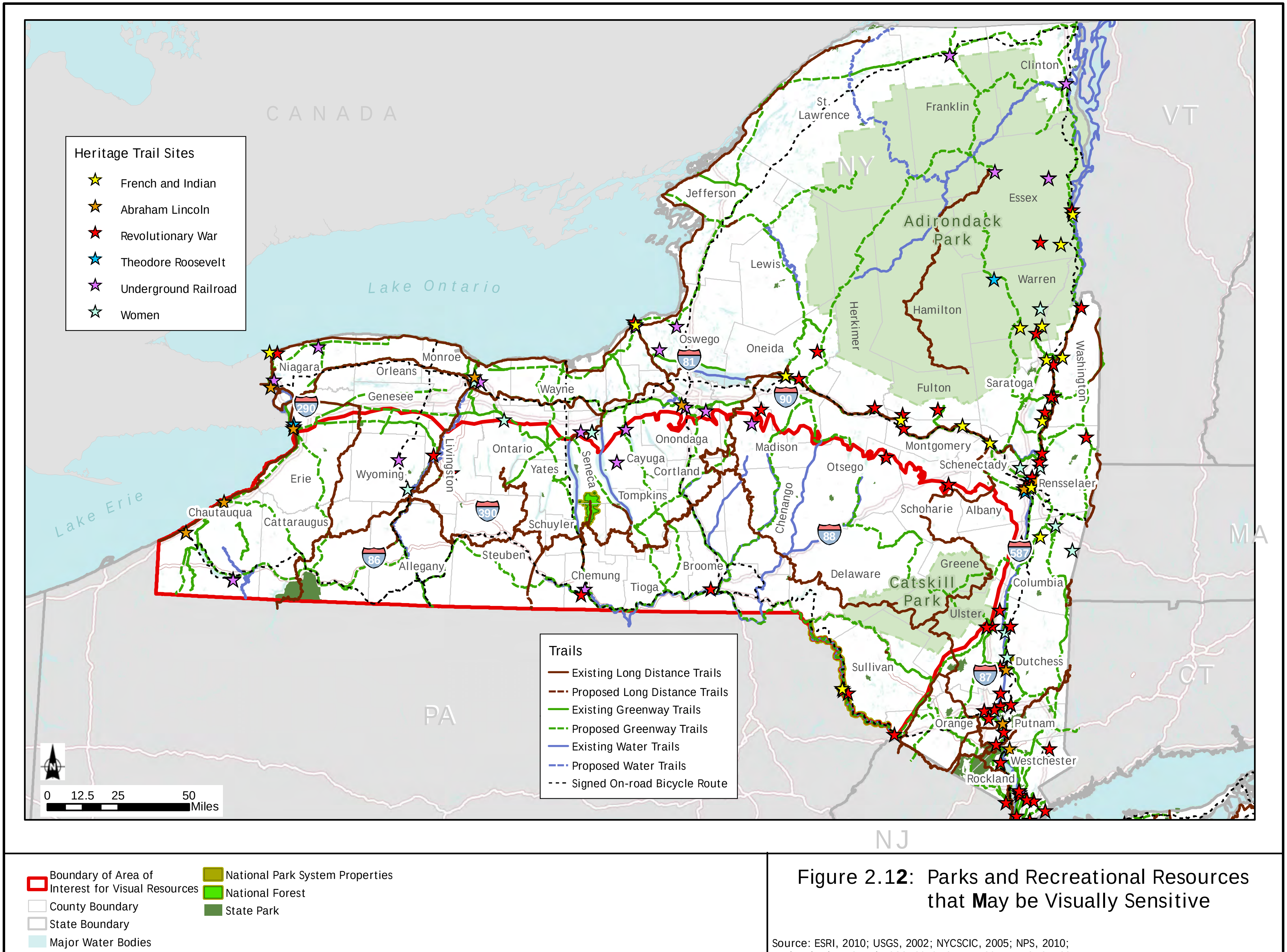


Figure 2.12: Parks and Recreational Resources that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYCSCIC, 2005; NPS, 2010; National Atlas US and USGS, 2010; OPRHP, 2011; NYSDOT, 2011

Table 2.94 - Select Trails Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

Name of Trail	**Type of Trail**
North County National Scenic Trail*	• Long-distance trail of national significance
Long Path*	• Long-distance trail of statewide significance
Finger Lakes Trail*	• Long-distance trail of statewide significance
Canalway Trail*	• Long-distance trail of statewide significance
Hudson River Valley Greenway Trail System*	• Long-distance trail of statewide significance
Hudson River Greenway Water Trail*	• Long-distance trail of statewide significance
Genesee Valley Greenway*	• Long-distance trail of statewide significance
The statewide Snowmobile Trail System*	• Long-distance trail of statewide significance
Conservation Trail*	• Long-distance hiking trail of regional significance
Letchworth Trail*	• Long-distance hiking trail of regional significance
Bristol Hills Trail*	• Long-distance hiking trail of regional significance
Link Trail*	• Long-distance hiking trail of regional significance
Shawangunk Ridge Trail	• Long-distance hiking trail of regional significance
Abraham Lincoln Heritage Trail	• State-designated Heritage Trail consisting of resources in Chautauqua, Onondaga, and Albany Counties
Women Heritage Trail	• State-designated Heritage Trail consisting of resources in Chautauqua, Wyoming, Ontario, Seneca, and Cayuga Counties
Underground Railroad Heritage Trail	• State-designated Heritage Trail consisting of resources in Wyoming, Chemung, Seneca, Cayuga, Onondaga, and Madison Counties
Revolutionary War Heritage Trail	• State-designated Heritage Trail consisting of resources in Chemung, Broome Madison, Otsego Schoharie, Sullivan and Orange Counties
French and Indian Heritage Trail	• State-designated Heritage Trail consisting of resources in Sullivan County
Catherine Valley Trail	• Multi-use trail located within linear corridors of open space in Chemung and Schuyler Counties
Catskill Scenic Trail	• Multi-use trail located within linear corridors of open space in Delaware County
Delaware & Hudson Canal Trail	• Multi-use trail located within linear corridors of open space in Sullivan and Ulster Counties
Erie Canalway Trail*	• Multi-use trail located within linear corridors of open space
Genesee Valley Greenway*	• Multi-use trail located within linear corridors of open space
Ontario Pathways Rail Trail	• Multi-use trail located within linear corridors of open space in Ontario County
Orange Heritage Trail	• Multi-use trail located within linear corridors of open space in Orange County
Pat McGee Trail	• Multi-use trail located within linear corridors of open space in Cattaraugus County
Wallkill Valley Rail Trail	• Multi-use trail located within linear corridors of open space in Ulster County
Marden Cobb Waterway Trail	• Recreational water route
Cayuga-Seneca Canal Trail, which is a component of the larger NYS Canalway Water Trail*	• Recreational water route
Chemung Basin River Trail*	• Recreational water route
Headwaters River Trail(s)*	• Recreational water route
Upper Delaware Scenic and Recreational River*	• Recreational water route
Proposed Triple Divide Water Trail*	• Proposed recreational water route

Sources: ESRI 2010; OPRHP 2007, 2010; NPS 2010a, 2010b.
* Trail traverses one or more counties

2.3.12.3 Natural Areas

This section discusses natural areas that are considered visual resources per NYSDEC Program Policy DEP-00-2, including state forest preserve areas; state nature and historic preserves; state or national wild, scenic and recreational rivers (designated and potential); national wildlife refuges, state game refuges, and state wildlife management areas; and national natural landmarks (NYSDEC 2000). These natural areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

The State Forest Preserve (NYS Constitution Article XIV)

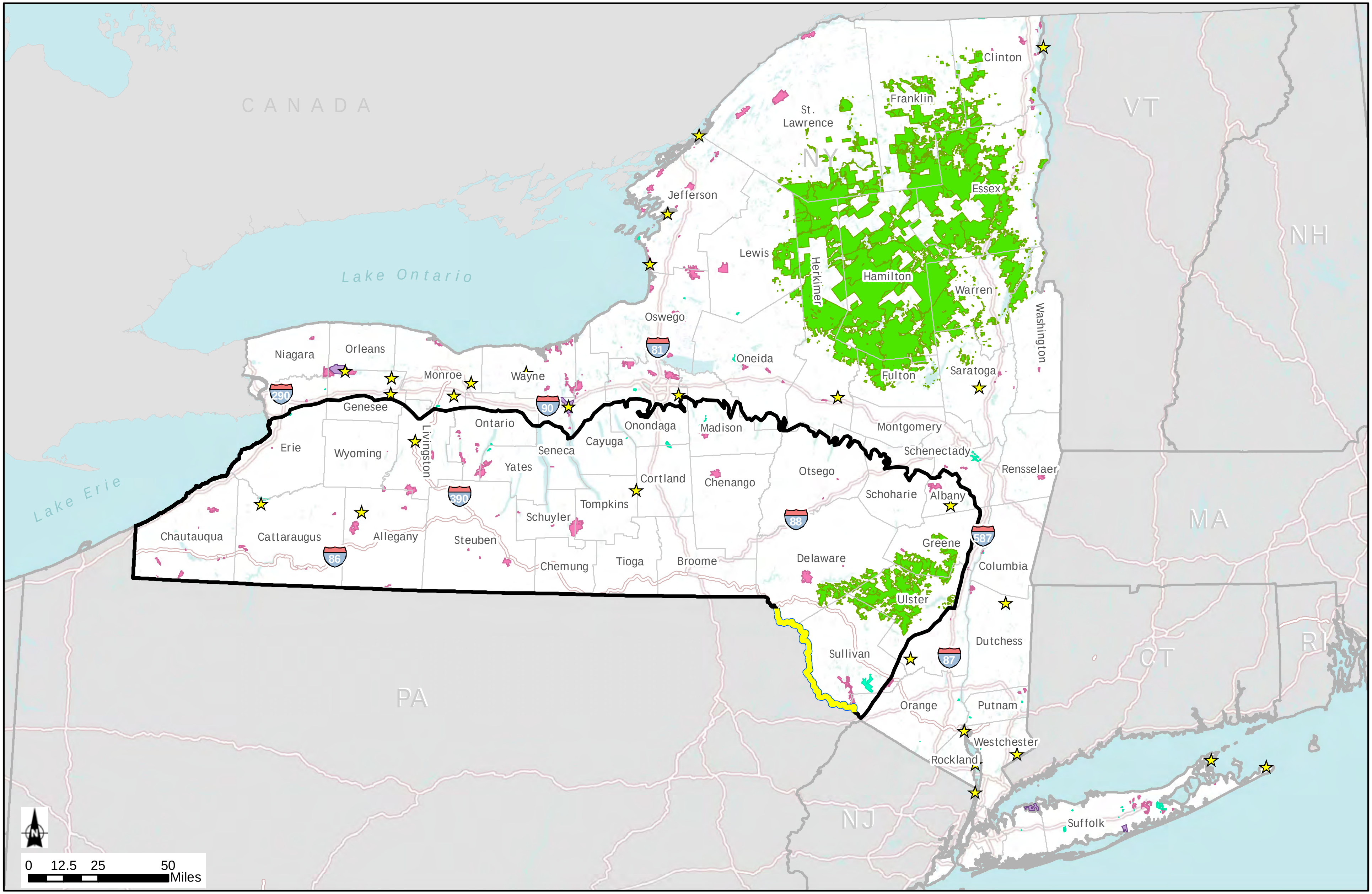
The State Forest Preserve consists of lands included in the Adirondack Forest Preserve (approximately 2.6 million acres) and the Catskill Forest Preserve (approximately 290,000 acres). These lands, which represent the majority of all state-owned property within the Adirondack and Catskill Parks, are protected as “forever wild” under Article XIV of the New York State Constitution. They are recognized as having exceptional scenic, recreational, and ecological value (NYSDEC 2011a, 2011b, 2011c).

The Adirondack Forest Preserve, located entirely within the Adirondack Park boundaries, is outside the area underlain by the Marcellus and Utica Shales in New York. The Catskill Forest Preserve, located entirely within the Catskill Park boundaries, is located within the eastern part of this area in portions of Delaware, Greene, Ulster, and Sullivan Counties (Figure 2.12). Lands included in the Catskill Forest Preserve are likely to contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.

State Nature and Historic Preserves (Section 4 of Article XIV of State Constitution)

State nature and historic preserves are parcels of land owned by the state that were acquired to protect the biological diversity of plants, animals, and natural communities, and which may provide a field laboratory for the observation of and education in these relationships. These areas may also provide for the protection of places of historical and natural interest, and may be used by the public for passive recreational pursuits that are compatible with protection of the ecological significance, historic features, and/or natural character of the areas designated as state nature and historic preserves (NYSDEC 2011d).

Eight state nature and historic preserves are located in the counties within the area underlain by the Marcellus and Utica Shales in New York (Table 2.95). These state nature and historic preserves may contain scenic or aesthetic areas that may be considered visual resources or visually sensitive.



Major Water Bodies
County Boundary
State Boundary
Boundary of Area of Interest for Visual Resources
National Natural Landmark
National Wild and Scenic River
National Wildlife Refuge
State Forest Preserve
State Unique Area
State Wildlife Management Area

Figure 2.13: Natural Areas that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYDEC, 2010; NPS, 2011; National Atlas US and USGS, 2010

Table 2.95 - State Nature and Historic Preserves in Counties Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Nature and Historic Preserves within County	Names of State Nature and Historic Preserves
Allegany	1	• Showy Lady Slipper Parcel (Town of New Hudson)
Cattaraugus	1	• Zoar Valley Unique Area (Towns of Otto and Persia)
Cortland	2	• Bog Brook (Towns of Southeast and Patterson) • Labrador Hollow (Town of Truxton)
Erie**	2	• Reinstein Woods (Town of Cheektowaga) • Zoar Valley Unique Area (Town of Collins)
Onondaga**	1	• Labrador Hollow (Town of Fabius)
Ontario**	1	• Squaw Island (Town of Canandaigua)
Yates	2	• Parish Gully (Town of Italy) • Clark Gully (Towns of Middlesex and Italy)
Total	**8*** **	

Sources: ESRI 2010; OPRHP 2008; NYSDEC 2011d.

* There are no State Nature and Historic Preserves within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** Labrador Hollow is in two counties (Onondaga and Cortland); Zoar Valley Unique Area is in two counties (Cattaraugus and Erie).

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

National Wild, Scenic or Recreational Rivers are those rivers designated by Congress or the Secretary of the Interior in accordance with the Wild and Scenic Rivers Act of 1968. The purpose of such designation is to preserve those rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations. Wild rivers are those rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watershed or shorelines essentially primitive and waters unpolluted. These represent vestiges of primitive America. Scenic rivers are those rivers or sections of rivers that are free of impoundments, with shorelines or a watershed still largely primitive and shorelines largely undeveloped, but accessible in places by roads. Recreational rivers are those rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past (National Wild and Scenic Rivers System 2011a).

A portion of only one river, the Delaware River (also known as the Upper Delaware Scenic and Recreational River), has been designated a National Wild and Scenic River in New York State (National Wild and Scenic Rivers System 2011b, 2011c; NPS 2010c). This portion of the Delaware River, located in Delaware County along the New York-Pennsylvania border, is within the area underlain by the Marcellus and Utica Shales in New York (see Table 2.96 and Figure 2.13). Designated in part for its scenic qualities, this portion of the Delaware River contains scenic areas that may be considered visual resources or visually sensitive.

A portion of one other water body in New York State, the East Branch of Fish Creek, located in Lewis County, was studied for its potential for inclusion in the National Wild and Scenic Rivers System (National Wild and Scenic Rivers System 2011d). This portion of Fish Creek is located in Oneida County, which is partially located within the area underlain by the Marcellus and Utica Shales in New York (Table 2.96).

Section 5(d) of the National Wild and Scenic Rivers Act of 1968 requires federal agencies to consider the effects of planned use and development on potential national wild and scenic river areas. In partial fulfillment of this requirement, the NPS has compiled and maintains a Nationwide Rivers Inventory (NRI), which is a register of river segments that potentially qualify as National Wild, Scenic or Recreational River areas (NPS 2008a).

In order to be listed on the NRI, a river must be free-flowing and possess one or more Outstanding Remarkable Values (ORVs). In order to be assessed as outstandingly remarkable, a river-related value must be a unique, rare, or exemplary feature that is significant at a comparative regional or national scale. Such values must be directly river-related: located in the river or on its immediate shorelands (generally within 0.25 mile on either side of the river); contribute substantially to the function of the river ecosystem; and/or owe their location or existence to the presence of the river. ORVs may involve values associated with scenery, recreation, geology, fish, wildlife, prehistory, history, cultural, or other values (e.g., hydrology, paleontology, or botany resources) (NPS 2008a).

Portions of 17 NRI-listed rivers or water bodies are located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.96). Many of these rivers or water bodies have been designated in part for their scenic qualities, and all of these rivers or water bodies may contain scenic areas that may be considered visual resources or visually sensitive.

State-designated Wild, Scenic and Recreational Rivers are those rivers or portions of rivers of the state of New York protected by the state's Wild Scenic and Recreational Rivers Act. This act protects those rivers of the state that possess outstanding scenic, ecological, recreational, historic, and scientific values. Attributes of these rivers may include value derived from fish and wildlife and botanical resources, aesthetic quality, archaeological significance, and other cultural and historic features. State policy is to preserve designated rivers in a free-flowing condition, protecting them from improvident development and use, and to preserve the enjoyment and benefits derived from these rivers for present and future generations (NYSDEC 2011e).

Portions of two state-designated Wild, Scenic and Recreational Rivers - the Genesee River and the Upper Delaware River - flow within counties located partially or entirely within the area underlain by the Marcellus and Utica Shales in New York (Table 2.96). These rivers have been designated, in part, for their scenic qualities, and both of these rivers may contain scenic areas that may be considered visual resources or visually sensitive.

Table 2.96 - National and State Wild, Scenic and Recreational Rivers (designated or potential) Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Name of River or Water Body	Designation Status
Albany**	• Portion of Catskill Creek***	• Listed in NRI in 1982
Allegany	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River
Cattaraugus	• Portions of Allegheny River • Portions of Cattaraugus Creek*** • Portion of Conewango Creek ***	• Listed in NRI in 1982, updated in 1995 • Listed in NRI in 1982; updated in 1995 • Listed in NRI in 1982
Cayuga**	• Portion of Fall Creek***	• Designated a State Wild, Scenic and Recreational River
Chautauqua	• Portion of Cattaraugus Creek*** • Portion of Chautauqua Creek • Portion of Conewango Creek***	• Listed in NRI in 1982; updated in 1995 • Listed in 1982 • Listed in NRI in 1982
Chemung	• Portion of Chemung River	• Listed in NRI in 1982
Delaware	• Delaware River (Upper)*** • Portions of Delaware River, East Branch	• Designated a National Wild & Scenic River in 1978 • Listed in NRI in 1982 and 1995
Erie**	• Portions of Cattaraugus Creek***	• Listed in NRI in 1982; updated in 1995
Greene**	• Portion of Batavia Kill	• Listed in NRI in 1982
Livingston**	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River
Orange**	• Portion of Basher Kill ***	• Listed in NRI in 1995
Steuben	• Portion of Canisteo River • Portion of Cohocton River	• Listed in NRI in 1995 • Listed in NRI in 1995
Sullivan**	• Delaware River (Upper)*** • Portion of Basher Kill*** • Portion of Beaver Kill*** • Portions of Neversink River, including East and West Branches • Portion of Mongaup Creek	• Designated a National Wild and Scenic River in 1978 • Listed in NRI in 1995 • Listed in NRI in 1992; updated in 1995 • Listed in 1982 and 1995 • Listed in NRI in 1995
Tompkins	• Portion of Fall Creek***	• Designated a State Wild, Scenic and Recreational River
Ulster**	• Portion of Beaver Kill*** • Portion of Esopus Creek • Portions of Neversink River, including East and West Branches	• Listed in NRI in 1992; updated in 1995 • Listed in NRI in 1995 • Listed in 1982 and 1995
Wyoming	• Portions of Genesee River***	• Listed in NRI in 1982; updated in 1995 • Designated a State Wild, Scenic and Recreational River

Sources: ESRI 2010; NPS 2008a, 2009a, 2010c; OPRHP 2008; NYSDEC 2011f.

* There are no national or state Wild, Scenic and Recreational Rivers within other counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York.

*** Portions of the Genesee River are in three counties (Allegany, Wyoming, and Livingston); portions of the Beaver Kill are in two counties (Ulster and Sullivan); portions of Cattaraugus Creek are in three counties (Erie, Cattaraugus, and Chautauqua); Conewango Creek is in two counties (Chautauqua and Cattaraugus); Basher Kill is in two counties (Orange and Sullivan); the Upper Delaware River is in two counties (Delaware and Sullivan); Fall Creek is in two counties (Cayuga and Tompkins).

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

National Wildlife Refuges (NWRs) are a network of lands and waters included in the National Wildlife Refuge system and managed by the U.S. Fish and Wildlife Service. These lands and waters are set aside for the conservation, management and, where appropriate, restoration of fish, wildlife, and plant resources and their habitats. In addition to the task of conserving wildlife, NWRs may also be managed for six wildlife-dependent recreational uses: hunting, fishing, wildlife observation, photography, and environmental education and interpretation. There are three NWRs in counties that are partially within the area underlain by the Marcellus and Utica Shales of New York: The Iroquois NWR in Genesee and Orleans Counties; the Montezuma NWR in Seneca and Wayne Counties; and the Shawangunk Grasslands NWR in Ulster County (USFWS 2011). However, none of the NWRs are located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.13).

New York State's ECL (11-2105) defines state game refuges as lands set aside or established for the protection of wildlife and fish. Such lands remain game refuges until the state permits the taking of wildlife or fish within these lands. State Wildlife Management Areas (WMAs) are lands owned by New York State that have been acquired primarily for the production and use of wildlife, including research on wildlife species and habitat management. WMAs are under the control and management of the Department's DFWMR. While fishing, hunting and trapping are the most widely practiced recreational activities on many WMAs, most also provide opportunities for hiking, cross-country skiing, bird watching, or enjoying nature (NYSDEC 2011g).

There are 42 state game refuges or WMAs within the area underlain by the Marcellus and Utica Shales in New York (Table 2.97 and Figure 2.13). Many of the lands included in state game refuges or WMAs contain scenic areas that may be considered visual resources or visually sensitive.

Table 2.97 - State Game Refuges and State Wildlife Management Areas Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of State Game Refuges and WMAs	Name of State Game Refuges or WMA
Albany**	2	• Louise E. Keir WMA • Partridge Run WMA
Allegany	4	• Alma Pond • Genesee Valley WMA • Hanging Bog WMA • Keeney Swamp WMA
Cattaraugus	2	• Conewango Swamp WMA • Harwood Lake MUA
Chautauqua	8	• Alder Bottom WMA • Canadaway Creek WMA • Clay Pond WMA • Hartson Swamp WMA • Jacquins Pond WMA • Kabob WMA • Tom's Point WMA • Watts Flats WMA
Chenango	1	• Pharsalia WMA
Delaware	2	• Bear Spring Mountain WMA • Wolf Hollow WMA
Erie**	1	• Hampton Brook Woods WMA
Greene**	1	• Vinegar Hill WMA
Livingston**	2	• Conesus Inlet WMA • Rattlesnake Hill WMA
Madison**	1	• Tioughnioga WMA
Ontario**	2	• Honeoye Creek WMA • Stid Hill MUA
Orange**	1	• Cherry Island WMA
Otsego**	2	• Crumhorn Mountain WMA • Hooker Mountain WMA
Schoharie**	1	• Franklinton Vlaie WMA
Schuyler	2	• Catharine Creek WMA • Waneta-Lamoka WMA
Seneca**	1	• Willard WMA
Steuben	4	• Cold Brook WMA • Erwin WMA • Helmer Creek WMA • West Cameron WMA
Sullivan**	2	• Bashakill WMA • Mongaup Valley WMA
Tompkins	1	• Connecticut Hill WMA
Wyoming	1	• Silver Lake Outlet WMA
Yates	1	• High Tor WMA
Total	**42**	

Source: ESRI 2010; NYSDEC 2011g, 2011h; USFWS 2011.

* No other NWRs or state game refuges or wildlife management areas in New York State are located within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales in New York State.

National Natural Landmarks [36 CFR Part 62]

National Natural Landmarks (NNLs) are sites that contain outstanding biological and/or geological resources, regardless of land ownership, and are selected for their outstanding condition, illustrative value, rarity, diversity, and value to science and education. NNL sites are designated by the Secretary of the Interior, with landowner concurrence (NPS 2008b, 2009b, 2011e). Five NNLs are located within the area underlain by the Marcellus and Utica Shales in New York (Figure 2.13 and Table 2.98). These NNLs are a combination of unique ecological settings such as bogs or marshes and geological features (NPS 2011f). They are likely to contain aesthetic areas that may be considered visual resources or visually sensitive.

Table 2.98 - National Natural Landmarks Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Name of National Natural Landmark	Description
Albany	• Bear Swamp	• Designated in 1973 • Low, swampy woodland with relict stands of great laurel
Allegany	• Moss Lake Bog	• Designated in 1973 • Post-glacial sphagnum bog in a small kettle lake
Cattaraugus	• Deer Lick Nature Sanctuary	• Designated in 1967 • Gorge and mature northern hardwood forest
Livingston	• Fall Brook Gorge	• Designated in 1970 • Gorge exposing Upper and Middle Devonian Age geological strata with fossil remains and a waterfall • Series of ecological communities developed in response to sharply contrasting microclimates
Tompkins	• McLean Bogs	• Designated in 1973 • Two spring-fed bogs, one acidic and one alkaline • Rare plant species and one of the best examples of a northern deciduous forest in New York

Sources: ESRI 2010; NPS 2011f.

* None of the other NNLs in New York State, including those in Genesee, Onondaga, Seneca, and Ulster Counties, are located within the area underlain by the Marcellus and Utica Shales in New York

2.3.12.4 Additional Designated Scenic or Other Areas

This section discusses additional designated scenic or other areas that are considered visual resources or visually sensitive per NYSDEC Program Policy DEP-00-2, including sites, areas, lakes, reservoirs, or highways designated or eligible for designation as scenic; scenic areas of statewide significance; Adirondack Park scenic vistas; Palisades Park system components; and national heritage areas (NYSDEC 2000). These areas often contain scenic areas and/or are developed partly because of their associated visual or aesthetic qualities.

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)

Resources designated or eligible for designation as scenic can include sites, areas, lakes, reservoirs, or highways. Many of these types of resources are discussed in other areas of the Visual Resources section. This subsection focuses on designated scenic roads.

New York State Scenic Byways are transportation corridors that are of particular statewide interest. They are representative of a region's scenic, recreational, cultural, natural, historic, or archaeological significance (NYSDOT 1999-2011). There are nine state-designated and three proposed scenic byways within the area underlain by the Marcellus and Utica Shales in New York (see Table 2.99). The locations of many of these are shown on Figure 2.14. There are also a number of state-designated scenic roads in New York (NYSDOT 1999-2011). While there are 28 roads in portions of Orange and Greene Counties, these are all located outside the area underlain by the Marcellus and Utica Shales in New York.

The Great Lakes Seaway Trail, one of the state-designated scenic byways, is also a designated National Scenic Byway (Table 2.99 and Figure 2.14). The National Scenic Byways Program is managed by the U.S. Department of Transportation, Federal Highway Administration. National Scenic Byways are roads that are recognized based on one or more archaeological, cultural, historic, natural, recreational, and scenic qualities (USDOT 2011). State and national scenic byways and roads are resources designated specifically for scenic or aesthetic areas or qualities and which would be considered visual resources or visually sensitive.

Major Water Bodies
County Boundary
State Boundary
Boundary of Area of Interest for Visual Resources
State Scenic Byway
National Scenic Byway
Scenic Areas of Statewide Significance

Figure 2.14: Additional Designated Scenic or other Areas that May be Visually Sensitive

Source: ESRI, 2010; USGS, 2002; NYDEC, 2010; NPS, 2011; National Atlas US and USGS, 2010

Table 2.99 - Designated and Proposed National and State Scenic Byways, Highways, and Roads Located within the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

Name	Description
Great Lakes Seaway Trail	• National Scenic Byway • State-designated scenic byway • Great Lakes/Canadian border • Scenic, recreational, historic, and natural themes
Western New York Southtowns Scenic Byway	• State-designated scenic byway • Lake Erie • Scenic, historical, natural, recreational themes
Cayuga Lake Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic and recreational themes
Scenic Route 90	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, recreational, natural, and historic themes
Route 417/36 Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, recreational, natural, and historical themes
Seneca Lake, Hector and Lodi Scenic Byway	• State-designated scenic byway • Finger Lakes region of New York State • Scenic, historical, recreational, and natural themes
Route Twenty Scenic Byway (U.S. Route 20)	• State-designated scenic byway • Central New York State • Scenic, natural and historic themes
Shawangunk Mountains Scenic Byway*	• State-designated scenic byway • Shawangunk Mountains • Scenic and natural themes
Route 28 Central Catskills Scenic Byway	• Proposed scenic byway • Catskill Mountains
Mountain Cloves Scenic Byway	• Proposed scenic byway • Catskill Mountains
Durham Valley Scenic Byway	• Proposed scenic byway • Catskill Mountains
Upper Delaware Scenic Byway	• State-designated scenic byway • Delaware River Valley • Scenic, natural, historic, and recreational themes

Sources: NYSDOT 1999-2011; USDOT 2011; Catskill Center for Conservation and Development 2011; Durham Valley Scenic Byway Corridor Coordinating Committee (undated); Mountain Cloves Scenic Byway Steering Committee 2011.

* Shawangunk Mountains Scenic Byway is adjacent to and immediately outside of the western edge of the area underlain by the Marcellus and Utica Shales in New York.

Scenic Areas of Statewide Significance (Article 42 of Executive Law)

Scenic Areas of Statewide Significance (SASS) are areas designated by the Department of State based on a scenic assessment program developed by the Division of Coastal Resources. This program identifies the scenic qualities of coastal landscapes, evaluates them against criteria for determining aesthetic significance, and recommends areas for designation. An SASS designation protects scenic landscapes through the review of projects requiring state or federal actions, including direct actions, permits, or funding (NYSDOS 2004).

Six areas within the Hudson River Valley coastal regions in Columbia, Greene, Dutchess, and Ulster Counties were designated as SASSs in 1993. All six of these areas are outside the area underlain by the Marcellus and Utica Shales in New York (Figure 2.14).

Adirondack Park Scenic Vistas (Adirondack Park Land Use and Development Map)

The Adirondack Park was created in 1892 by the State of New York and is the largest publicly protected area in the contiguous United States. The boundary of the Park encompasses approximately 6 million acres in northern New York State, including portions of Saint Lawrence, Franklin, Clinton, Lewis, Herkimer, Hamilton, Essex, Oneida, Fulton, Warren, Saratoga, and Washington Counties. Nearly half of the Adirondack Park is publicly-owned and belongs to the people of New York State; this public land is constitutionally protected to remain “forever wild” forest preserve (Adirondack Park Agency 2003). No Adirondack Park Scenic Vistas are located within the boundary of the area underlain by the Marcellus and Utica Shales in New York (State of New York 2001).

Palisades Park (Palisades Interstate Park Commission)

The Palisades are a unique geological feature consisting of cliffs extending from southeastern New York State to northwestern New Jersey. While there is no Palisades Park in New York State, there are a number of state, county, and town parks in Orange and Rockland Counties, New York, that are located along the Palisades, many of which are operated in conjunction with the Palisades Interstate Park Commission. These parks include: Bear Mountain Park, Blauvelt State Park, Bristol Beach Park, Buttermilk Falls County Park, Clausland Mountain County Park, Franny Reese State Park, Goosepond Mountain Park, Harriman Park, Haverstraw Park, High Tor State Park, Highland Lakes Park, Hook Mountain State Park, Lake Superior Park, Minnewaska

Preserve, Mountain View Nature County Park, Nyack Beach State Park, Rockland Lake State Park, Schunnemunk Ridge Park, Sean Hunter Ryan Memorial County Park, Sterling Forest Park, Storm King Mountain Park, Tackamack Town Park (North and South), and Tallman State Park (New York-New Jersey Trails Conference 1999-2011, Palisades Parks Conservancy 2003-2007). None of these parks are located within the area underlain by the Marcellus and Utica Shales in New York.

Bond Act Properties purchased under Exceptional Scenic Beauty or Open Space category
Bond Act Properties are properties purchased under the "Exceptional Scenic Beauty" or "Open Space" categories of the Environmental Bond Act of 1986. Properties included in the "Exceptional Scenic Beauty" category are defined as land forms, water bodies, geologic formations, and vegetation that possess significant scenic qualities or significantly contribute to scenic value. Properties included in the "Open Space" category are defined as open or natural land in or near urban or suburban areas necessary to serve the scenic or recreational needs thereof. Such properties are purchased by individual municipalities using grants from New York State; grants consist of moneys raised through the sale of environmental bonds. Municipalities can include cities; counties, towns, villages, and public benefit corporations; school districts or improvement districts within a city, county, town or village; or Indian tribes residing within New York state; or any combination thereof (FindLaw 2011).

The OPRHP's Open Space Conservation Plan identifies 38 regional priority conservation projects within the area underlain by the Marcellus and Utica Shales in New York (Table 2.100). These projects represent the unique and irreplaceable open-space resources that encompass exceptional ecological, wildlife, recreational, scenic, and historical values. They were identified as a result of extensive analysis of New York State's open-space conservation needs by nine Regional Advisory Committees, in consultation with NYSDEC and OPRHP (OPRHP 2009). If acquired, these projects would be considered Bond Act properties purchased under the Open Space category. Additional previous Bond Act Properties may be located throughout the counties located entirely or partially within the area underlain by the Marcellus and Utica Shales in New York. Bond Act Properties purchased under the "Exceptional Scenic Beauty" or "Open Space" categories contain, or may contain, scenic or aesthetic qualities that may be considered visual resources or visually sensitive.

Table 2.100 - Recommended Open Space Conservation Projects Located in the Area Underlain by the Marcellus and Utica Shales in New York (New August 2011)

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
Albany**	3	• Black Creek Marsh/Vly Swamp (Project 44) – expand protection of wetland complex • Five Rivers Environmental Education Center (Project 46) – protect Phillipinkill stream corridor to north and east of education center • Helderberg Escarpment (Project 48) – protect southern extent of this natural feature
Allegany	1	• Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Cattaraugus	3	• Allegheny River Watershed (Project 117) – protect areas for conservation, recreational, educational, and public access purposes • Cattaraugus Creek and Tributaries (Project 119)*** – protect fisheries, recreational access, and unique geological areas • Significant wetlands (Project 127)*** – protect significant natural wetland communities and provide recreational, educational, and ecological enhancement opportunities (e.g., Keeney Swamp, Bird Swamp, and Hartland Swamp)
Cayuga**	2	• Carpenter Falls/Bear Swamp Corridor (Project 91)*** – protect water quality, preserve scenic resources, and expand the trail system in Bear Swamp State Forest • Summerhill Fen and Forest Complex (Project 102) – secure upland forests, wetlands, and adjacent upland buffers along Fall Creek that are recognized for biological and recreational significance
Chautauqua	5	• Cattaraugus Creek and Tributaries (Project 119)*** – protect fisheries, recreational access, and unique geological areas • Chautauqua Lake Access, Vistas, Shore Lands and Tributaries (Project 120) – secure public access for recreational fishing and boating, preserve undeveloped shoreline, and protect water quality • Lake Erie Tributary Gorges (Project 125)*** – acquire public access to various gorges along tributaries to Lake Erie • Trails and Trailways (Project 126) – protect existing trail corridors and acquire new corridor for trails • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Chemung	2	• Catharine Valley Complex (Project 108) – preserve unique geological and ecological areas and acquire land for recreational use of historic Chemung Canal towpath • Chemung River Greenbelt (Project 109)*** – expand and enhance significant recreational resources in a unique scenic landscape and protect important wildlife habitat
Chenango	1	• Genny Green Trail/Link Trail (Project 94) – acquire land for major trail connections
Cortland	1	• Develop a State Park in Cortland County (Project 92) – develop a state park

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
Delaware	3	• Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main Stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area, and Meade Hill/Fleischmann Mountain) • Upper Delaware Highlands (Project 42)*** – provide contiguous natural resource protection for one of key remaining ecological regions in the continental U.S through easements for forestland and farmlands and along the Upper Delaware Scenic Byway. • Susquehanna River Valley Corridor (Project 53)*** - protect areas within the Chesapeake Bay drainage basin for water quality, fisheries, public recreation, public access, birding, and agricultural conservation
Erie**	2	• Buffalo River Watershed (Project 118)*** – protect the Buffalo River corridor and three of its tributaries and improve access for recreational users • Lake Erie Tributary Gorges (Project 125)***– acquire public access to various gorges along tributaries to Lake Erie
Livingston**	2	• Genesee River Corridor (Project 107)*** – protect various habitats and landscapes along the Genesee River • Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113)*** - protect Finger Lakes shorelines that are wholly or largely undeveloped
Madison**	2	• Nelson Swamp (Project 95) – reduce ownership fragmentation of swamp, protect biologically significant swamp, further management objective of perpetual protection, and enhance compatible public use opportunities • Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Oneida**	1	• Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison and Onondaga Counties)
Onondaga**	2	• Camillus Valley/Nine Mile Creek (Project 90) – buffer important attributes of the Nine Mile Creek Valley from development and provide public waterway access • Carpenter Falls/Bear Swamp Corridor (Project 91)*** – protect water quality, preserve scenic resources, and expand the trail system in Bear Swamp State Forest
Ontario**	2	• Hi Tor/Bristol Hills (Project 110)*** – ensure that key tracts of land remain as open space in this area • Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113)*** - protect Finger Lakes shorelines that are wholly or largely undeveloped • Wolf Gully (Project 114) – protect for its exceptional biological diversity
Orange**	1	• Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area and Meade Hill/Fleischmann Mountain)
Otsego**	2	• Susquehanna River Valley Corridor (Project 53)*** - protect areas within the Chesapeake Bay drainage basin for water quality, fisheries, public recreation, public access, birding and agricultural conservation

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
		• Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Schoharie**	1	• Central Leatherstocking – Mohawk Grasslands Area (Project 87)*** – multi-regional project for conservation of habitat for grassland birds (grasslands occur in portions of Schoharie, Otsego, Oneida, Madison, and Onondaga Counties)
Seneca**	1	• Seneca Army Depot Conservation Area (Project 111) – protect a unique population of white deer
Steuben	1	• Chemung River Greenbelt (Project 109)*** – expand and enhance significant recreation resources in a unique scenic landscape and protect important wildlife habitat
Sullivan**	4	• Neversink Highlands (Project 28) – protect significant natural attractions and resources, hunting and fishing opportunities, and wildlife habitat in the following areas: Tomsco Falls, Neversink Gorge vicinity, Basha Kill vicinity and Harlen Swamp Wetland Complex • Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area and Meade Hill/Fleischmann Mountain) • New York City Watershed Lands (Project 39) – identify and protect high-priority sites on land that have potential for development, for forestry, or for fisheries and relatively large and/or link area already protected by private or public entities and/or allow for improved long-term management of land and water resources • Upper Delaware Highlands (Project 42)*** – provide contiguous natural resource projection for one of key remaining ecological regions in the continental U.S through easements for forestland and farmlands and along the Upper Delaware Scenic Byway
Tioga	2	• Two Rivers State Park (Project 103) – develop a state park • Emerald Necklace (Project 104) – consolidate existing state holdings while ensuring linkage between public land in the vicinity of Ithaca, conserve lands, and enhance recreational opportunities
Tompkins	2	• State Parks Greenbelt/Tompkins County (Project 101) – protect valuable open-space recreational resources between four state park facilities connected by the Black Diamond Trail Corridor • Finger Lakes Shorelines (Project 105) – preserve portions of the shoreline of the Finger Lakes for public access or wildlife in the following areas or projects: Finger Lakes Water Trails, Owasco Flats, Camp Barton, On Cayuga Lake, B&H Railroad property at the south end of Keuka Lake in Hammondsport, extending the eastern terminus of the Outlet Trail to the Seneca Lake shoreline at Dresden, and undeveloped shoreline on Seneca Lake
Ulster**	3	• Great Rondout Wetlands (Project 24) – protect several large wetlands in the following areas: Great Pacama Vly, Cedar Swamp and Beer Kill Wetlands/Cape Pond • Catskill River and Road Corridors (Project 36)*** – protect lands that serve as riparian buffers, preserve or restore floodplain areas, protect scenic areas and vistas along principal road corridors and on visible ridgelines, protect flood-prone areas, and enhance public access and recreational opportunities in the following areas: Beaverkill/Willowemoc/Route 17 (future Interstate 86) Corridor; Delaware River Branches and Main-stem Corridors; Mongaup Valley WMA; and Route 28 Corridor (Blue Stone Wild Forest, Ticeteneyck Mt./Tonshi Mt./Kenozia Lake, Catskill Interpretive Center area, and Meade Hill/Fleischmann Mountain)

County Name*	Number of Recommended Conservation Projects in County	Name of Recommended Conservation Project
		• Catskills Unfragmented Forest (Project 37) – securing additional large unfragmented areas of forestlands in the Catskill High Peaks areas, including the following sites : Overlook Mountain; Guardian Mountain; Indian Head Wilderness Consolidation; Balsam, Graham and Doubletop Mountains/Dry Brook Valley; Peekamoose Gorge; Frost Valley; Fir Brook/Round Pond/Black Bear Road Vicinity; West Shokan/Sampsonville Area Lands; Bearpen/Vly/Roundtop Mountains; Catskill Escarpment North and Windham High Peak; Rusk Mountain Wild Forest; Hunter West Kill Wilderness; and Catskill Mountain Heritage Trail
Wyoming	3	• Buffalo River Watershed (Project 118)*** – protect the Buffalo River corridor and three of its tributaries and improve access for recreational users • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities • Inland Lakes (Project 124)*** – protect undeveloped shoreline associated with wetlands and critical tributary habitat; protect water quality and important fish and wildlife habitat; and secure adequate public access for recreational opportunities
Yates	1	• Hi Tor/Bristol Hills (Project 110)*** – ensure that key tracts of land remain as open space in this area
Total	38***	

Source: OPRHP 2009.

* No other recommended conservation projects are located within the area underlain by the Marcellus and Utica Shales in New York.

** Only a portion of the county is located within the area underlain by the Marcellus and Utica Shales.

*** Susquehanna River Valley Corridor (Project 53) is in two counties (Otsego and Delaware); Cattaraugus Creek and Tributaries (Project 119) is in two counties (Cattaraugus and Chautauqua); Carpenter Falls/Bear Swamp Corridor (Project 91) may be in two counties (Cayuga and Onondaga); Lake Erie Tributary Gorges (Project 125) may be in two counties (Chautauqua and Erie); Central Leatherstocking – Mohawk Grasslands Area (Project 87) may occur in multiple counties (Schoharie, Otsego, Oneida, Madison and Onondaga); Catskill River and Road Corridors (Project 36) may occur in multiple counties (Delaware, Sullivan, Orange and Ulster); Catskill River and Road Corridors (Project 36) may occur in two counties (Delaware and Sullivan); Buffalo River Watershed (Project 118) will occur in two counties (Erie and Wyoming); Genesee River Corridor (Project 107) may occur in multiple counties from the New York/Pennsylvania state line to Lake Ontario; Western Finger Lakes: Conesus, Hemlock, Canadice and Honeoye (Project 113) will occur in two counties (Livingston and Ontario); Chemung River Greenbelt (Project 109) will occur in two counties (Chemung and Steuben); Inland Lakes (Project 124) is in three counties (Allegany, Chautauqua, and Wyoming); Hi Tor/Bristol Hills (Project 110) is in two counties (Yates and Ontario); Significant wetlands (Project 127) may occur in numerous counties.

2.3.13 Noise[47]

2.3.13.1 Noise Fundamentals

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, and so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities. The unit of noise measurement is a decibel

[47] Subsection 2.4.13, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

(dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as dBA (A-weighted decibels). (“A” indicates that the sound has been filtered to reduce the strength of very low and very high frequency sounds, much as the human ear does.) The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans do not perceive a 10-dBA increase as 10 times louder but as only twice as loud.

The following is typical of human responses to changes in noise level:

- A 3-dBA change is the threshold of change detectable by the human ear;
- A 5-dBA change is readily noticeable; and
- A 10-dBA change is perceived as a doubling (or halving) of noise level.

The decrease in sound level from any single noise source normally follows the “inverse square law.” That is, sound pressure level (SPL) changes in inverse proportion to the square of the distance from the sound source. At distances greater than 50 feet from a sound source, every doubling of the distance produces a 6-dB reduction in the sound level. Therefore, a sound level of 70 dB at 50 feet would have a sound level of approximately 64 dB at 100 feet. At 200 feet, sound from the same source would be perceived at a level of approximately 58 dB.

The total sound pressure created by multiple sound sources does not create a mathematical additive effect. For example, two proximal noise sources that are 70 dBA each do not have a combined noise level of 140 dBA. In this case the combined noise level is 73 dBA. As the difference between the two sound levels is 0 dB, 3 dB are added to the sound level to compensate for the additive effects of the sound.

To characterize the average ambient noise (“noise”) environment in a given area, noise level descriptors are commonly used. The Leq (sound level equivalent) is generally used to characterize the average sound energy that occurs during a relatively short period, such as an hour. The Ldn (day-night level) would be used for an entire 24-hour period. To account for peoples’ greater sensitivity to sound during nighttime hours, the Ldn noise metric descriptor places a stronger emphasis on noise that occurs during nighttime hours (10 p.m. to 7 a.m.) by applying a 10-dB "penalty" to those hours. The Lmax refers to the maximum A-weighted noise level recorded for a single noise event during a given period.

Although both the sound power and sound pressure characteristic of sound share the same unit of measure, the decibel (dB), and the term "sound level" is commonly substituted for each, they have different properties. Sound power is the acoustical energy emitted by the sound source, and is an absolute value; it is not affected by the environment. The SPL is the varying difference, at a fixed point, between the pressure caused by a sound wave and atmospheric pressure. Sound pressure is what our ears hear and what sound level meters measure. The sound power level is always considerably higher than the sound pressure level near a source because it takes into account the effective radiating surface area of the source.

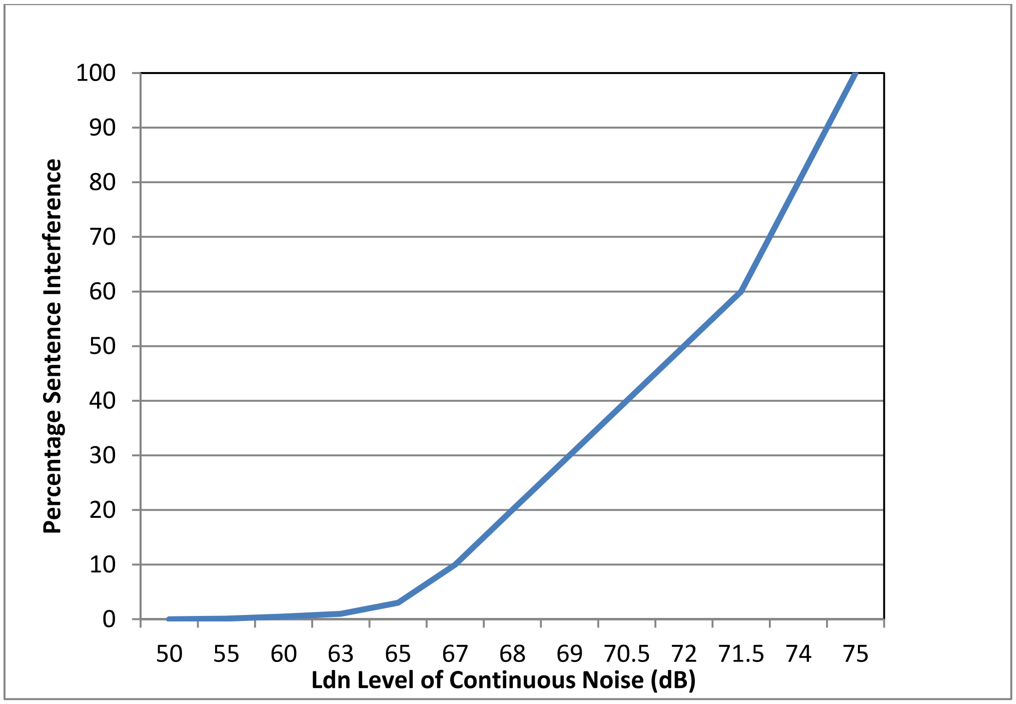
2.3.13.2 Common Noise Effects

Common noise effects include speech interference, sleep disturbance, and annoyance.

Speech Interference

The interference with speech comprehension is a masking process in which environmental noise curtails or prevents speech perception. The United States Environmental Protection Agency (USEPA) established the relationship between percent speech intelligibility and continuous noise level (USEPA 1974). This relationship is presented in Figure 2.15

Figure 2.15 - Level of Continuous Noise Causing Speech Interference (New August 2011)



Source: USEPA 1974.

Sleep Disturbance

Exposure to noise can produce disturbances of sleep in terms of difficulty to fall asleep, alterations of sleep pattern and depth, and awakening. It should be noted that the adverse effect of noise on sleep partly depends on the nature of the noise source, and there are considerable differences in individual reactions to the same noise. To avoid sleep disturbance, the World Health Organization (WHO) recommends an indoor level in bedrooms of 30 dBA for continuous noise and an Lmax of 45 dBA for single sound events (WHO 2000).

Annoyance

The capacity of noise to induce annoyance depends upon many of its physical characteristics, including its SPL and spectral characteristics, as well as the variations of these properties over time. Numerous studies have been conducted to assess community annoyance in response to transportation noise sources. A summary of community annoyance is presented in Table 2.101.

Table 2.101 - Effects of Noise on People (New August 2011)

Ldn (dBA)	**Percent Annoyance**	**Average Community Reaction**	**General Community Attitude Towards Area**
≥ 75	37	Very Severe	Noise is likely to be the most important of all adverse aspects of the community environment.
70	22	Severe	Noise is one of the most important adverse aspects of the community environment.
65	12	Significant	Noise is one of the important adverse aspects of the community environment.
60	7	Moderate	Noise may be considered an adverse aspect of the community environment.
≤ 55	3	Slight	Noise is considered no more important than various other environmental factors.

Source: Cowan 1994.

2.3.13.3 Noise Regulations and Guidance

Federal

In 1974 the USEPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety* (USEPA 1974). This publication evaluates the effects of environmental noise with respect to health and safety. The document provides information for state and local governments to use in developing their own ambient noise standards. The USEPA has determined that in order to protect the public from activity interference and annoyance outdoors in residential areas, noise levels should not exceed an Ldn of 55 dBA (Table 2.102). The USEPA considers an Ldn of 55 dBA to be the maximum sound level that will not adversely affect public health and welfare by interfering with speech or other activities in outdoor areas.

Table 2.102 - Summary of Noise Levels Identified as Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety (New August 2011)

Effect	Level	Area
Hearing Loss	$\text{Leq}_{(24)}$ =< 70 dB	All areas
Outdoor activity interference and annoyance	Ldn =< 55 dB	Outdoors in residential areas and farms and other outdoor areas where people spend widely varying amounts of time and other places in which quiet is a basis for use
	$\text{Leq}_{(24)}$ =< 55 dB	Outdoor areas where people spend limited amounts of time, such as school yards, playgrounds, etc.
Indoor activity interference and annoyance	Ldn =< 45 dB $\text{Leq}_{(24)}$ =< 45 dB	Indoor residential areas Other indoor areas with human activities such as schools, etc.

Source: USEPA 1974.

New York State

The Department has issued Program Policy DEP-00-1, Assessing and Mitigating Noise Impacts, which is intended to provide direction to Department staff for the evaluation of sound levels and characteristics generated from proposed or existing facilities. Under this policy, in the review of an application for a permit, the Department is to evaluate the potential for adverse impacts of sound generated and emanating to receptors outside of the facility or property. When a sound level evaluation indicates that receptors may experience sound levels or characteristics that produce significant noise impacts or impairment of property use, the Department is to require the permittee or applicant to employ reasonable and necessary measures to either eliminate or mitigate adverse noise effects.

In the Department policy, 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. SPL, or perceived loudness, as expressed in decibels (dB) or A-weighted decibel scale dBA, 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.

The initial evaluation for most facilities should determine the maximum amount of sound created at a single point in time by multiple activities for the proposed project. All facets of the construction and operation that produce noise should be included, such as land-clearing activities (chain saw and equipment operation), drilling, equipment operation for excavating, hauling or conveying materials, pile driving, steel work, material processing, and product storage and removal. Land clearing and construction may be only temporary noise at the site, whereas the ongoing operation of a facility would be considered permanent noise.

The Department Noise Guidelines state that increases ranging from 0 to 3 dB will have no appreciable effect on receptors, and that increases from 3 to 6 dB have potential for adverse noise impact only in cases where the most sensitive receptors are present. Sound pressure increases of more than 6 dB may require additional analysis of impact potential, depending on existing sound pressure levels and the character of surrounding land uses and receptors, and an increase of 6 dB(A) may cause complaints. Therefore, a cumulative increase in the total ambient sound level of 6 dBA or less is unlikely to constitute an adverse community impact.

To aid staff in its review of a potential noise impact, Program Policy DEP-00-1 identifies three major categories of noise sources:

- Fixed equipment or process operations,
- Mobile equipment or process operations, and
- Transport movements of products, raw material or waste.

2.3.13.4 Existing Noise Levels

The ambient sound level of a region is defined by the total noise generated, including sounds from natural and man-made sources. The magnitude and frequency of environmental noise may vary considerably over a day and throughout the week because of changing weather conditions and the effects of seasonal vegetative cover. Table 2.103 presents SPLs that are characteristic for the land use described. Most of the high-volume hydraulic fracturing would occur in quiet rural areas where the noise levels are typically as low as 30 dBA, depending on weather conditions and natural noise sources.

Table 2.103 - Common Noise Levels (New August 2011)

Description	**SPL (dBA)**
Rural area at night	30
Quiet suburban area at night	40
Typical suburban area	50
Typical urban area	60

Source: Cowan 1994.
SPL = sound pressure level.

2.3.14 Transportation - Existing Environment[48]

This section presents a general overview of the vehicle and road classification system, major roadways and roadway use in the regional areas, and the primary funding sources for the roadway improvements. Although roadways would be the primary transportation system used to access well sites, railroads and airports may also be used to transport equipment and supplies. These other transportation modes are also briefly discussed.

2.3.14.1 Terminology and Definitions

The following terms are defined at the federal level to describe roadway classifications and vehicle classes and are used by transportation planners and engineers at the state and local levels.

[48] Subsection 2.4.14, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

Federal Functional Classification Codes

The federal functional classification (FC) codes group streets, roads, and highways into several classes based on the construction type and the type of service the roads provide. This discussion focuses on the roads prevalent in rural areas, where most of the horizontal drilling and high-volume hydraulic fracturing is assumed to occur.

Rural areas have five basic classifications of roads:

- FC01/FC02 - Principal Arterial (Interstate or Other);
- FC06 - Minor Arterial;
- FC07 – Major Collector;
- FC08 – Minor Collector; and
- FC09 – Local.

Typically, the higher the road classification, the higher the level of service a road can supply to vehicles, whether measured by vehicle class/weight or number of vehicle trips.

The arterial system of roadways provides the highest level of mobility at the highest speed, for long, uninterrupted travel. The construction of roads in the arterial system follows stringent guidelines, and high-grade materials are used. These roads can support more of the heavy vehicle truck traffic than smaller, local roads. The minor collectors (FC08) and, to a larger extent, the local roads (FC09) show signs of deterioration with an increase in heavy-truck traffic.

- Principal Arterial. The Principal Arterial categories are often divided into Principal Arterial - Interstate, and Principal Arterial - Other. Arterials generally are constructed according to higher design standards than other roads, often have multiple lanes traveling in the same direction, and have some degree of access control, such as on ramps.

  The rural principal arterial highway network is an interstate and inter-county roadway that connects developed areas with an urban population typically greater than 50,000 people.

- Minor Arterial. A rural minor arterial highway is a roadway that is considered serving an urban area if it comes within 2 miles of the urban boundary.

Collector roadways provide a lower degree of mobility than arterials and are not designed for long-distance or high-speed travel. They typically consist of two-lane roads that collect and distribute traffic from the arterial system. They are divided into two categories in the rural setting - Major Collectors and Minor Collectors.

- Major Collector. Major Collectors provide service to any county seat not on an arterial route and can also connect or serve larger towns that are not provided services by their arterial roads.

- Minor Collector. Minor Collectors are roadways that are spaced consistently and proportional to population densities present in the rural community. They collect traffic from local roads and provide access to higher-level roads.

Local roads are the largest category of roads in terms of mileage in the road network. In rural areas, they include all public roads below the collector system, including basic residential and commercial roads.

There is an inverse relationship between the speeds and distances traveled on roads versus the actual existing mileage of the various road systems. The arterial systems account for higher average vehicle miles per trip (VMT), while local road systems account for the vast majority of actual roads (Table 2.104).

Table 2.104 - Guidelines on Extent of Rural Functional Systems (New August 2011)

System	**Range (Average Vehicle Miles per Trip [VMT])**	**Miles of Road (percent)**
Principal Arterial System	30-55	2-4
Principal Arterial plus Minor Arterial Road System	45-75	6-12[1]
Collector Road System	20-35	20-25
Local Road System	5-20	65-75

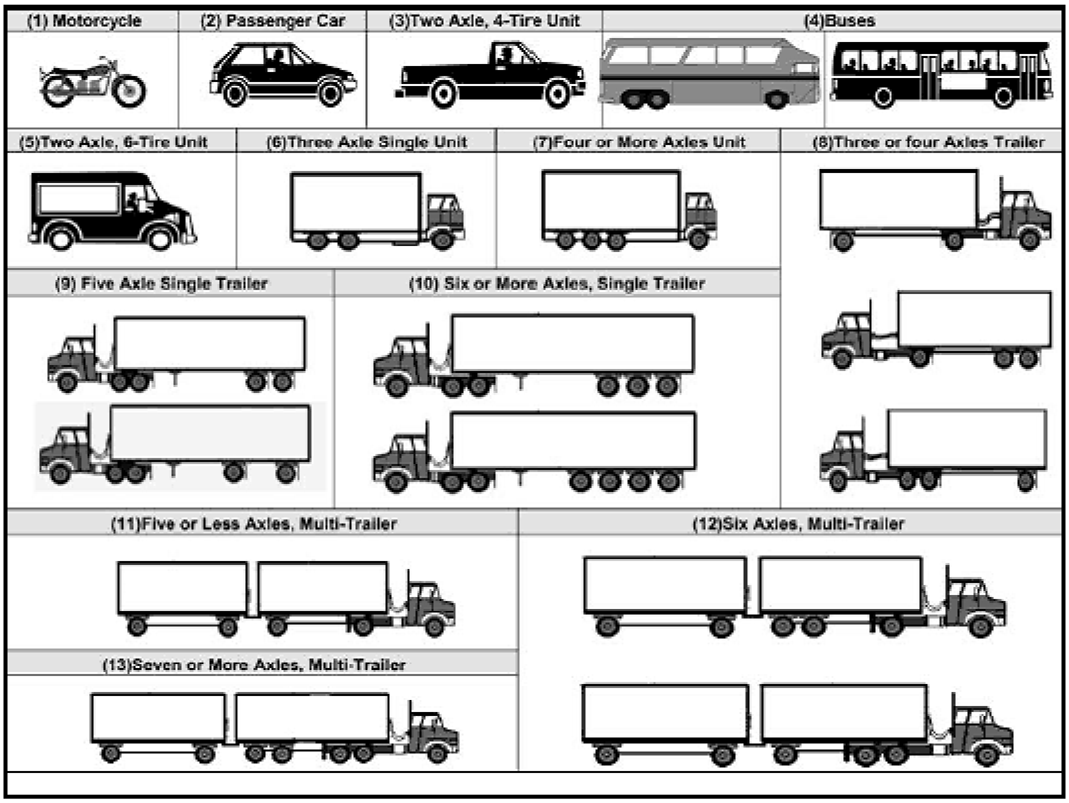
Source: FHWA 2011.
[1] Most states fall in the 7-10% range.

The FC codes have recently been updated; however, the codes presented in this section correspond to the codes used in data compilations that are currently available.

FHWA Vehicle Classes with Definitions

Figure 2.16 presents the Federal Highway Administration's (FHWA) vehicle class definitions (FHWA 2011). Table 2.105 provides descriptions of the 13 vehicle classes designated by the FHWA.

Figure 2.16 - FHWA Vehicle Classifications (New August 2011)



Source: Diamond Traffic Products 2011.

Table 2.105 - Descriptions of the Thirteen FHWA Vehicle Classification Categories (New August 2011)

Vehicle Class	Description
1	**Motorcycles**. All two- or three-wheeled motorized vehicles. Typical vehicles in this category have saddle-type seats and are steered by handlebars rather than steering wheels. This category includes motorcycles, motor scooters, mopeds, motor-powered bicycles, and three-wheel motorcycles. This vehicle type may be reported at the option of the state.
2	**Passenger Cars.** All sedans, coupes, and station wagons manufactured primarily for the purpose of carrying passengers and including those passenger cars pulling recreational or other light trailers.
3	**Other Two-Axle, Four-Tire Single Unit Vehicles.** All two-axle, four-tire vehicles other than passenger cars. Included in this classification are pickup and panel trucks, vans, and other vehicles such as campers, motor homes, ambulances, hearses, carryalls, and minibuses. Other two-axle, four-tire single-unit vehicles pulling recreational or other light trailers are included in this classification. (**Note:** Because automatic vehicle classifiers have difficulty distinguishing class 3 from class 2, these two classes may be combined into class 2).
4	**Buses.** All vehicles manufactured as traditional passenger-carrying buses with two axles and six tires or three or more axles. This category includes only traditional buses (including school buses) functioning as passenger-carrying vehicles. Modified buses should be considered to be a truck and should be appropriately classified.
5	**Two-Axle, Six-Tire, Single-Unit Trucks.** All vehicles on a single frame, including trucks, camping and recreational vehicles, motor homes, etc., with two axles and dual rear wheels.
6	**Three-Axle, Single-Unit Trucks**. All vehicles on a single frame, including trucks, camping and recreational vehicles, motor homes, etc., with three axles.
7	**Four or More Axle, Single-Unit Trucks.** All trucks on a single frame with four or more axles.
8	**Four or Fewer Axle, Single-Trailer Trucks.** All vehicles with four or fewer axles, consisting of two units, one of which is a tractor or straight truck power unit.
9	**Five-Axle, Single-Trailer Trucks**. All five-axle vehicles consisting of two units, one of which is a tractor or straight truck power unit.
10	**Six or More Axle, Single-Trailer Trucks.** All vehicles with six or more axles, consisting of two units, one of which is a tractor or straight truck power unit.
11	**Five or Fewer Axle, Multi-Trailer Trucks**. All vehicles with five or fewer axles, consisting of three or more units, one of which is a tractor or straight truck power unit.
12	**Six-Axle, Multi-Trailer Trucks.** All six-axle vehicles consisting of three or more units, one of which is a tractor or straight truck power unit.
13	**Seven or More Axle, Multi-Trailer Trucks.** All vehicles with seven or more axles, consisting of three or more units, one of which is a tractor or straight truck power unit.

Source: FHWA 2001.

Notes: In reporting information on trucks, the following criteria should be used:

- Truck tractor units traveling without a trailer will be considered single-unit trucks.
- A truck tractor unit pulling other such units in a “saddle mount” configuration will be considered one single-unit truck and will be defined only by the axles on the pulling unit.
- Vehicles are defined by the number of axles in contact with the road. Therefore, “floating” axles are counted only when in the down position.
- The term “trailer” includes both semi- and full trailers.

Not included in the FHWA Vehicle Classification Categories are farm and agricultural equipment, which are common in the rural areas. Many of the rural roads are shared by passenger traffic, truck traffic, and farm and agricultural equipment.

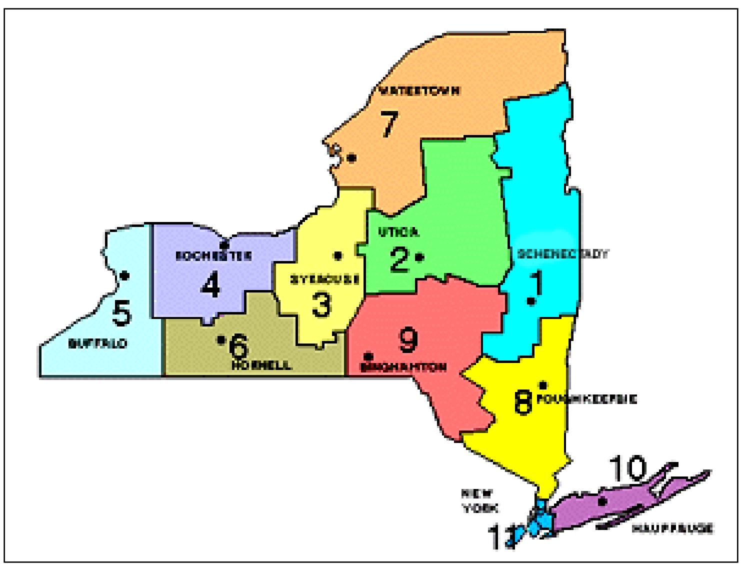
2.3.14.2 Regional Road Systems

New York State

The NYSDOT, acting through the Commissioner of Transportation, has general supervision of roads, highways, and bridges in the State of New York. The functions, powers and duties of the Commissioner of Transportation and the NYSDOT, respectively, are more fully described in Article II of the Highway Law and Article 2 of the Transportation Law. It is the mission of the NYSDOT to ensure that those who live, work, and travel in New York State have a safe, efficient, balanced, and environmentally sound transportation system.

The NYSDOT is divided into 11 regions to better manage the roadways, duties, and users (Figure 2.17).

Figure 2.17 - New York State Department of Transportation Regions (New August 2011)



Source: NYSDOT 2011a

The network of roads within New York State consists of federal, state, county, local, and private roads. Overall, there are an estimated 114,546 miles of highway roads in the state. This includes 32 interstate highways (principal arterials) totaling 1,705 miles, which are primarily maintained by the NYSDOT.

Figure 2.18 depicts the main interstate highways in New York State. The New York State Thruway, also known as the Governor Thomas E. Dewey Thruway (Interstate (I-) 90) is the main east-west route that crosses the midsection of the state, linking Buffalo, Rochester, Syracuse, and Albany. The New York State Thruway is a system of limited-access highways in New York State operated by the New York State Thruway Authority (NYSTA). It includes a total of approximately 570 miles (that is comprised of portions of I-87, I-90, I-95, I-190, and I-287). The Southern Tier Expressway, I-86, also is a major east-west route that services that southern portion of the state, connecting Jamestown, Olean, Elmira, and Binghamton. From Binghamton, I-86 runs southeast, providing access to New York City, and I-88 runs northeast providing access to Albany. Major north-south routes include I-81, which extends from Pennsylvania north through Binghamton and Syracuse to the border crossing with Canada, and I-87, which extends from New York City north to Montreal.

The state's transportation and road network also includes over 15,000 miles of state routes and 97,000 miles of county and local roads (NYSDOT 2009a). Each region examined as part of this analysis is discussed individually below.

The NYSDOT has specific, statutory authority to regulate work within the state highway rights-of-way (ROWs) (see Highway Law Section 52). This authority extends to granting, conditioning, or denying permits for, among many other things, curb cuts or breaks in access to state highways, utility work within the state ROWs that would be necessary for the operation of hydraulic fracturing facilities, and design approval for any new culverts, bridges, access roads, etc., on state ROWs that may become necessary for the construction or operation of hydraulic fracturing facilities.

Region A

Region A comprises Chemung, Tioga, and Broome Counties, which are within NYSDOT Regions 6 (Chemung) and 9 (Tioga and Broome). Table 2.106 presents a summary of the mileage of highways within each county. The Highway Mileage Report developed by NYSDOT provides current information on the public highway mileage in New York State by county (NYSDOT 2009a).

City with Year 2000 Population Greater than 25,000

Commercial Airports

Railroad

Interstate

County Boundary

State Boundary

Figure 2.18: Transportation

Source: ESRI, 2010; USGS, 2002

Table 2.106 - Region A: Highway Mileage by County, 2009 (New August 2011)

	Town or Village	County	NYSDOT Owned	Other	Total
Chemung	766.7	243.7	118.4	3.6	**1,132.4**
Tioga	823.7	141.7	155.2	0.0	**1,120.6**
Broome	1,340.1	339.1	297.3	19.6	**1,996.1**
Total Region A	**2,930.5**	**724.5**	**570.9**	**23.2**	**4,249.1**

Source: NYSDOT 2009a.

The principal arterial in Region A is the Southern Tier Expressway (I-86/NY-17), which runs east-west through the three counties that constitute Region A. This highway connects Elmira and areas west of the region with Binghamton and areas east of the region. Another major highway, I-81, intersects I-86 in Binghamton and runs north to Syracuse and south to Scranton, Pennsylvania. In addition, I-88 originates in Binghamton and runs northeast to Albany (Figure 2.18)

Numerous other arterials, collectors, and local roadways cover this region and connect smaller towns and villages. Heavy vehicles (i.e., Vehicle Classifications 04 through 13) primarily use major roadways. NYSDOT conducted a study of the road use by heavy vehicle traffic, based on 2004 to 2009 data (NYSDOT 2010a). The data for rural areas in NYSDOT Regions 6 and 9 are presented in Table 2.107.

Table 2.107 - Heavy Vehicles as a Percentage of Total Vehicles in Rural Areas in NYSDOT Regions 6 and 9, 2004-2009 (New August 2011)

Functional Classification (FC) Code	NYSDOT Region 6	NYSDOT Region 9	Statewide
01	36.0%	25.1%	25.2%
02	15.5%	13.6%	12.5%
06	10.2%	10.2%	9.5%
07	10.9%	8.7%	8.9%
08	5.7%*	6.8%	6.8%
09	-*	6.4%	7.1%

Source: NYSDOT 2010a.
* No data or insufficient data (i.e., data from <10 highway segments).

Heavy-vehicle traffic is concentrated on major roadways, with FC road classifications 01 and 02 handling 51.5% and 38.7%, respectively, of heavy-vehicle traffic in NYSDOT Regions 6 and 9. Compared to the statewide percentage (37.7%), in both Regions 6 and 9, heavy-vehicle traffic is concentrated more on principal arterial roadways and less on other roads. Since FC01 and FC02 are arterials used primarily for long-distance, high-speed travel, the majority of this traffic is assumed to pass through the counties.

Region B

Region B comprises Otsego, Delaware, and Sullivan Counties, all of which are in NYSDOT Region 9. Table 2.108 presents a summary of the mileage of highways within each county. The Highway Mileage Report developed by NYSDOT provides current information on the public highway mileage in New York State by county (NYSDOT 2009a).

Table 2.108 - Region B: Highway Mileage by County, 2009 (New August 2011)

	Town or Village	**County**	**NYSDOT Owned**	**Other**	**Total**
Otsego	1,326.2	476.6	290.4	4.2	**2,097.4**
Delaware	1,608.4	262.0	341.1	37.5	**2,248.9**
Sullivan	1,462.1	385.3	201.9	10.6	**2,059.9**
Total Region B	**4,396.7**	**1,123.9**	**833.4**	**52.3**	**6,406.2**

Source: NYSDOT 2009a.

The road network in Region B has two main roadway corridors running through different sections of the three counties. One is I-88, which runs in a southwest-northeast direction along the border of Otsego and Delaware Counties. In addition, NY-17 runs from the western portion of Delaware County to the east and southeast, along the Catskill Forest Preserve, into Sullivan County and towards New York City (Figure 2.18).

Numerous other arterials, collectors, and local roadways cover this region and connect smaller towns and villages. Heavy vehicles primarily use major roadways. A NYSDOT study used vehicle classification data from 2004 to 2009 to estimate the percentage of heavy vehicles on various road classifications in rural and urban settings (NYSDOT 2010a). The data for rural areas in NYSDOT Region 9 are presented in Table 2.109.

Table 2.109 - Heavy Vehicles as a Percentage of Total Vehicles in Rural Areas in NYSDOT Region 9, 2004-2009 (New August 2011)

Functional Classification (FC) Code	NYSDOT Region 9	Statewide
01	25.1%	25.2%
02	13.6%	12.5%
06	10.2%	9.5%
07	8.7%	8.9%
08	6.8%	6.8%
09	6.4%	7.1%

Source: NYSDOT 2010a.

Heavy-vehicle traffic is concentrated on major roadways, with FC road classifications 01 and 02 handling 38.7% of heavy-vehicle traffic in NYSDOT Region 9. Compared to the statewide percentage (37.7%), in Region 9, heavy-truck traffic is concentrated more on principal arterials and a less on other roads.

Region C

Region C comprises Chautauqua and Cattaraugus Counties, both of which are in NYSDOT Region 5. Table 2.110 presents a summary of the mileage of highways in each county. The *Highway Mileage Report* developed by NYSDOT provides current information on the public highway mileage in New York State, by county (NYSDOT 2009a).

Table 2.110 - Region C: Highway Mileage by County, 2009 (New August 2011)

	Town or Village	County	NYSDOT Owned	Other	Total
Cattaraugus	1,379.8	397.7	315.2	54.1	**2,146.8**
Chautauqua	1,531.5	551.5	353.1	47.1	**2,483.2**
Total Region C	**2,911.3**	**949.2**	**668.3**	**101.2**	**4,630.0**

Source: NYSDOT 2009a.

The two main roadway corridors in Region C run through different sections of the two counties. One is I-90, which runs northeast from the Pennsylvania border in Chautauqua County and along Lake Erie towards Buffalo, New York. The other corridor, I-86/NY-17, runs east-west through both Chautauqua and Cattaraugus Counties, crossing into Pennsylvania in western Chautauqua County. I-86/NY-17 crosses over Chautauqua Lake and runs north of the major population center of Jamestown. It also connects other cities such as Randolph, Salamanca, and Olean (Figure 2.18).

Numerous other arterials, collectors, and local roadways cover this region and connect smaller towns and villages; these include Route 16, Route 19, Route 60, and Route 219. Heavy vehicles primarily use major roadways. A NYSDOT study used vehicle classification data from 2004 to 2009 to estimate the percentage of heavy vehicles on various road classifications in rural and urban settings (NYSDOT 2010a). The data for rural areas in NYSDOT Region 5 are presented in Table 2.111.

Table 2.111 - Heavy Vehicles as a Percentage of Total Vehicles in Rural Areas in NYSDOT Region 5, 2009 (New August 2011)

Functional Classification (FC) Code	NYSDOT Region 5	Statewide
01	23.5%	25.2%
02	10.9%	12.5%
06	11.3%	9.5%
07	8.8%	8.9%
08	6.3%	6.8%
09	7.1%	7.1%

Source: NYSDOT 2010a.

Heavy-vehicle traffic is concentrated on major roadways, with FC classifications 01 and 02 handling 34.4% of heavy-vehicle traffic in NYSDOT Region 5. However, the percentages are less than the corresponding statewide percentage. This may be a result of the city of Buffalo being located in NYSDOT Region 5, where heavy-vehicle traffic may use smaller roads in industrial/manufacturing areas for pickups and deliveries.

2.3.14.3 Condition of New York State Roads

New York State reports annually on the condition of bridges and pavements. Based on data submitted to the FHWA in April 2010, about 12% of the highway bridges in New York State are classified, under the broad federal standards, as structurally deficient, and about 25% are classified as functionally obsolete. Those classifications do not mean the bridges are unsafe, rather that they would require repairs or modifications to restore their condition or improve their functionality (NYSDOT 2011b).

The condition of pavements is scored on a 10-point scale, as shown in Table 2.112. New York State road conditions are ranked 42nd in the nation (NYSDOT 2009b). This makes any impacts on road conditions an important consideration.

Table 2.112 - Ranking System of Pavement Condition in New York State (New August 2011)

9-10	Excellent	No significant surface distress
7-8	Good Surface	Distress beginning to show
6	Fair	Surface distress is clearly visible
1-5	Poor	Distress is frequent and severe
U	Under Construction	Not rated due to ongoing work

Source: NYSDOT 2010b.

2.3.14.4 NYSDOT Funding Mechanisms

The construction, reconstruction, or maintenance (including repair, rehabilitation, and replacement) of transportation infrastructure under the State's jurisdiction are performed by the NYSDOT. The state has statutorily established a number of funds that collect dedicated taxes and fees to fund NYSDOT's capital and operating activities. Most of the tax and fee sources for these funds are related to transportation and collected from transportation users. They include:

- Petroleum business tax;
- Highway use tax;
- Motor fuel tax;
- Motor vehicle fees;
- Auto rental tax; and
- Miscellaneous special revenues.

The Petroleum Business Tax (PBT) is a tax imposed on petroleum businesses operating in New York State. The tax is paid by registered distributors and is imposed at a cents-per-gallon rate on petroleum products sold or used in the State. The tax imposition occurs at different points in the distribution chain, depending on the type of petroleum product: For motor fuel, the PBT is imposed upon importation into the State; for diesel motor fuel, the PBT is imposed on the first sale or use in the State; for non-automotive diesel fuel and residual oil, the PBT is imposed on final sale or use; for kero-jet fuel, the PBT is imposed on fuel consumed on take-off from points in the State. The tax is jointly administered and collected with the State's motor fuel tax (NYSDTF 2011a).

The Highway Use Tax (HUT) is a tax on motor carriers operating certain motor vehicles on New York State public highways (excluding toll-paid portions of the New York State Thruway). The tax is based on mileage traveled on NYS public highways and is computed at a rate determined by the weight of the motor vehicle and the reporting method. A HUT certificate of registration is required for any truck, tractor, or other self-propelled vehicle with a gross weight over 18,000 pounds or for any truck with an unloaded weight over 8,000 pounds and any tractor with an unloaded weight over 4,000 pounds. An automotive fuel carrier (AFC) certificate of registration is required for any truck, trailer, or semi-trailer transporting automotive fuel (NYSDTF 2011b).

New York State has a motor fuel tax on motor fuel and diesel motor fuel sold in the State. The tax is imposed when motor fuel is produced in or imported into New York State and when diesel motor fuel is first sold or used in the State. It is jointly administered and collected with the petroleum business tax. The tax is paid by registered motor fuel and diesel motor fuel distributors (NYSDTF Finance 2011c).

Motor vehicle fees, which are collected by the New York State Department of Motor Vehicles, are another large source of income for the NYSDOT. Other taxes collected for the NYSDOT include the auto rental tax, corporation and utility tax, and other miscellaneous receipts, although the PBT, HUT, motor fuel tax, and motor vehicle fees are the main sources of revenue.

Table 2.113 shows the actual total receipts for years 2009-2010 and 2010-2011 for the NYSDOT, as well as the estimated receipts for year 2011-2012. Total receipts allotted to the NYSDOT increased from 2009 to 2011 and are expected to continue to increase through 2012.

Table 2.113 - NYSDOT Total Receipts, 2009-2012 ($ thousands) (New August 2011)

	2009-2010 Actual	2010-2011 Actual	2011-2012 Estimated
Petroleum Business Tax	612,502	605,945	614,000
Highway Use Tax	137,247	129,162	144,000
Motor Fuel Tax	401,099	407,725	404,000
Motor Vehicle Fees	626,589	813,264	827,000
Auto Rental Tax	51,726	60,032	65,000
Corporation and Utility Tax	19,641	16,400	15,000
Other Miscellaneous Receipts	635,045	467,876	578,902
Total Tax Receipts	**1,848,804**	**2,032,528**	**2,069,000**
Total Receipts	**2,483,849**	**2,500,404**	**2,647,902**

Source: Zerrillo 2011.

The actual amount of total receipts in the year 2010-2011 was $2.5 billion. Approximately $1.4 billion, or 45.7%, came from business taxes, including the motor fuel, petroleum, and highway use taxes. Approximately $813 million, or 32.5%, came from motor vehicle fees, and $544 million, or 21.8% came from auto rental and corporation and utility uses taxes and other miscellaneous receipts. In the estimated receipts for next year (2011-2012), all income related to taxes is estimated to remain relatively constant, whereas there is expected to be a $200 million increase in motor vehicle fees due to increases in fees (Table 2.113).

Collectively, revenues from these taxes flow into the state's Dedicated Highway and Bridge Trust Fund (DHBTF), which is the primary funding source for the NYSDOT highway and bridge capital program, engineering and program administration, DMV administration, as well as capital programs for transit, rail and aviation. In addition to these tax revenues, state general fund support is required to sustain the DHBTF and provide for new project commitments.

NYSDOT is implementing the final year of a two-year capital program for which approximately $1.8 billion is annually dedicated to capital rehabilitation and replacement of the state and local road and bridge system. Despite past investment, the condition of the state's highway pavements and bridges is declining. Given the age of the state's highway system, the capital program, by necessity, invests largely in safety and asset preservation projects to meet the urgent needs of the transportation system.

In addition to state investment in roads and bridges, local governments invest in local roads and bridge infrastructure maintenance and improvement, largely through local property and other local taxes.

2.3.14.5 Rail and Air Services

New York State is served by an extensive system of rail lines for passengers and freight. Amtrak, operating primarily over rail lines owned by freight railroads, is the solitary provider of intercity rail passenger service in New York State. Over approximately 782 route miles, Amtrak links downstate with upstate cities that include Albany, Utica, Syracuse, Rochester, Buffalo, and many other intermediate points. CSX Transportation, Canadian Pacific Railway, and Norfolk Southern Railway are the primary owners and operators of freight corridors in New York State. CSX Transportation is the largest among these railroads, operating 1,292 of the total 4,208 miles of freight rail in the state. Fifty-nine of New York State's 62 counties are served by one of New York's freight railroads, which connect to all adjacent states and Canadian provinces (NYSDOT 2009). The principal rail lines in New York State are shown on Figure 2.18.

Freight carried by railroad is off-loaded at rail yards and transported to specific locations from the railroads by truck. The rail network in New York State is capable of carrying much of the drill equipment that might be required, although it would still have to be moved by truck from the rail yards to the well heads.

Many of the communities in and near the gas development areas are serviced by commercial airliners, including those associated with airports in smaller cities such as Jamestown, Binghamton, and Elmira, and in larger cities such as Buffalo, Rochester, and Syracuse. Figure 2.18 shows the location of Commercial - Primary airports, which are publicly-owned airports that receive scheduled passenger service and have more than 10,000 enplaned passengers per year. A list of Commercial - Primary airports in New York State is provided below. Some airports that are not categorized as Primary airports, because they fall below the 10,000 passenger per year passenger count, also are serviced by scheduled air carriers. The Jamestown airport is one such facility that lies within the area of potential shale gas development.

- Albany International Airport;
- Greater Binghamton Airport;
- Buffalo Niagara International Airport;
- Elmira/Corning Regional Airport;
- Long Island MacArthur Airport;
- Ithaca Tompkins Regional Airport;
- John F. Kennedy International Airport;
- LaGuardia Airport;
- Stewart International Airport;
- Plattsburgh International Airport;
- Greater Rochester International Airport;
- Syracuse Hancock International Airport; and
- Westchester County Airport.

In addition to Commercial - Primary airports, there are many other public use airports that can be utilized by charter operations. None of these airports are at or near capacity and can be available to service an influx of temporary workers.

2.3.15 Community Character[49]

A community's character is defined by a combination of natural physical features, history, demographics and socioeconomics, and culture (Robinson 2005). Key attributes or features used to define community character generally include local natural features and land uses; local history and oral traditions; social practices and festivals; unique local restaurants and cuisine; and local arts. In addition, New York State's Environmental Quality Review Act acknowledges community character as a component of the environment, including existing patterns of

[49] Subsection 2.4.15, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

population concentration, distribution or growth, and existing community or neighborhood character.

Local and regional planning are important in defining a community's character and long-term goals. In New York State, planning, zoning, and local law are implemented and enforced at the local level, through county and municipal boards or councils. The local entities set forth the community's goals and objectives through planning or zoning documents, which provide the most tangible and formal expression of a community's character. Notably, a 2007 New York State Court of Appeals decision (Village of Chestnut Ridge vs. Town of Ramapo) observed that "[t]he power to define the community character is a unique prerogative of a municipality acting in its governmental capacity" and, that, generally, through the exercise of their zoning and planning powers, municipalities are given the job of defining their own character (NYSDEC 2007).

A sense of place also is central to community character or identity. "Sense of place" can be described as those tangible and intangible characteristics which, over a period of time, have given a place its distinctiveness, identity, and authenticity (Robinson 2005). Distinctiveness can be globally, nationally, or regionally important, as well as locally or personally important. The various elements that comprise sense of place include, but are not limited to, regional and local planning, population density, transportation and access, and services and amenities.

To be a defined "place" a bounded area must be recognized by those within and without it as being a distinctive community and having a distinctive character. A sense of place and community character cannot be described for New York State as a whole due to the vast area it covers and the range of differences in communities across the state. Residents of a single place share their history, resources, and common concerns and have a similar way of life. Regions A, B, and C (Figure 2.3) were developed for the purposes of the SGEIS to generally describe representative areas of impact within the area underlain by the Marcellus Shale in New York State. Because they encompass numerous counties and municipalities with diverse land uses, planning goals, and identities, it is difficult to fully describe community character at the regional level. Each community within these regions has its own set of distinctiveness, authenticity, and identity. For the purposes of this analysis, the sense of place for a county or region was described utilizing regional, county, and local comprehensive plans, economic development plans, and Web sites. These resources were used to piece together the sense of place for the representative regions.

Region A

Region A comprises Broome, Tioga, and Chemung Counties (Figure 2.4a). It is located in the eastern portion of the Southern Tier of New York, along the New York/Pennsylvania border. The Southern Tier Expressway (Interstate 86) crosses the southern portion of Region A, providing east/west access, and connecting the cities of Elmira in Chemung County, Waverly and Oswego in Tioga County, and Binghamton, Endicott and Johnson City in Broome County. Most of the urban development occurs along this corridor. The remainder of the region is rural; the rural landscape is dominated by the hills and valleys along the Susquehanna and Chemung Rivers. Collectively, the counties within Region A comprise 38 towns/cities, 18 villages, and many unincorporated areas. There are 21 combined school districts in the Region.

Generally, Region A can be described as having relatively small urban centers and quaint villages surrounded by small, scattered, and picturesque rural communities, largely set within the hills and valleys along the Susquehanna and Chemung Rivers. The Susquehanna and Chemung River valleys are a large part of the natural landscape and create vistas important to local communities. The natural landscape is home to a variety of wildlife, which is enjoyed by residents and visitors both passively (e.g., hiking and bird watching) and actively (e.g., fishing and hunting). Rural elements include scenic drives/routes, farmland, woodlands, forests, waterways, and natural areas. Villages and towns in Region A are quaint and historic and are also home to many musicians and artisans. In Region A, officials and residents describe their communities as being friendly and having a small-town feel and their residents as hard-working and ethical. Many note their country fairs, unique shops, and overall rural characteristics as contributing to their community's character.

Within the counties that comprise Region A, agriculture is an important part of community character. There are over 1,500 farms within Region A, and approximately 279,000 acres of land within the Region are located within 11 state-designated agricultural districts (NYSDAM 2011). Figure 2.19 provides an overview of the agricultural districts within Region A.

Region A is rich in history and historic preservation opportunities. Chemung County and the city of Elmira are considered to be “Mark Twain Country,” because it is the area where Mark Twain lived a large portion of his life and where he died. The character of Region A is influenced by numerous sites and events associated with Native American history, the Revolutionary War and Civil War, and the Underground Railroad, as well as historic villages, towns, and farms (Chemung County Chamber of Commerce 2011). The town of Owego, in Tioga County, has 151 homes that are located in historic districts (Visit Tioga 2011), and numerous Victorian homes throughout the region contribute to the historical aspect of its region’s character.

The region aims to maintain a “Main Street” and small local business attitude by promoting economic growth and maintaining a rural character.

Agri-tourism in the form of petting zoos, U-pick farms, and farmers markets is a large part of the community character of the region. An abundance of outdoor recreational activities, including hiking, biking, fishing, boating, hunting, cross-country skiing, and bird-watching, contributes to the high quality of life these communities all strive for. These activities are counterbalanced by many opportunities to enjoy art, music, and other cultural amenities provided by the region’s cities and towns.

Drilling for natural gas has been performed to a limited extent in Region A; in 2009 there were only 46 gas wells in the region (NYSDEC 2009). Of these, 45 active gas wells are located in Chemung County and one is in Tioga County. In addition, there are 13 underground gas storage wells in operation in Tioga County (NYSDEC 2011).

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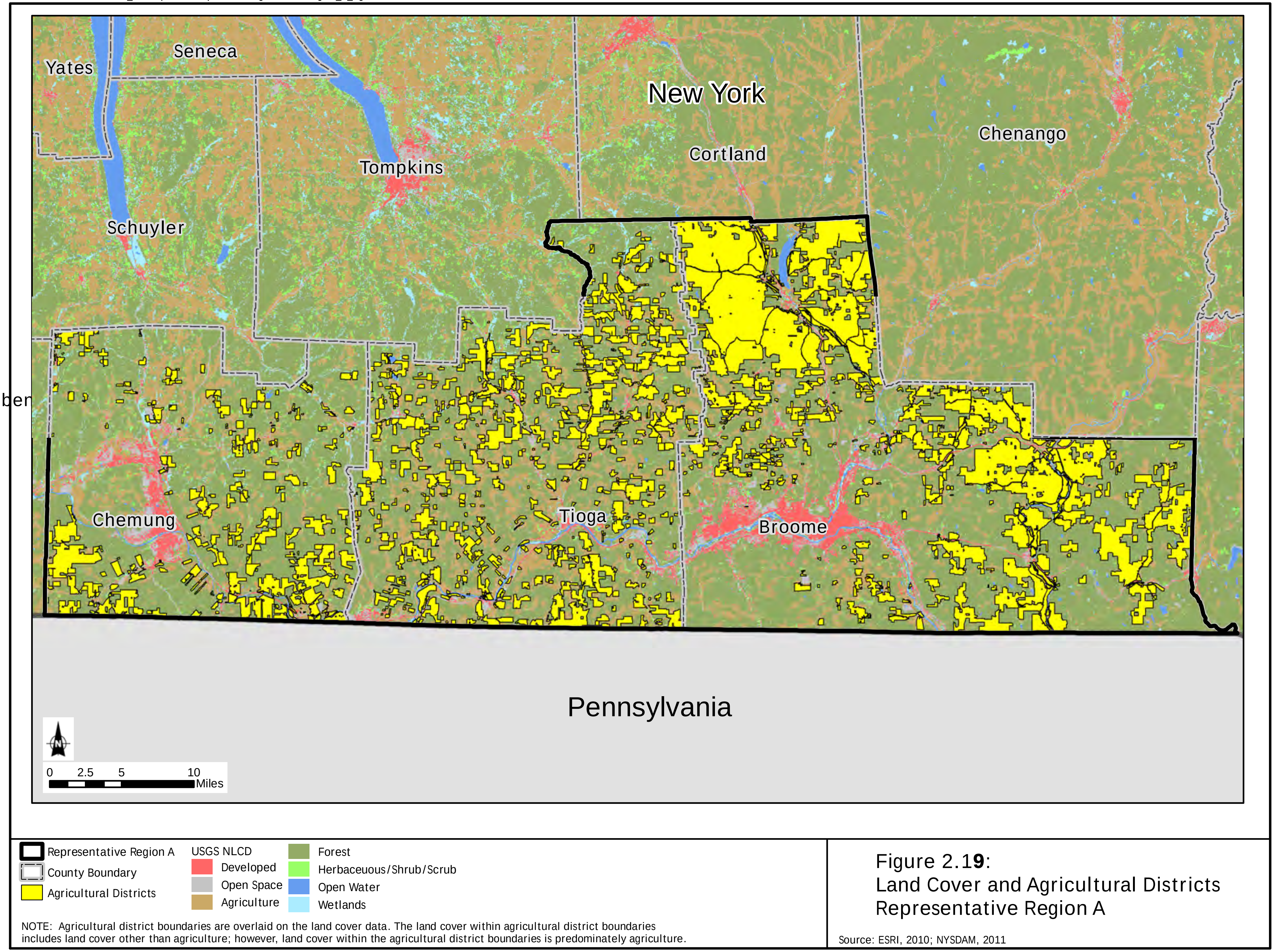


NOTE: Agricultural district boundaries are overlaid on the land cover data. The land cover within agricultural district boundaries includes land cover other than agriculture; however, land cover within the agricultural district boundaries is predominately agriculture.

Figure 2.1**9**:
Land Cover and Agricultural Districts
Representative Region A

Source: ESRI, 2010; NYSDAM, 2011

Broome County. Broome County is the furthest east in the region. The county has a total area of 715 square miles, including 707 square miles of land and 8 square miles of surface water (lakes, ponds, rivers, and streams). Broome County is more densely populated than the other counties in Region A, with a population density of 284 persons per square mile.

Within Broome County are 17 towns/cities and seven villages, and 12 school districts (Broome County 2011; New York Schools 2011a). The Binghamton-Johnson City-Endicott Tri-City Area is the predominant urban area of the county, which is surrounded by suburban development (Greater Binghamton Chamber of Commerce 2011). Major manufacturers located in Binghamton include Lockheed Martin (systems integration), BAE Systems (mission systems) and IBM Corporation (technology). Large healthcare facilities are also located in Binghamton, including United Health Services and Lourdes Hospital. The State University of New York at Binghamton is also a large employer within the region.

The Southern Tier Expressway (Interstate 86/NYS Route 17) crosses the southern portion of Broome County in an east-west direction, and Interstate 81 provides northern access to the cities of Cortland and Syracuse and the New York State Thruway.

The remaining land area in Broome County is largely rural. As reported by the Census of Agriculture, in 2007 there were 580 farms in Broome County, covering approximately 98,000 acres of land (22% of the total land area of the county). The average size of a farm in Broome County in 2007 was 150 acres. Principal sources of farm income include milk, cattle/calves, other crops/hay and nursery, greenhouse, floriculture, and sod. Dairy products account for approximately 70% of agricultural sales in the county (USDA 2007). As of 2011, there were approximately 153,000 acres of land within three state-designated agricultural districts in Broome County (NYSDAM 2011). Agri-tourism in Broome County focuses on farmers markets, U-pick farms, alpaca farms, apples, botanical gardens, and maple syrup (Visit Binghamton 2011).

Broome County and Tioga County are a part of the Susquehanna Heritage Area, which seeks to use the historic, cultural, and natural resources of the counties to strengthen the region’s identity, enhance the local quality of life, support the local economy, and promote stewardship (Susquehanna Heritage Area 2009).

Broome County's Department of Planning and Economic Development "serves to promote the sound and orderly economic and physical growth of Broome County and its constituent municipalities…it implements projects and programs designed to improve the economy, environment and physical infrastructure of the county" (Broome County 2009). Development of comprehensive plans is generally left to the discretion of city and town zoning and planning boards, which originally adopted traditional forms of regulation in an effort to protect land use and natural resources. Local and regional development is guided by a number of open space plans, local comprehensive plans, and strategic plans. These documents broadly reflect a community's history, values, future goals, and character.

Broome County does not have a comprehensive or master plan, but many of its larger municipalities have a comprehensive/master plan, land use regulations/laws, and zoning maps. A brief review of representative local planning documents indicated that several communities in the county are concerned with protecting and maintain agricultural activities in order to preserve open space, promote historic preservation, and preserve and enhance the sense of community identities. As an example, the Town of Union's Unified Comprehensive Plan outlines the following goals and objectives: "protect and maintain agricultural activities as a land use option in order to preserve open space . . . promote a balance between the need to use and the need to preserve resources . . . [and] . . . promote historic preservation" (Town of Union 2009).

Tioga County. Tioga County is located in the Southern Tier of New York State, west of Broome County. This county has a total area of 523 square miles, including 519 square miles of land and 4 square miles of surface waters (lakes, ponds, rivers, and streams). Tioga County has the lowest population density in Region A, with 98.6 persons per square mile.

Within Tioga County are nine towns and six villages, as well as six school districts (Tioga County 2011a; New York Schools 2011b). The largest urban developments are Owego (19,883 persons in the town and 3,896 persons in the village) and Waverly (4,444 persons). The Binghamton-Johnson City-Endicott Tri-City Area also extends from Broome County into the eastern edge of Tioga County. The existing land use pattern in Tioga County has been influenced by the historic pattern of highway-oriented transportation and employment provided by IBM Corporation and later Lockheed Martin (Tioga County 2005). The presence of technologically advanced industries in the southern portion of the county, along the Southern Tier Expressway and near Owego, led to that portion of the county being more densely populated than the northern portion. There are no major roadways running east-west in the northern portion of the county.

The remaining land area in Tioga County is largely rural. As reported by the Census of Agriculture, in 2007 there were 565 farms in this county, covering approximately 106,800 acres of land (32% of the land area of the county). The average size of a farm in Tioga County in 2007 was 189 acres (USDA 2007). The principal source of farm income is dairy products, which accounted for approximately 75% of agricultural products sold in 2007. Other farming in the county includes beef cows, horses, sheep, and poultry. Hay is the largest crop grown in Tioga County, followed by oats and vegetables. Farming operations in Tioga County also produce over 800 gallons of maple syrup (Tioga County 2011a). In recent years, Tioga County has seen decreases in the number of farms, the productivity of farms, and farmed acreage (Tioga County 2005). As of 2011, there were approximately 84,000 acres of land within three state-designated agricultural districts in the county (NYSDAM 2011). Tioga County continues to encourage farm owners to enroll in and work with the NYSDAM to establish agricultural districts to preserve the agricultural character of the county (Tioga County 2005).

Tioga County's physical environment ranges from farming communities to historic town centers with charming "Main Streets" (Visit Tioga County 2011; Tioga County 2005). The county is defined as rural and suburban, but not urban (Tioga County 2011b). The portion of the Susquehanna River basin in Tioga County provides recreational and visual benefits to the county. Tioga County prides itself in its unspoiled beauty, human resources, and central geographic location (Tioga County 2011c).

Tioga County encourages local municipalities to develop their own planning documents (Tioga County 2005). Development of comprehensive plans is generally left to the discretion of village and town zoning and planning boards, which originally adopted traditional forms of regulation in an effort to protect land use and natural resources. Local and regional development is guided by a number of open space plans, local comprehensive plans, and strategic plans. These documents broadly reflect a community's history, values, future goals, and character.

Tioga County does not have a comprehensive or master plan, but many of its municipalities have a comprehensive/master plan, land use regulations/laws, and/or zoning maps. A brief review of representative local planning documents indicated that several communities in the county are concerned with promoting economic development while preserving and maintaining their small town/hometown atmosphere and rural character. The towns also emphasize the importance of conservation and preservation of natural areas and open space, including both agriculture land use and future expansion of recreational community areas. For example, the first goal of the Town of Candor Comprehensive Plan is to “attract and recruit desirable small business and light industry in order to help create a stable tax base and maintain the small town/hometown atmosphere” (Town of Candor 1999).

Chemung County. Chemung County is located west of Tioga County. The county has a total area of 411 square miles, including 408 square miles of land and 3 square miles of surface water. Chemung County has a population density of 218 persons per square mile.

Within Chemung County are 12 towns/cities and five villages, as well as three school districts (Chemung County 2011a; New York Schools 2011c). The existing land use pattern in Chemung County has been significantly influenced by the topography of the region, including the Chemung River Valley. The region’s climate, topography, and soils support productive agricultural, forestry, and wood product industries (Susquehanna – Chemung 2011). The region is rural, with rolling hills, scenic farmlands, rural vistas, and outdoor recreation opportunities, which are all major contributors to the region’s appeal.

The city of Elmira is the largest population center in Chemung County. Located along the Southern Tier Expressway (Interstate 86/17), the city is the historical and cultural center of the county and has numerous historical markers, museums, and tours. The city has the “largest concentration of Victorian-era homes in the State of New York” (Chemung County Chamber of Commerce 2011). Chemung County has many manufacturing industries, which make products such as subway cars, electronic equipment, structural steel products, helicopters, automotive-related products, and paper products (Chemung County 2008).

As reported by the Census of Agriculture, in 2007 there were 373 farms in the county, covering approximately 65,000 acres of land (approximately 25% of the land area of the county). The average size of a farm in Chemung County in 2007 was 175 acres (USDA 2007). Agricultural activities include the production of corn, wheat, hay silage, vegetables, poultry, eggs, beef, milk, milk products, and pork (Chemung County 2008). Approximately 42,000 acres of farmland in Chemung County are located in five agricultural districts (NYSDAM 2011). Farming operations in Chemung County have also decreased over the years, but agriculture is still a major industry in this county.

Chemung County’s topography consists of hills and valleys, with the principal valley being the Chemung River valley (Chemung County 2008). The majority of the county is naturally forested and classified as woodland, but up to 18% of the land area is active agricultural land (Chemung County 2008). Described as the “Gateway to the Finger Lakes,” Chemung County itself has sufficient waterways, rolling hills, scenic farmlands, and outdoor recreational resources to provide a high quality of life for residents and tourists (Susquehanna-Chemung 2011).

Chemung County’s Planning Department assists local communities with comprehensive planning, land use and zoning, floodplains and watersheds, and grant proposals (Chemung County 2011b). Chemung County empowers the local municipalities to develop their own planning documents and periodically presents specialized training workshops for local planning and zoning officials (Chemung County 2011b, 2011c). Development of comprehensive plans is generally left to the discretion of village and town zoning and planning boards, which originally adopted traditional forms of regulation in an effort to protect land use and natural resources. Local and regional development is guided by a number of open-space plans, comprehensive plans, and strategic plans. These documents broadly reflect a community’s history, values, future goals, and character. The Chemung County Planning Department participates actively in the Rural Leadership program of the Southern Tier Regional Planning and Development Board (Chemung County 2011b).

Chemung County does not have a comprehensive or master plan, but many of its municipalities have a comprehensive/master plan, land use regulations/laws, and/or zoning maps. A brief review of representative local planning documents indicated that several communities in the county are concerned with protecting their small town feel, maintaining a similar population size, enhancing recreational amenities, and protecting environmentally significant and/or sensitive areas while minimizing anthropogenic adverse impacts on the land and, consequently, the quality of life of the residents. For example, the Village of Horseheads Comprehensive Plan states their village "... is an inviting place where diverse residents choose to live, work, and play; it is a blend of residential neighborhoods, commercial and manufacturing businesses, parks, and open spaces. Residents and Village officials take pride in the surroundings by assuring the maintenance and beauty of homes, land, and property" (Village of Horseheads 2010).

Region B

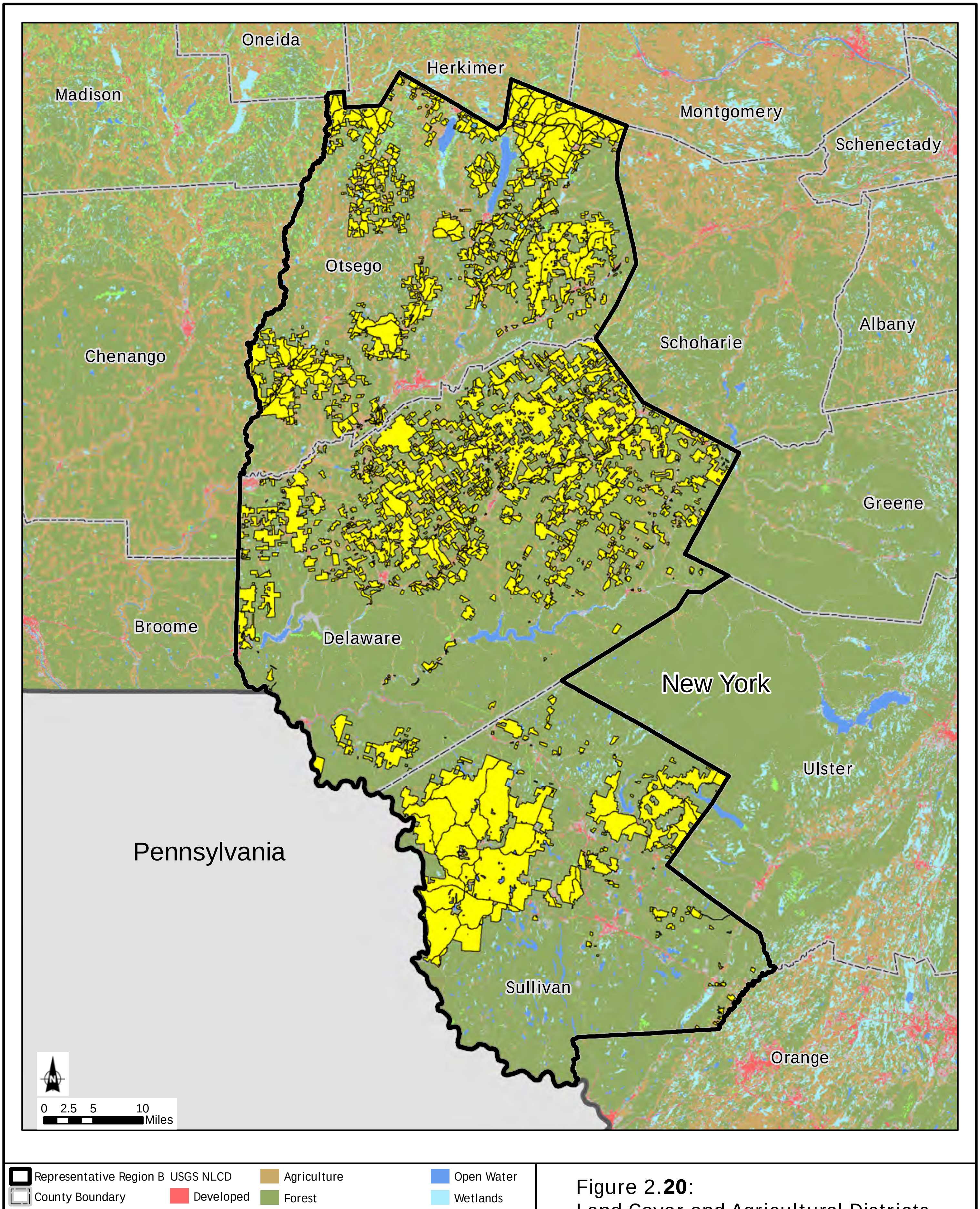
Region B comprises Delaware, Sullivan, and Otsego Counties (Figure 2.4b). Region B is located in the Catskill Mountains and the Leatherstocking region of New York and has a rich natural and human history. The National Baseball Hall of Fame is located in Cooperstown, in Otsego County, and is a destination for thousands of people annually. Glass museums, history museums, and other tourist attractions exist throughout the region. The Catskills are an attraction for outdoor enthusiasts. Various manufacturing companies are located across the region, mainly occurring in the larger towns. The region is known for manufacturing communications equipment, integrated circuits, pharmaceuticals, transportation equipment, plastic and rubber products, and food and beverages. Other large employers include insurance companies, colleges, health care facilities, and retailers. NYSEG, Verizon, and other electronics companies are located in the city of Oneonta (City of Oneonta 2011). Having manufacturing and cultural hubs surrounded by natural areas contributes to the community character of the region.

Within the region there are 60 towns, 26 villages, and over 75 hamlets; 42 combined school districts. Gas drilling is relatively new to these counties and is not an integral part of the industrial or rural landscape of the region. In 2009 there were no natural gas wells in production in Region B (NYSDEC 2009). Several exploratory wells were developed in 2007 and 2009, but no production has been reported.

Generally, Region B can be described as having relatively small urban centers and villages surrounded by numerous small, scattered, and picturesque rural hamlets within a setting of sparsely populated hills, mountains, and valleys. Some communities boast about their clean water, land, and air and panoramic views of natural beauty, while others are particularly proud of their proximity to larger metropolitan areas. Local Web sites and planning documents describe the less densely populated segments of each community as having a rural character, with few buildings, structures, or development (Catskills Region 2011). Rural elements include meandering, tree-lined streets, farmland, woodlands and forests, and natural areas. With the exception of communities immediately along state or county transportation corridors, the hamlets, villages, and towns in Region B generally are pedestrian-friendly or are in the process of revitalizing their neighborhoods to be more walkable (Sullivan County Chamber of Commerce 2011a). Within Region B, views and vistas are dominated by undeveloped open space (Town of Otsego 2005). In Delaware County, this was reinforced by the 1997 Watershed Memorandum of Agreement with NYC.

There are over 1,900 farms within the three counties that comprise Region B; consequently, agriculture is an important part of community character within the Region. Approximately 588,000 acres of land within Region B are located within 15 state-designated agricultural districts (NYSDAM 2011). Figure 2.20 provides an overview of the agricultural districts within Region B.

In Region B, many of the inhabited places are small and the pace of life is slow. Some local officials and residents describe their communities as being friendly and having a small-town feel. Many note their country fairs, specialty shops, and team sports as contributing to their community's character. Delaware and Sullivan Counties are described as rural retreats for urban tourists from NYC. The City of Oneonta, in Otsego County, describes itself as a religious community, known for its many places and worship. All of the counties in Region B describe active and passive recreational activities as being essential to their community character. Available outdoor recreational activities include hiking, fishing, boating, biking, bird-watching, hunting, skiing, and snowmobiling.



NOTE: Agricultural district boundaries are overlaid on the land cover data. The land cover within agricultural district boundaries includes land cover other than agriculture; however, land cover within the agricultural district boundaries is predominately agriculture.

Figure 2.**20**:
Land Cover and Agricultural Districts
Representative Region B

Source: ESRI, 2010; NYSDAM, 2010, 2011

Region B, while rural and slow-paced in some areas, also has several centers of commerce, high-quality health care facilities, institutions of higher education, and noteworthy cultural activities, including art galleries, theatre groups, and music events. These assets significantly contribute to their “sense of place.” For centuries the Catskills Mountains in Delaware County have been a place where art colonies flourished. In Cooperstown, in Otsego County, the Baseball Hall of Fame, Glimmerglass Opera, art galleries, and specialty shops draw throngs of visitors each year. Sullivan County describes itself as offering value and convenience for visitors seeking an escape closer to home, with museums, antiques, boutiques and theater, as well as outdoor recreational activities. It is best known as the home of the Woodstock music festival and the Monticello Raceway. Agri-tourism also is important to Sullivan County.

Delaware County. Geographically, Delaware County is the largest county in Region B and is one of the larger counties in New York State (Delaware County Chamber of Commerce 2011a). Delaware County is located in the southeastern part of the state and is bordered to the south by the Delaware River. The Catskill Mountains are partially located in Delaware County. The county has a total area of 1,468 square miles, including 1,446 square miles of land and 22 square miles of surface water (lakes, ponds, rivers, and streams). Delaware County is one of the least populated counties in New York State, with 33 persons per square mile. The county has 19 cities/towns, 10 villages, two hamlets, and 13 school districts (Delaware County 2011; Delaware County Chamber of Commerce 2011b; New York Schools 2011d). The largest population centers are the villages of Sidney (3,900 persons), Walton (3,088 persons), and Delhi (3,087 persons). Interstate 86/Route 17 crosses the southern boundary of Delaware County.

The remaining areas in Delaware County are rural. As reported by the Census of Agriculture, in 2007, there were 747 farms in the county, covering approximately 200,000 acres (22% of the land area in the county). The average size of a farm in Delaware County in 2007 was 222 acres. The principal sources of farm income include milk, vegetables, other crops/hay and nursery, greenhouse, floriculture, and sod (USDA 2007). According to more recent data from the Delaware County Chamber of Commerce, dairy products account for approximately 80% of agricultural sales in the county, and Delaware County represents 80% of the dairy farms in the NYC watershed area (Delaware County Chamber of Commerce 2011b). As of 2011, there were approximately 237,000 acres of land within eight state-designated agricultural districts in Delaware County (NYSDAM 2011).

The existing land use pattern in Delaware County has been influenced by the historic pattern of hamlet development, highway-oriented transportation, and state land ownership. In addition, a major land-acquisition program is underway in Delaware County and other Catskills/Delaware Watershed communities that help to provide an unfiltered drinking water supply to NYC. The acquisition of this land will preclude future development in designated areas (NYC Watershed 2009).

Delaware County does not have a comprehensive plan, but it empowers its municipalities to develop their own planning documents. Development is generally left to the discretion of village and town zoning and planning boards, which originally adopted traditional forms of regulation in an effort to protect land use and natural resources. Local and regional development is guided by a number of open-space plans, comprehensive plans, and strategic plans. These documents broadly reflect a community's history, values, future goals, and character.

Delaware County does not have a comprehensive or master plan, but many of its municipalities have a comprehensive/master plan, land use regulations/laws, and zoning maps. A brief review of representative local planning documents indicated that several communities in the county are concerned with protecting and preserving agricultural land, including niche farming, forestry, and other sensitive areas; maintaining a rural character and the historical context of the communities; preserving existing development patterns and the appearance of residential development; maintaining the natural environment; and minimizing impacts on scenic transportation routes and vistas. For example, the Town of Stamford states in its Final Draft Comprehensive Plan that the town "will be a place that continues to maintain and celebrate its small town, rural character and natural beauty . . . maintain our open spaces and the pristine nature of the environment . . . [and] . . . our quality of life will be enhanced because of the Towns' strong sense of community through its caring, friendly people and the dedicated organizations and volunteers that serve us well" (Town of Stamford 2011).

Sullivan County. Sullivan County is located south of Delaware County. The county has a total area of 1,038 square miles, including 1,011 square miles of land and 27 square miles of surface water (lakes, ponds, rivers, and streams). The county's physical environment ranges from historic urban centers to farming communities nestled within an open-space network that includes the Upper Delaware Scenic and Recreation River (to the west), Catskill Park (to the north) Basherkill Watershed, and Shawangunk Ridge (Sullivan County Catskills 2011a).

Sullivan County has a population density of 76 persons per square mile. Within the county are 15 cities/towns, six villages, and over 30 hamlets; and eight school districts (Sullivan County Catskills 2011b; Sullivan County Chamber of Commerce 2011b). The largest population centers are the Village of Monticello (6,726 persons), and the Village of Liberty (4,392 persons). Interstate 86/Route 17 crosses through the middle of Sullivan County, providing access to New York City, which is approximately 60 miles southeast of Sullivan County.

The remaining portions of Sullivan County are rural and open space. According to the Census of Agriculture, in 2007 there were 323 farms in Sullivan County, covering approximately 63,600 acres (approximately 10% of the land area of the county). The average size of a farm in 2007 was 156 acres (USDA 2007). In 2007, the principal sources of farm income included poultry and eggs, milk and other dairy products from cows (USDA 2007). Poultry and eggs accounted for approximately 65% of agricultural sales in the county in 2007. In recent years, however, Sullivan County has seen a decrease in traditional dairy and livestock farms (it now has only two major egg producers and 28 dairy farms) and an increase in smaller niche and diversified vegetable and livestock farms. As of 2011, there were approximately 162,000 acres of land within two state-designated agricultural districts in Sullivan County (NYSDAM 2011).

In its Comprehensive Plan, the county describes itself as being on the verge of becoming urban, with rapid growth and development that will change its character and have an impact on its resources (Sullivan County Catskills 2005). The county's vision and community land use goals include avoiding heavy traffic, strip malls, and loss of open space and ensuring the availability of affordable housing. While development decisions are made at the local level, the county encourages collective support of a unified vision in its Comprehensive Plan (Sullivan County Catskills 2005). As stated in the Comprehensive Plan, current development patterns often mandate a separation of land uses; however, revitalization efforts are focused on mixed-used in-fill development (i.e., development within vacant or under-utilized spaces within the built environment), walkable communities, and streetscape improvements (Sullivan County Catskills 2005). The county also is committed to preserving viewsheds, natural resources, and environmentally sensitive areas through zoning. Lastly, the county encourages coordinated zoning among its municipalities and intends to provide resources to municipalities to upgrade local zoning and land use regulations every 10 years.

Otsego County. Otsego County is located in central New York State, north of Delaware County. It is situated in the foothills of the Catskill Mountains, at the headwaters of the Susquehanna River (Otsego County 2011). The County has a total area of 1,015 square miles, including 1,003 square miles of land and 12 square miles of surface water (lakes, ponds, rivers, and streams). The county has a population density of 62 persons per square mile.

Within the county are 25 cities/towns, nine villages, and 47 hamlets; and 21 school districts The city of Oneonta, the county seat, has a population of 13,901 persons, and is surrounded by suburbs, and villages, hamlets, and farm communities that stretch across the remainder of the county. Interstate 88 crosses the southern portion of Otsego County, connecting the City of Oneonta to Binghamton to the south, and the Albany area to the north.

Farming operations in Otsego County have decreased over the years, but agriculture is still a major industry in the county. Active farmland is concentrated in the mid- to northern portions of the county (Otsego County 1999). According to the Census of Agriculture, in 2007 there were 908 farms in Otsego County, covering approximately 206,000 acres (approximately 30% of the land area of the county). The average size of a farm in Otsego County in 2007 was 201 acres (USDA 2007). The principal sources of farm income include milk, cattle/calves, other crops and hay and nursery, greenhouse, floriculture, and sod. Dairy products account for approximately 70% of agricultural sales in the county (USDA 2007). As of 2011, there were approximately 189,000 acres of land within five state-designated agricultural districts in Otsego County (NYSDAM 2011).

Otsego County does not have a comprehensive or master plan, but most of its 34 municipalities have a comprehensive/master plan, land use regulations/laws, and zoning maps. A brief review of representative comprehensive plans indicated that several communities in the county are concerned with protecting sensitive areas, maintaining a low residential density, preserving existing patterns of land use in hamlets and rural areas, maintaining the natural environment, and minimizing visual blight. For example, the Town of Otsego Comprehensive Plan's vision statement states the following: "We foresee the future Town of Otsego as continuing to have a clean environment, beautiful landscape, and rural character. We foresee carefully managed growth and development, maintaining access to our natural areas. We foresee a place of safety for us and our families." (Town of Otsego 2008). According to the Otsego County Department of Planning, affordable housing and real estate is also important to the county (Otsego County 2009).

Region C

Region C comprises Chautauqua and Cattaraugus Counties (Figure 2.4c). Generally, Region C can be described as largely rural in character, with commercial/industrial hubs located along the Southern Tier Expressway and agri-tourism spread across the region. Some communities boast about their access to water bodies and the recreational opportunities they provide, while others are particularly proud of their proximity to lively cities. Local Web sites and planning documents describe the less densely populated portions of each community as having a rural character and charm. Rural elements include scenic drives/routes, farmlands, woodlands and forests, waterways, and natural areas. Hamlets, villages, and towns in the region are quaint and historic and many are home to museums and historical sites. The unique geological history of the region has endowed it with numerous natural attractions, including the deeply incised valleys of Allegany State Park, the deep gorges of Zoar Valley, and numerous lakes and rivers, all of which contribute to the region's character.

Distinct features in each county contribute to the type of agriculture they support, which in turn influences the character of each county. The floodplains of large streams such as Cattaraugus Creek support dairy farms in Cattaraugus County, whereas the climatic influences of nearby Lake Erie support grape production in Chautauqua County.

The city of Salamanca in Cattaraugus County is the only U.S. city east of the Mississippi River that is located within a Native American tribal land (Seneca Nation of Indians). The proximity to Native American tribal lands and the Native American history of the area are important to this community's character. The residents of Region C are proud of their history and work diligently to preserve and promote it. The promotion of this history is evidenced by historical sites and museums found throughout the region, including the Chautauqua Institution in Chautauqua, New York. This renowned institution opened in the late 1800s and serves as a community center and resource "where the human spirit is renewed, minds are stimulated, faith is restored, and art is valued" (Chautauqua County Chamber of Commerce 2011a). This is another example of heritage forming an important part of community character in Region C.

Region C has a vibrant and diverse agricultural industry, which can be found throughout the rolling hills, rural countryside, and woodlands. The agricultural heritage of the region includes Amish communities in both Cattaraugus and Chautauqua Counties. There are over 2,700 farms in Region C. Approximately 632,000 acres of land within Region C are located within 17 state-designated agricultural districts (NYSDAM 2011). Figure 2.21 provides an overview of the agricultural districts within Region C.

Although agriculture is an important aspect of Region C, there is a balance between rural preservation and urban development. There are numerous small villages and communities within Region C, many of which are rich in historic sites and museums. For example, Jamestown in Chautauqua County is home to the Roger Tory Peterson Institute of Natural History, the Fenton History Center, the Lucy-Desi Museum, and the Desilu Playhouse and Theater. Jamestown's unique character and Victorian heritage are echoed throughout the region.

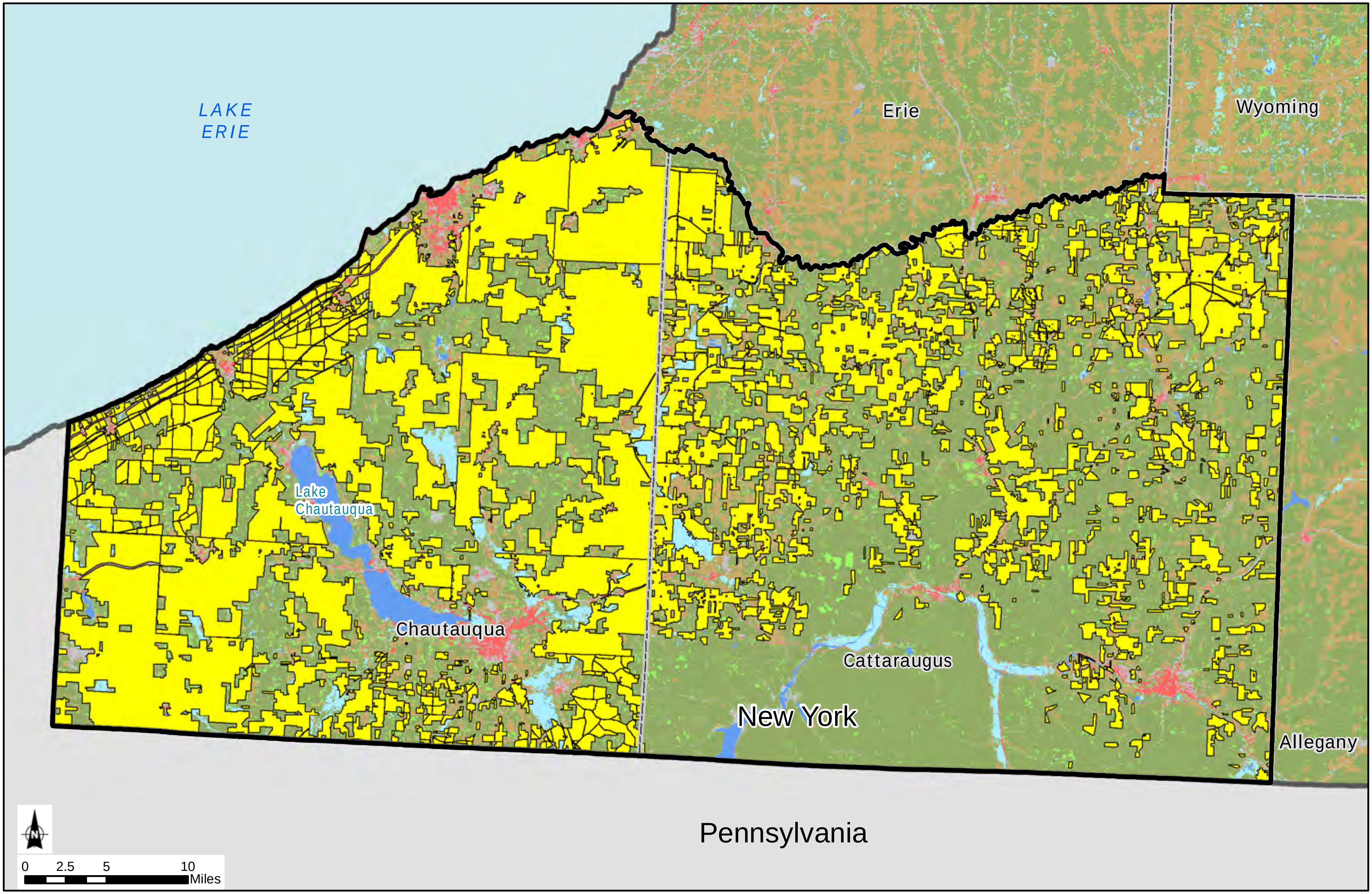
Tourism is also a large part of the community character of the region. Recreational activities that draw tourists to the region include bicycling, boating, fishing, gaming (on Native American tribal land), geo-caching (a treasure-hunting game using GPS technology), golfing, hiking, horseback riding, motor sports, scenic driving, hunting, mountain biking, downhill skiing, cross-country skiing, snowmobiling, snowshoeing, and white water rafting. This abundance of the recreational activities is a significant aspect of the community character in Region C. Within the region are 63 cities/towns, 28 villages, and other unincorporated areas, as well as 30 combined school districts.

Gas drilling is not new to Region C; in 2009 approximately 3,917 gas wells were in production in this region (NYSDEC 2009).

Chautauqua County. Located in the southwestern corner of the state, Chautauqua County is considered the western gateway to New York State (Chautauqua County 2011a). The county is bordered by Lake Erie to the northwest, Pennsylvania to the south and west, the Seneca Nation of Indians and Erie County to the northeast, and Cattaraugus County to the east (Chautauqua County 2011b). The center of the county is Chautauqua Lake; five smaller lakes are located throughout the county. The Southern Tier Expressway crosses the mid-section of the county, and the New York State Thruway crosses the county along its northern border near Lake Erie. Chautauqua County has a total area of 1,500 square miles, including 1,062 square miles of land and 438 square miles of surface water (lakes, ponds, rivers, and streams).

There are two cities within the county, Jamestown to the south and Dunkirk along Lake Erie, which are surrounded by rural areas and lakes. Due to the presence of the two cities, Chautauqua County has an average population density of 127 persons per square mile. Within the county are 29 cities/towns and15 villages, as well as 18 school districts (Chautauqua County 2011a; New York Schools 2011e).

According to the Census of Agriculture, in 2007 there were 1,658 farms in Chautauqua County, which cover approximately 235,858 acres (35% of the land area of the county) (USDA 2007). In 2007 the average size of a farm in this county was 142 acres (USDA 2007). In Chautauqua County, the principal sources of farm income are grape and dairy products (USDA 2007). Grapes and grape products account for approximately 30% of agricultural sales in the county, and dairy products account for approximately 50.5% of agricultural sales (USDA 2007). Grape growers in Chautauqua County produce approximately 65% of New York State’s total annual grape harvest (Tour Chautauqua 2011a). As of 2011, there were approximately 392,000 acres of land within 11 state-designated agricultural districts in Chautauqua County (NYSDAM 2011).



Representative Region C
County Boundary
Agricultural Districts

USGS NLCD
Developed
Open Space
Agriculture
Forest
Herbaceous/Shrub/Scrub
Open Water
Wetlands

NOTE: Agricultural district boundaries are overlaid on the land cover data. The land cover within agricultural district boundaries includes land cover other than agriculture; however, land cover within the agricultural district boundaries is predominately agriculture.

Figure 2.21:
Land Cover and Agricultural Districts
Representative Region C

Source: ESRI, 2010; NYSDAM, 2010, 2011

Agri-tourism in Chautauqua County focuses on wineries in the northern portion of the county and scenic drives and farmers markets in the southern and eastern portions of the county. Another large part of agri-tourism here centers on the county's Amish Country (Tour Chautauqua 2011b).

Other industries also play important roles in the community character of Region C. In Chautauqua County, tourism based on recreational opportunities and historical and cultural sites and events is important throughout the county. Dunkirk, which is strategically located along Lake Erie, is described by the Chautauqua County Chamber of Commerce as having financial and technological support networks that provide businesses with competitive opportunities for growth (Chautauqua County Chamber of Commerce 2011b). The village of Fredonia is home to the State University of New York (SUNY) Fredonia campus, and the educational industry forms a large part of the community's character (Chautauqua County Chamber of Commerce 2011c). Jamestown serves as an industrial, commercial, financial, and recreational hub for southwestern New York, and the city is home to several museums and historical resources (Chautauqua County Chamber of Commerce 2011d). The city of Salamanca is located along the Allegheny River and describes itself as filled with country charm. It is the only city in the U.S. that lies almost completely within the borders of an Indian Reservation (Seneca Nation) (City of Salamanca 2011). The city is located on the northern border of Allegany State Park and serves as a year-round access point to the park. Salamanca is a center for the forestry and wood products industry and has plentiful supplies of maple, oak, and cherry (City of Salamanca 2011).

Chautauqua County has a comprehensive plan called *Chautauqua County 20/20 Comprehensive Plan* (Chautauqua County 2011b), which is designed to assist the county government in making decisions that affect the county's future (Chautauqua County 2011b). The plan identifies strategic issues and goals and is intended to ensure that there is cooperation between municipalities to achieve these goals (Chautauqua County 2011b). The plan states that Chautauqua County has an unusually high number of natural resource assets and unique attractions, including but not limited to farms (dairy and grape), lakes, historic towns, and the Chautauqua Institution (Chautauqua County 2011b). The county considers its traditional agricultural base to have preserved its open space and rural charm, which is a significant aspect of the county's community character (Chautauqua County 2011b).

Cattaraugus County. Cattaraugus County is located directly east of Chautauqua County and is also located within the Southern Tier of New York. The county has a total area of 1,322 square miles, including 1,310 square miles of land and 12 square miles of surface water (lakes, ponds, rivers, and streams). Cattaraugus County has a much lower population density than Chautauqua County, at 61 persons per square mile. Within the county are 34 cities/towns and 13 villages, as well as 12 school districts (Cattaraugus County 2011; New York Schools 2011f).

Cattaraugus County is much more rural than Chautauqua County, with small towns and rural characteristics. There are three Native American reservations wholly or partially within Cattaraugus County. The county's geology was sculpted by glaciers during the last glacial period, and the county is drained by two significant waterways, the Allegheny River in the south and Cattaraugus Creek in the north (Enchanted Mountains 2011a).

The existing land use pattern in Cattaraugus County has been significantly influenced by the topography of the region. Glaciers and rivers have sculpted the county into a mountainous region ideal for a wide variety of outdoor recreational activities, including skiing, hiking, hunting, and camping, and the fertile valleys support productive agricultural communities.

According to the Census of Agriculture, in 2007 there were 1,122 farms in Cattaraugus County, which cover approximately 183,000 acres (USDA 2007). In 2007 the average size of a farm in the county was 163 acres (USDA 2007). The principal sources of farm income are dairy products; nursery, greenhouse, floriculture, and sod; and cattle/calves (USDA 2007). Dairy products account for approximately 68% of agricultural sales in the county (USDA 2007). However, in recent years, dairy farming has declined in Cattaraugus County, especially in areas around towns/cities where the majority of commerce is not based on agriculture, such as around Ellicottville, where tourism is the main source livelihood (Cattaraugus County 2007). As of 2011, there were approximately 240,000 acres of land within six state-designated agricultural districts in Chautauqua County (NYSDAM 2011).

Agri-tourism is an important industry in Cattaraugus County. Agri-tourism in this county centers on maple syrup production and the Amish Trail, which is located in the western portion of Cattaraugus County (Enchanted Mountains 2011b; GOACC 2011).

The city of Olean is the commercial and industrial hub of Cattaraugus County (GOACC 2011). The city has a rich commercial and industrial history and is currently home to several large corporations, including manufacturers such as Dresser-Rand and Cutco-Alcas. This regional industrial and commercial center is necessary to maintain the rural character of the rest of Cattaraugus County**.**

The role of the Cattaraugus County Planning Department is to assist local communities with comprehensive planning, land use and zoning, floodplains and watersheds, census data and demographics, planning for agriculture, and any downtown revitalization projects (Cattaraugus County 2011). Cattaraugus County empowers the local municipalities to develop their own planning documents (Cattaraugus County 2011). Development of comprehensive plans is generally left to the discretion of county and town zoning and planning boards, which originally adopted traditional forms of regulation in an effort to protect land use and natural resources. Local and regional development is guided by a number of open-space plans, comprehensive plans, and strategic plans. These documents broadly reflect a community's history, values, future goals, and character.

Cattaraugus County does not have a comprehensive or master plan, but many of its municipalities have a comprehensive/master plan, land use regulations/laws, and zoning maps. A brief review of representative local planning documents indicated that several communities in the county are concerned with protecting sensitive areas, promoting tourism through recreation activities, maintaining a small town/rural feel, maintaining the natural environment, and creating a balance of the rural character and protection of the environment with appropriate economic development. Affordable housing and real estate also is important to the communities. For example, the Town of Portville Comprehensive Plan outlines the following goals: "… maintain the rural character of the Town, and at the same time provide for anticipated growth and development … [and] … maintain the predominantly rural character by preserving natural woodlands and floodplains, conserving the productive farms as much as possible, encouraging open space areas as a integral part to any new residential development, and concentrating intensive residential and commercial uses into selected centers of activity" (Town of Portville 2003).

In Cattaraugus County, Allegany State Park and the Enchanted Mountains provide recreational opportunities and associated jobs. The village of Ellicottville flourishes on the tourism industry, which centers on two major ski resorts. In the city of Olean, commerce is centered on industry (GOACC 2011).

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Conservation

Chapter 3

Proposed SEQR Review Process

Final

Supplemental Generic Environmental Impact Statement

Chapter 3 - Proposed SEQRA Review Process

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Chapter 3 PROPOSED SEQRA REVIEW PROCESS

3.1 Introduction – Use of a Generic Environmental Impact Statement

The Department's regulations to implement SEQRA[50] authorize the use of a generic environmental impact statement (EIS) to assess the environmental impacts of separate actions having similar types of impacts.[51] Additionally, a generic EIS and its findings "should set forth specific conditions or criteria under which future actions will be undertaken or approved, including requirements for any subsequent SEQRA compliance"[52] such as the need for a supplemental environmental impact statement (SEIS). The course of action following a final generic EIS depends on the level of detail within the generic EIS, as well as the specific follow-up actions being considered. In considering a subsequent action such as permitting horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability reservoirs, the Department must evaluate the generic EIS to determine whether the impacts from the subsequently proposed action (i.e., approval of the permit application) are not addressed, or are inadequately addressed, in the generic EIS, and, in either case, whether the subsequent action is likely to have one or more significant adverse environmental impacts. If significant adverse impacts of the subsequent action are identified, and they are not adequately addressed in the generic EIS, then a site- or project-specific SEIS must be prepared. Under the regulations, generic EISs and their findings should identify the environmental issues or thresholds that would trigger the need for a SEIS. However, if the Department determines that the final generic EIS adequately addresses all potential significant adverse impacts of the subsequently proposed action, then no SEIS is necessary. The SEQRA regulations pertaining to generic EISs (6 NYCRR §617.10[d][1]) provide that when a final generic EIS has been filed, "no further SEQRA compliance is required if a subsequent proposed action will be carried out in

[50] SEQR regulations are available at available at http://www.dec.ny.gov/regs/4490.html.

[51] 6 NYCRR §617.10(a). The regulations define the uses and functions of generic EISs. Frequently asked questions on the use of generic environmental impact statements are posted on the Department's website at http://www.dec.ny.gov/permits/56701.html.

[52] 6 NYCRR §617.10(c).

conformance with the conditions and thresholds established for such actions" in the generic EIS.[53]

3.1.1 1992 GEIS and Findings

Drilling and production of separate oil and gas wells, and other wells regulated under ECL 23 have common types of impacts. Therefore, the Department issued the 1992 GEIS and Findings Statement to cover oil, gas and solution mining activities regulated under ECL 23. The 1992 GEIS is incorporated by reference into this document.[54] Based on the 1992 GEIS, the Department found that issuance of a standard, individual oil or gas well drilling permit anywhere in the state, when no other permits are involved, would not have a significant environmental impact.[55] See Appendix 2.

Also, in the 1992 Findings Statement, the Department found 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 Department permits, may be significant and required a site-specific SEQRA determination. Under the 1992 GEIS, the only instance where issuance of an individual permit to drill an oil or gas well is always deemed significant and therefore always requires an SEIS is when the proposed location is within 1,000 feet of a municipal water supply well.

As part of the 1992 GEIS, the Department also evaluated the action of leasing of state land for oil and gas development and found no significant environmental impacts associated with that action.[56] Specifically, the Department concluded that lease clauses and the permitting process with its attendant environmental review would result in mitigation of any potential impacts that could result from a proposal to drill. See Appendix 3.

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[53] 6 NYCRR §617.10(d)(1).

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

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

[56] Sovas GH, April 19, 2003 (http://www.dec.ny.gov/docs/materials_minerals_pdf/geisfindsup.pdf).

3.1.2 Need for a Supplemental GEIS

As mentioned above, the SEQRA regulations require preparation of a supplement to a final generic EIS if a subsequent proposed action may have one or more significant adverse environmental impacts that were not addressed in the 1992 GEIS.[57] In 2008, 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 SGEIS, or Supplement. This determination was based primarily upon three concerns, as follows: (1) high-volume hydraulic fracturing would require water volumes far in excess of generic EIS descriptions (in the 1992 GEIS), (2) the possibility of drilling taking place in the NYC Watershed, in or near the Catskill Park, and near the federally-designated Upper Delaware Scenic and Recreational River, and (3) the longer duration of disturbance likely to take place at multi-well drilling sites.

1) *Water Volumes*: 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 1992 GEIS does address drilling in watersheds that are major sources of drinking water supply, 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 revised draft 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 1992 GEIS did not address the possibility of drilling in the vicinity of the NYC watershed area which lies in the prospective area for Marcellus Shale drilling; and

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 well pads and thus 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, and a greater intensity of activity at those sites. ECL §23-

[57] 6 NYCRR §617.10(d)(4).

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 were not analyzed in the 1992 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. Under the 1992 Findings Statement, each application to drill a well is deemed by the Department an individual project, meaning each application requires individual review. In terms of SEQRA compliance, the Department considers itself the appropriate lead agency for purposes of SEQRA review involving such applications inasmuch as the Department is the agency principally responsible under ECL §23-0303(2) for regulating oil and gas development activities with local government jurisdiction being limited to local roads and the rights of local governments under the Real Property Tax Law. The Department does not propose to change these aspects of its review.

3.2.1 Scenarios for Future SEQRA Compliance under the SGEIS

- **FIRST SCENARIO:** Applications that conform with the 1992 GEIS and the SGEIS.

Generally, when application documents[58] demonstrate conformance with the thresholds and conditions for such actions to proceed under the 1992 GEIS and the SGEIS, SEQRA would be deemed satisfied, and no further SEQRA process would be required. Upon receipt of an application for a well permit, which will be accompanied by the detailed project-specific information described in Appendix 6, Department staff will determine based on detailed project-specific information whether the application conforms to the conditions and thresholds described in the 1992 GEIS and the SGEIS that entitle the application to be covered by the 1992 GEIS and the SGEIS. If the application conforms to the 1992 GEIS and the SGEIS, Department staff will file a record of consistency statement and no further review under SEQRA will occur in connection with the processing of the well permit application. Permit conditions will be added on a site-specific basis to ensure compliance with the requirements of the 1992 GEIS, the SGEIS, and ECL 23.

[58] See Appendix 4 for a copy of the Application for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas and Solution Mining Regulatory Program.

- **SECOND SCENARIO**: Proposed action is adequately addressed in the 1992 GEIS or the SGEIS but not in respective Findings Statement.

A supplemental findings statement must be prepared if the proposed action and impacts are adequately addressed in the 1992 GEIS and the SGEIS but are not addressed in the previously adopted 1992 GEIS Findings Statement or the SGEIS Findings Statement.

- **THIRD SCENARIO**: Permit applications that are not addressed, or not adequately addressed, in the 1992 GEIS or the SGEIS.

If the proposed action and its impacts are not addressed in the 1992 GEIS or SGEIS, then additional information would be required to determine whether the project may result in one or more additional significant adverse environmental impacts not assessed in the 1992 GEIS or the SGEIS. The projects that categorically fall into this category are listed in Section 3.2.3. Depending on the nature of the action, the additional information would include an environmental assessment form or EAF; topographic, geologic or hydrogeologic 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 project-specific SEQRA determination will either result in 1) a negative declaration (determination of no potentially significant impact), or 2) a positive declaration (requiring the preparation of a site-specific SEIS for the drilling application).

Examples since 1992 where such site-specific determinations have been made include the following actions: i) underground gas storage projects, ii) well sites where special noise mitigation measures are required, iii) well sites that disturb more than two and a half acres in designated Agricultural Districts, and iv) geothermal wells drilled in proximity to NYC water tunnels. As stated above, under the 1992 GEIS wells closer than 2,000 feet to a municipal water supply well would also require further site-specific review. None have been permitted since 1992. The following sections explain how this Supplement will be used, together with the previous 1992 GEIS, to satisfy SEQRA in certain instances when high-volume hydraulic fracturing is proposed.

3.2.2 Review Parameters

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

3.2.2.1 SGEIS Applicability - Definition of High-Volume Hydraulic Fracturing

High-volume hydraulic fracturing is done in multiple stages, typically using 300,000-600,000 gallons of water per stage (Chapter 5). High-volume hydraulic fracturing in a vertical well would be comparable to a single stage. Wells hydraulically fractured with less water are generally associated with smaller well pads and many fewer truck trips, and do not trigger the same potential water sourcing and disposal impacts as high-volume hydraulically fractured wells. Therefore, for purposes of the SGEIS and application of the mitigation requirements described herein, high-volume hydraulic fracturing is defined as hydraulic fracturing that uses 300,000 or more gallons of water, regardless of whether the well is vertical, directional or horizontal. Wells requiring 299,999 or fewer gallons of water to fracture low-permeability reservoirs are not considered high-volume, and will be reviewed and permitted pursuant to the 1992 GEIS and Findings Statement.

Potential impacts directly related to water volume are associated with i) water withdrawals, ii) the volume of materials present on the well pad for fracturing, iii) the handling and disposition of flowback water, and iv) road use by trucks to haul both fresh water and flowback water. The Department proposes the following methodology, applicable to both vertical and horizontal wells that will be subjected to hydraulic fracturing:

≤ 299,999 gallons of water: Not considered high-volume; 1992 GEIS mitigation is sufficient; and

≥ 300,000 gallons of water: Always considered high-volume. The applicant must complete the EAF Addendum. All relevant procedures and mitigation measures set forth in this Supplement are required to satisfy SEQRA without a site-specific determination.

3.2.2.2 Project Scope

As was the case under the 1992 GEIS, 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 case where the project scope extends beyond the well pad and its access road is when the application documents propose surface water withdrawals that have not been previously approved by the Department. Such proposed withdrawals 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.

Gathering lines and pipelines are not within the scope of project review as the PSC has exclusive jurisdiction to review these activities under Public Service Law Article VII. Compressor stations associated with gathering lines and pipelines are also under the PSC's Public Service Law Article VII review authority except that the Department has jurisdiction under ECL Article 19 (Air Pollution Control) to review air emissions and ECL Article 17 for the SPDES program. The foregoing is discussed in greater detail in Chapter 3 of the GEIS and Section 1.5 of the Final Scope. Chapter 5 of this Supplement describes the facilities likely to be associated with a multi-well shale gas production site, and Chapter 8 provides details on the PSC's environmental review process for these facilities.

3.2.2.3 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 an average of 3.5 acres in size, with larger pads possible, during the drilling and hydraulic fracturing stages of operations. Average production pad size, after reclamation, is likely to be 1.5 acres for a multi-well pad. Pads for vertical wells would be smaller. Access road acreage depends on the location, the length of the road and other factors. In general, each 150 feet of access road adds 1/10th of an acre to the total surface acreage disturbance.

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.

3.2.2.4 Lead Agency

For the reasons set out in section 3.2 above, the Department would in most, if not all, instances continue to assert the lead agency role under SEQRA. 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 in the first instance be determined by agreement among the involved agencies. Disputes are decided by the Department's Commissioner pursuant to 6 NYCRR §617.6(b)(5). Where there is an involved agency or agencies other than the Department (meaning another agency with jurisdiction to fund, approve, or undertake the action), to the extent practicable, the Department will seek lead agency designation, which is consistent with the criteria for such designation under SEQRA.

3.2.3 EAF Addendum and Additional Informational Requirements

The 1992 Findings authorized use of a shortened, program-specific environmental assessment form (EAF), which is required with every well drilling permit application.[59] (See Appendices 2 and 5). The EAF and well drilling application form[60] do not stand alone, but are supported by the four-volume 1992 GEIS, the applicant's well location plat, proposed site-specific drilling and well construction plans, Department staff's site visit, and geographic information system (GIS) -

[59] http://www.dec.ny.gov/docs/materials_minerals_pdf/eaf_dril.pdf . Under 6 NYCRR §617.2(m) of the SEQRA regulations, the model full and short EAFs may be modified by an agency to better serve it in implementing SEQR, provided the scope of the modified form is as comprehensive as the model.

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

based location screening, using the most current data available. Oil and gas staff within the Department consults and coordinates with staff in other Department programs administered by the Department 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 to evaluate high-volume hydraulic fracturing projects (≥300,000 gallons) in the context of this SGEIS and its Findings Statement, and 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 constructed for high-volume hydraulic fracturing, regardless of whether the well is vertical or horizontal;

2) With the applications to drill subsequent wells for high-volume hydraulic fracturing on the pad 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.

3.2.3.1 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, 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. Documentation of the operator's evaluation of alternatives to the proposed additive products will also be required.

3.2.3.2 Water Source Information

The operator will be required to identify the source of water 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 and type of source (e.g., stream, lake, pond, groundwater, etc.) and other detailed information will be required to allow the Department to analyze potential impacts and, in the case of stream withdrawals, to ensure the operator's compliance relative to passby flow and the narrative flow standard in 6 NYCRR §703.2.

3.2.3.3 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 from the proposed surface location of the well and the closest edge of the well pad to the relevant resources and features.

- Any known public water supply reservoir, river or stream intake, public or private water well or domestic supply spring within 2,640 feet;
- Any primary or principal aquifer boundary, perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet;
- Any residences, occupied structures or places of assembly within 1,320 feet.
- Capacity of rig fueling tank(s) and distance to:
  - Any public or private water well, domestic-supply spring, reservoir, river or stream intake, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned location(s) of the fueling tank(s); and
- Distance from the surface location of the proposed well to the surface location of any existing well that is listed in the Department's Oil & Gas Database[61] or any other abandoned well identified by property owners or tenants within a) the spacing unit of the proposed well and/or b) within 1 mile (5,280 feet) of the proposed well location, whichever results in the greatest number of wells. For each well identified, the following information would be required, if available:
  - Well name and API Number;
  - Well type;
  - Well status;

[61] The Department's Oil & Gas Database contains information on more than 35,000 oil, gas, storage, solution salt, stratigraphic, and geothermal wells categorized under Article 23 of the ECL as Regulated Wells. The Oil & Gas database can be accessed on the Department's website at http://www.dec.ny.gov/cfmx/extapps/GasOil/.

- Well orientation; and
- Quantity and type of any freshwater, brine, oil or gas encountered during drilling, as recorded on the Department's Well Drilling and Completion Report.

3.2.3.4 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, and completed interval, along with a description of their 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
- The Department's Water Well Information search wizard, available at http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty.

Additionally, geodata on water wells in New York State is available from the Department in KML (Keyhole Markup Language) and shape file formats. To access and download water well information, go to: http://www.dec.ny.gov/geodata/ptk.

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.

3.2.3.5 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 and production brine 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, or centralized tank facility); and
- Identification and permit numbers for any proposed treatment facility or disposal well located in New York.

3.2.3.6 Operational Information

Other required information about well pad operations will include:

1. Information about the planned construction and capacity of the reserve pit;
2. Information about the number and individual and total capacity of receiving tanks on the well pad for flowback water;
3. Indication of the timing of the use of a closed-loop tank system (e.g., surface, intermediate and/or production hole);
4. Information about any off-site cuttings disposal plan;
5. 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;
6. Description of planned public access restrictions, including physical barriers and distance to edge of well pad;
7. Identification of the EPA Tiers of the drilling and hydraulic fracturing engines used, if these use gasoline or diesel fuel. If particulate traps or SCR are not used, a description of

other control measures planned to reduce particulate matter and nitrogen oxide emissions during the drilling and hydraulic fracturing processes;

8. If condensate tanks are to be used, their capacity and the vapor recovery system to be used;

9. If a wellhead compressor is used, its size in horsepower and description the control equipment used for nitrogen oxides (NO_x); and

10. If a glycol dehydrator is to be used at the well pad, its stack height and the capacity of glycol to be used on an annual basis.

3.2.3.7 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.

3.2.3.8 Required Affirmations

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

- passby flow for surface water withdrawals;
- review of local floodplain maps;
- 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;

- adherence to all well permit conditions; and
- adherence to best management practices for reducing direct impacts to terrestrial habitats and wildlife.

3.2.3.9 Local Planning Documents

The EAF Addendum will require the applicant to identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws, regulations, plans or policies. The applicant will also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s).

3.2.3.10 Habitat Fragmentation

Applicants proposing well pads in Forest or Grassland Focus Areas that involve a disturbance in a contiguous forest patch of 150 acres or more in size or a contiguous grassland patch of 30 acres or more in size should not submit the EAF or a well permit application prior to conducting a site-specific ecological assessment in accordance with a detailed study plan that has been approved by the Department. The need and plan for an ecological assessment should be determined in consultation with the Department and will consider information such as existing site conditions, existing vegetative cover and ongoing and historical land management activities. The completed ecological assessment must be attached to the EAF and must include, at a minimum:

- A compilation of historical information about use of the area by forest interior birds or grassland birds;
- Results of pre-disturbance biological studies, including a minimum of one year of field surveys at the site to determine the current extent, if any, of use of the site by forest interior birds or grassland birds;
- An evaluation of potential impacts on forest interior or grassland birds from the project;
- Additional mitigation measures proposed by applicant; and
- Protocols for monitoring of forest interior or grassland birds during the construction phase of the project and for a minimum of two years following well completion.

3.2.4 Prohibited Locations

The Department will not issue well permits for high-volume hydraulic fracturing at the following locations:

1) Any proposed well pad within the NYC and Syracuse watersheds;

2) Any proposed well pad within a 4,000-foot buffer around the NYC and Syracuse watersheds;

3) Any proposed well pad within a primary aquifer (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing);

4) Any proposed well pad within a 500-foot buffer around primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing);

5) Any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing);

6) Any proposed well pad within 500 feet of private drinking water wells or domestic use springs, unless waived by the owner; and

7) Any proposed well pad within a 100-year floodplain.

3.2.5 Projects Requiring Site-Specific SEQRA Determinations of Significance

The Department proposes that site-specific environmental assessments and SEQRA determinations of significance 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, directional or horizontal.

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

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

3) Any proposed well pad within 500 feet of a principal aquifer;

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

5) 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;

6) Any proposed water withdrawal from a pond or lake;

7) Any proposed ground water withdrawal within 500 feet of a private well;

8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland;

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure; and

10) Any proposed centralized flowback water surface impoundment.

The Department will re-evaluate the need for site-specific SEQRA determinations within 500 feet of principal aquifers two years after issuance of the first permit for high-volume hydraulic fracturing.

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. According to the information received to date, the drilling of all high-volume hydraulically fractured wells will create surface disturbances in excess of 2.5 acres. The Department will consult with the Department of Agriculture and Markets to develop permit conditions, best management practices (BMP) requirements and reclamation guidelines to be followed when the proposed disturbance is larger than 2.5 acres on a farm in an Agricultural District. Staff will perform the SEQRA review and publish the results in the Environmental Notice Bulletin (ENB). A large number of agricultural districts are currently located in areas where high-volume hydraulic fracturing drilling is expected to occur but many of these districts have reverted to forestlands and are no longer in agricultural production. Mineral Resources will provide guidance to gas well operators to achieve the goal of reducing or minimizing the surface disturbance to agricultural farmlands. Examples of the proposed Agricultural District requirements include but are not limited to:

- decompaction and deep ripping of disturbed areas prior to topsoil replacement;
- removal of construction debris from the site;
- no mixing of cuttings with topsoil;
- removal of spent drilling muds from active agricultural fields;
- location of well pads/access roads along field edges and in nonagricultural areas (where possible);
- removal of excess subsoil and rock from the site; and
- fencing of the site when drilling is located in active pasture areas to prevent livestock access.

Proposed projects that require other Department permits will continue to require site-specific SEQRA determinations regarding the activities covered by those permits, with one exception. Required coverage under a general stormwater permit does not result in the need for a site-specific SEQRA determination, as the Department issues its general permits pursuant to a separate process.

3.3 Regulations

The Department's oil and gas well regulations, located at 6 NYCRR Parts 550 - 559, contain permitting, recordkeeping, and operating requirements for oil and gas wells. More detailed requirements applicable to drilling operations are routinely attached as conditions to well drilling permits issued pursuant to the ECL. Additionally, the Department's regulations concerning water withdrawals, stormwater control, and the use of state lands, among others, would apply to various aspects of high-volume hydraulic fracturing operations considered in this revised draft SGEIS. Appendix 10 of this revised draft SGEIS contains proposed supplementary permit conditions for high-volume hydraulic fracturing that will be attached to well drilling permits. Although conditions incorporated into well drilling are enforceable pursuant to ECL Article 71, a number of the application requirements specific to high-volume hydraulic fracturing as well as many of the mitigation measures discussed in this revised draft SGEIS will be set forth in regulations. Accordingly, draft revisions and additions to the Department's regulations will be considered as part of the SGEIS process, pursuant to the State Administrative Procedures Act (SAPA) for agency rulemaking.

The enactment of revisions or additions to the Department's regulations relating to high-volume hydraulic fracturing would have a positive effect on the environment by mitigating or otherwise addressing potential environmental impacts from this activity. However, because these regulations would be enacted as part of an action that would authorize high-volume hydraulic fracturing the enactment of such regulatory revisions or additions will be considered in conjunction with the Department's consideration of the significant environmental impacts under SEQRA.

SAPA contains other potential impact areas for state agencies to consider, such as the impact of proposed rules on jobs, rural areas and the regulated community. Some of these types of impacts are discussed in this revised draft SGEIS, but a complete examination of those types of impacts will be evaluated within the rulemaking process. The Department will consider all information generated by the SGEIS and SAPA processes to make determinations on how high-volume hydraulic fracturing operations would be regulated.

NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Chapter 4

Geology

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FIGURES

TABLES

Chapter 4 - GEOLOGY

This Chapter supplements and expands upon Chapter 5 of the 1992 GEIS. Sections 4.1 through 4.5 and the accompanying figures and tables were provided in essentially the form presented here by Alpha Environmental, Inc., under contract to NYSERDA to assist the Department with research related to this SGEIS.[62] Alpha's citations are retained for informational purposes, and are listed in the "consultants' references" section of the Bibliography. Section 4.6 discusses how NORM in the 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 Section 5.8 (Hydraulic Fracturing Design), and Appendix 11 (Analysis of Subsurface Fracturing 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 terms "conventional" and "unconventional" are related more to prevailing technology and economics surrounding the development of a given play than to the reservoir rock type from which the oil or natural gas resources are derived. Gas shales (also called "gas-containing shales") are one of a number of reservoir types that are explored for unconventional natural gas, and this group includes such terms as: deep gas; tight gas; coal-bed methane; geopressurized zones; and Arctic and sub-sea hydrates.

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

[62] Alpha, 2009.

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 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.[63]

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, such as the Marcellus Shale, 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 are 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

[63] Alpha, 2009, p. 121.

where there is evidence that a significant amount of gas has formed and been preserved from the TOC during thermal maturation.[64]

Oil and gas are stored in isolated pore spaces or fractures and adsorbed on the mineral grains.[65] 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.[66] Porosity values of 1 to 3 percent are reported for Devonian shales in the Appalachian Basin.[67] 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).[68] 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.[69] The presence of naturally occurring radioactive materials (NORM) induces 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 (i.e., fragments of rock) 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.[70]

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[64] Alpha, 2009, p. 122.

[65] Alpha, 2009, p. 122.

[66] Alpha, 2009, p.122.

[67] Alpha, 2009, p.122.

[68] Alpha, 2009, p.122.

[69] Alpha, 2009, p. 122.

[70] Alpha, 2009, p. 123.

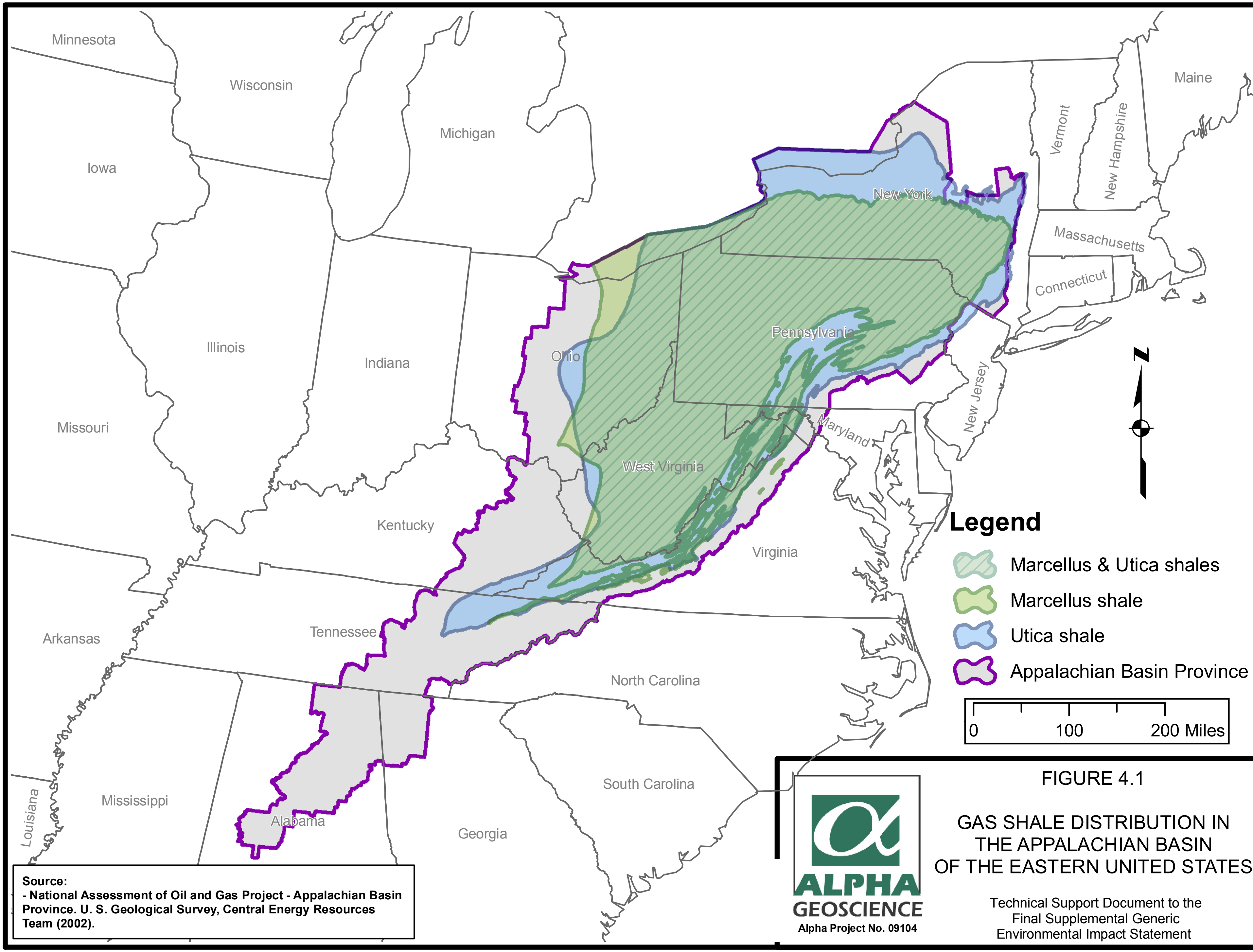

FIGURE 4.1

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

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The stratigraphic column for southwestern New York State is shown in Figure 4.2 and includes oil and gas producing horizons. This figure was initially developed by Van Tyne and Copley,[71] from the analysis of drilling data in southwestern New York State, and it has been modified several times since then as various authors have cited it in different studies. The version presented as Figure 4.2 can also be found on the Department's website at http://www.dec.ny.gov/energy/33893.html. Figure 4.3 is a generalized cross-section from west to east across the southern tier of New York State and shows the variation in thickness and depth of the different stratigraphic units. This figure was initially developed by the Reservoir Characterization Group of the New York State Museum. It is important to note that the geographic areas represented in Figure 4.2 and Figure 4.3 are not precisely the same, and the figures were originally developed by different authors. For example, the Marcellus Shale is shown in Figure 4.2 as the basal unit of the Hamilton Group, but it appears as a discrete unit below the Hamilton Group in Figure 4.3 to highlight its gas-bearing potential. Similarly, the "Devonian Sandstone and Shale" of Figure 4.3 correlates to the Conewango, Conneaut, Canadaway, West Falls, Sonyea, and Genesee Groups of Upper Devonian age shown in Figure 4.2.

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 other black shale formations (Figure 4.2 and Figure 4.3) in New York that may produce natural gas on a localized basis.[72] 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.

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[71] Van Tyne and Copley, 1983.

[72] Alpha, 2009, p. 123.

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).[73] 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.[74]

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 indicates 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.[75]

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 an argillaceous calcareous mudstone to the east. These two members are time-equivalent and grade laterally toward the west into Trenton limestones.[76] 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.[77] This depth corresponds approximately with the base of the organic-rich section of the Utica Shale.

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[73] Alpha, 2009, p. 124.

[74] Alpha, 2009, p. 124.

[75] Alpha, 2009, p. 124.

[76] Alpha, 2009, p. 124.

[77] Alpha, 2009, p. 124.

Figure 4.2 - Stratigraphic Section of Southwestern New York State

Period		Group	Unit		Lithology
Penn.		Pottsville	Olean		Quartz pebble conglomerate & sandstone, quartz pebble, conglomerate, sandstone & minor shale
Miss.		Pocono	Knapp		
Dev.	Upper	Conewango			Shale & sandstone, scattered conglomerates
		Conneaut	Chadakoin		Shale & siltstone, scattered conglomerates
		Canadaway	Undifferentiated[1]	O G O G	Shale & siltstone Minor sandstone
			Perrysburg[2]	O G O G	Shale & siltstone Minor sandstone
		West Falls	Java Nunda Rhinestreet	 G	Shale & siltstone Argillaceous limestone
		Sonyea	Middlesex	G	Shale & siltstone
		Genesee			Shale with minor siltstone & limestone
	Middle		Tully	G	Limestone with minor siltstone & sandstone
		Hamilton	Moscow Ludlowville Skaneateles Marcellus	 G	Shale with minor sandstone & conglomerate
			Onondaga	O G	Limestone
	Lower	Tristates	Oriskany	G	Sandstone
		Helderberg	Manlius Rondout		Limestone & dolostone
Sil.	Upper		Akron	O G	Dolostone
		Salina	Camillus Syracuse Vernon	S S	Shale, siltstone, anhydrite & halite
		Lockport	Lockport	G	Limestone & dolostone
		Clinton	Rochester Irondequoit		Shale & sandstone
	Lower		Sodus Reynales Thorold		Limestone & dolostone
		Medina	Grimsby Whirlpool	G G	Sandstone & shale Quartz sandstone
Ord.	Upper		Queenston Oswego Lorraine Utica	G G	Shale & siltstone with minor sandstone
	Middle	Trenton - Black River	Trenton Black River	G	Limestone and minor dolostone
	Lower	Beekmantown	Tribes Hill Chuctanunda		Limestone & dolostone
Camb.	Upper		Little Falls Galway (Theresa) Potsdam	G G	Quartz sandstone & dolostone; sandstone & sandy dolomite; conglomerate base
PreCamb.			Gneiss, Marble, Quartzite, etc...		Metamorphic & igneous rocks

1 - Includes: Glade, Bradford 1st, Chipmunk, Bradford 2nd, Harrisburg Run, Scio, Penny and Richburg.

2 - Includes: Bradford 3rd, Humphrey, Clarksville, Waugh & Porter, and Fulmer Valley.

O: Oil producing

G: Gas producing

S: Salt producing

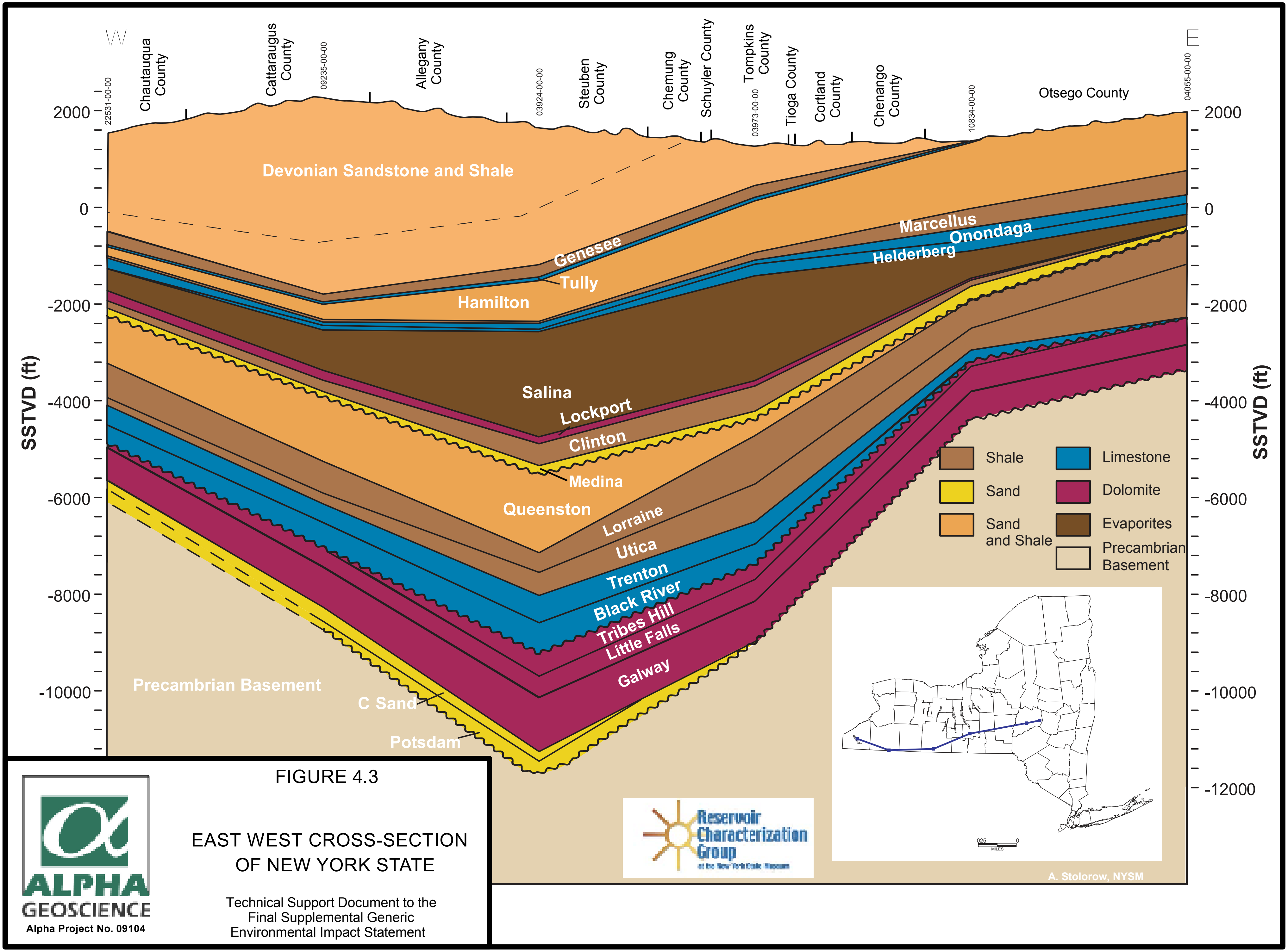

FIGURE 4.3

EAST WEST CROSS-SECTION OF NEW YORK STATE

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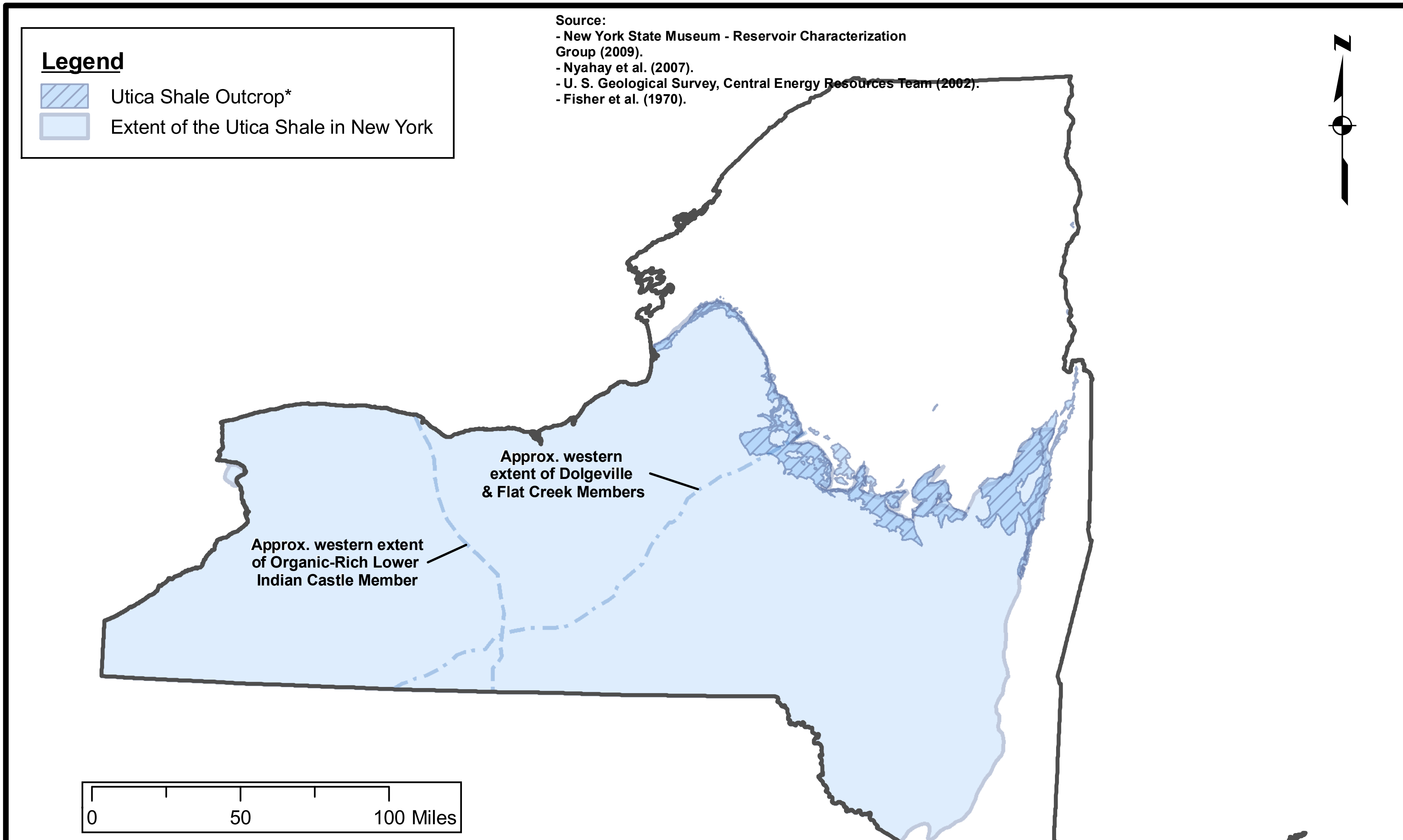

FIGURE 4.4

EXTENT OF UTICA SHALE
IN NEW YORK STATE

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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.[78] 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 values as high as 3.0% in eastern New York and 15% in Ontario and Quebec were also reported.[79]

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.[80] 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.

[78] Alpha, 2009, p. 124.

[79] Alpha, 2009, p. 125.

[80] Alpha, 2009, p. 125.

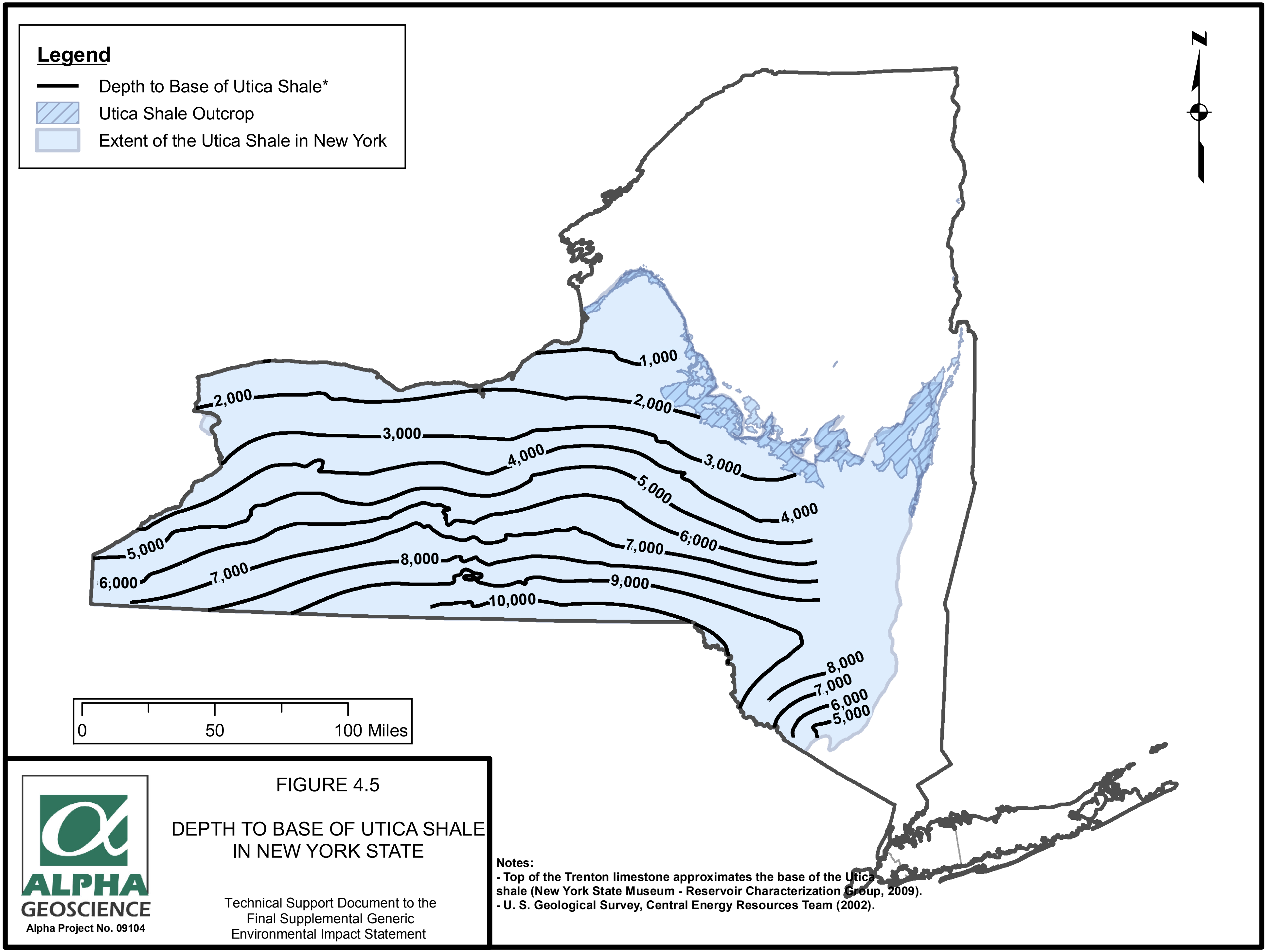
Legend
Depth to Base of Utica Shale*
Utica Shale Outcrop
Extent of the Utica Shale in New York
N
0
50
100 Miles
1,000
2,000
2,000
3,000
3,000
4,000
4,000
5,000
5,000
6,000
6,000
7,000
7,000
8,000
9,000
10,000
8,000
7,000
6,000
5,000
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FIGURE 4.5
DEPTH TO BASE OF UTICA SHALE IN NEW YORK STATE
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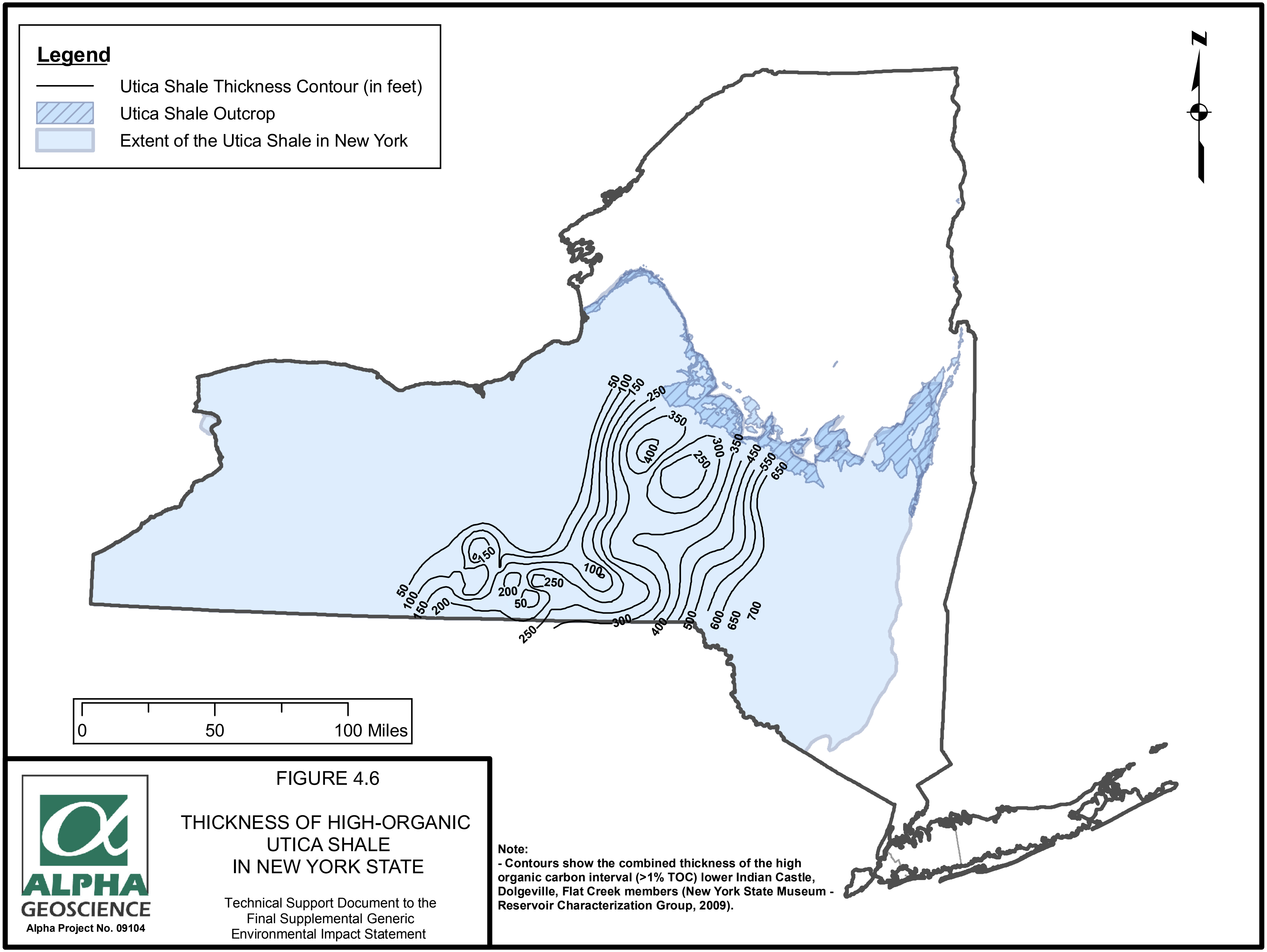
Notes:
- Top of the Trenton limestone approximates the base of the Utica shale (New York State Museum - Reservoir Characterization Group, 2009).
- U. S. Geological Survey, Central Energy Resources Team (2002).


Legend
Utica Shale Thickness Contour (in feet)
Utica Shale Outcrop
Extent of the Utica Shale in New York
N
0
50
100 Miles
ALPHA
GEOSCIENCE
Alpha Project No. 09104
FIGURE 4.6
THICKNESS OF HIGH-ORGANIC
UTICA SHALE
IN NEW YORK STATE
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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.[81] 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.[82] Significant gas shows have been reported while drilling through the Utica Shale in eastern and central New York.[83]

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[81] Alpha, 2009, p. 125.

[82] Alpha, 2009, p. 126.

[83] Alpha, 2009, p. 126.

No Utica Shale gas production was reported to the Department 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.

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[84] and ranges in thickness from less than 25 feet in Cattaraugus County to over 1,800 feet along the Catskill front.[85] 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 underlies an area of approximately 18,700 square miles in New York (Figure 4.8). 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.[86] 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 Shales 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

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[84] Alpha, 2009, p. 126.

[85] Alpha, 2009, p. 126.

[86] Alpha, 2009, p. 127.

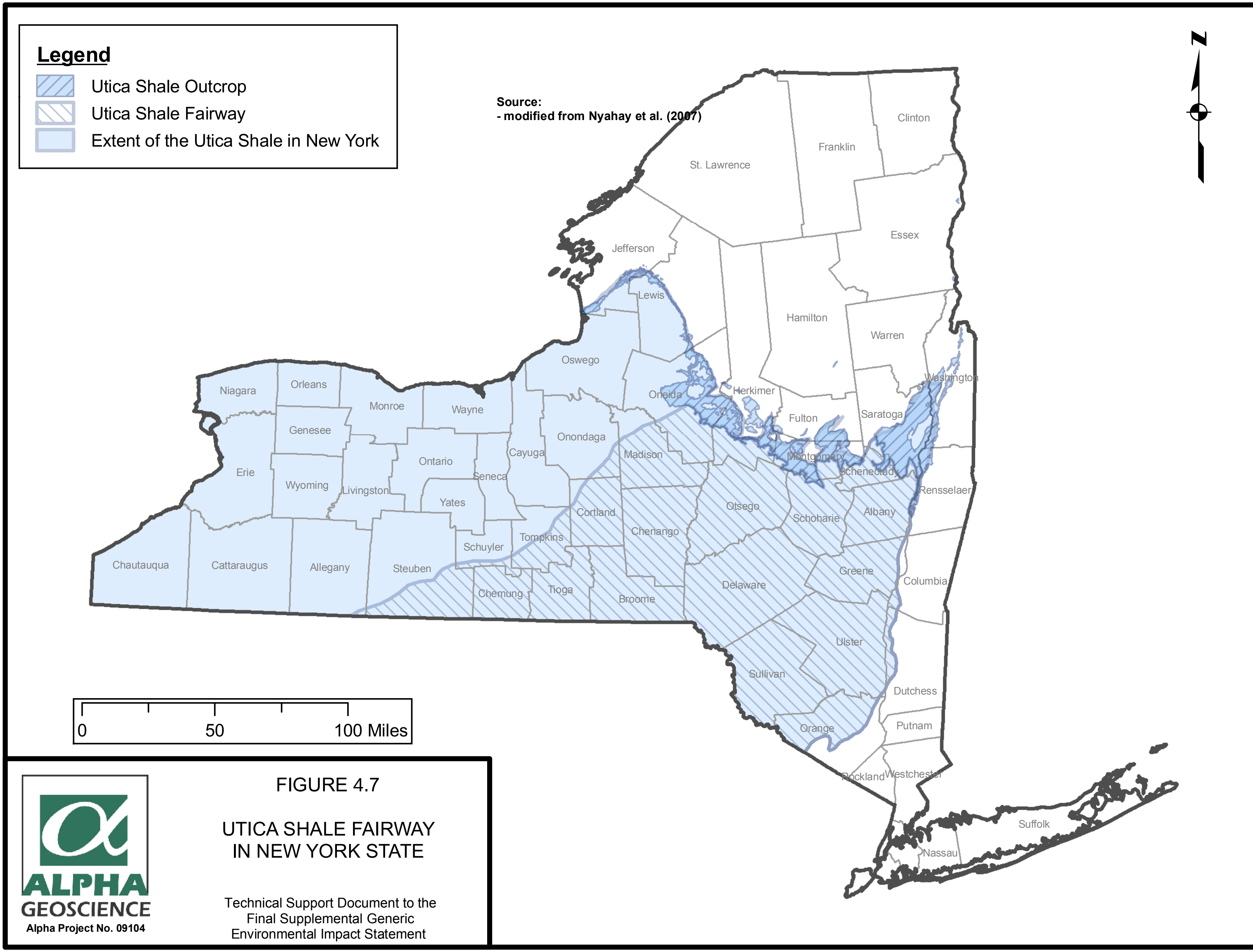

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FIGURE 4.7

UTICA SHALE FAIRWAY
IN NEW YORK STATE

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lower-most portions of the Oatka Creek Shale.[87] 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.[88]

4.4.1 Total Organic Carbon

Figure 4.10 shows the aerial distribution of TOC in the Marcellus Shale based on the analysis of drill cuttings sample data.[89] 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 reported between 3 to 12%[90] and 1 to 10.1%.[91]

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.

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

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[87] Alpha, 2009, p. 127.

[88] Alpha, 2009, p. 127.

[89] Alpha, 2009, p. 127.

[90] Alpha, 2009, p. 127.

[91] Alpha, 2009, p. 127.

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.[92] All gas wells completed in New York's Marcellus Shale as of the publication date of this document are vertical wells.[93]

The Department'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.[94] In 2010, the most recent reporting year available, a total of 34 MMcf of gas was produced from 15 Marcellus Shale wells in Livingston, Steuben, Schuyler, Chemung, Chautauqua, Wyoming 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 Tcf in all Devonian shales within the basin, including the Marcellus Shale. Approximately 164.1 Tcf, or 19%, of that estimated total, was attributed to the 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.

[92] Alpha, 2009, p. 129.

[93] Alpha, 2009, p. 129.

[94] Alpha, 2009, p. 129.

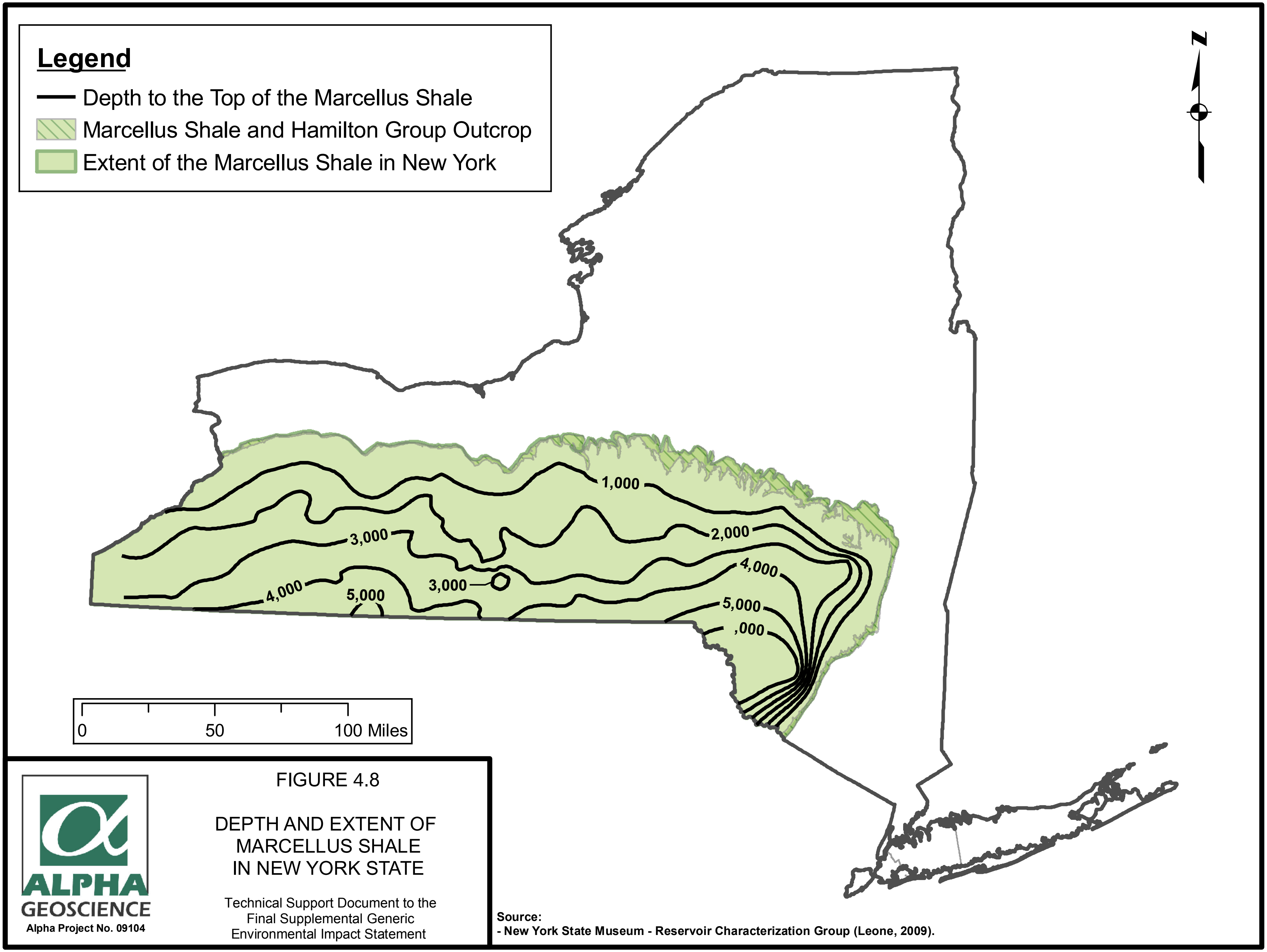

FIGURE 4.8

DEPTH AND EXTENT OF MARCELLUS SHALE IN NEW YORK STATE

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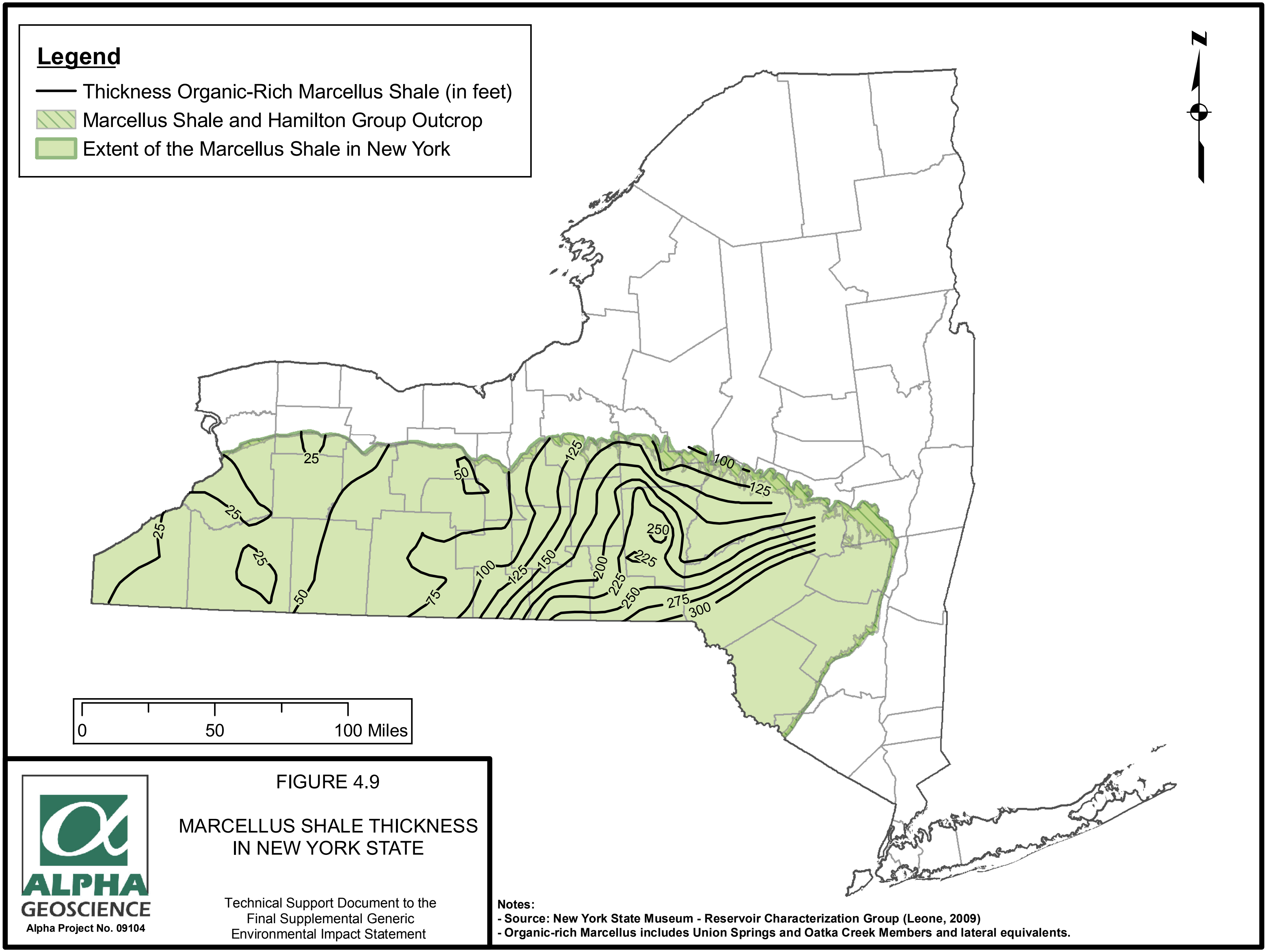

FIGURE 4.9

MARCELLUS SHALE THICKNESS IN NEW YORK STATE

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Notes:

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

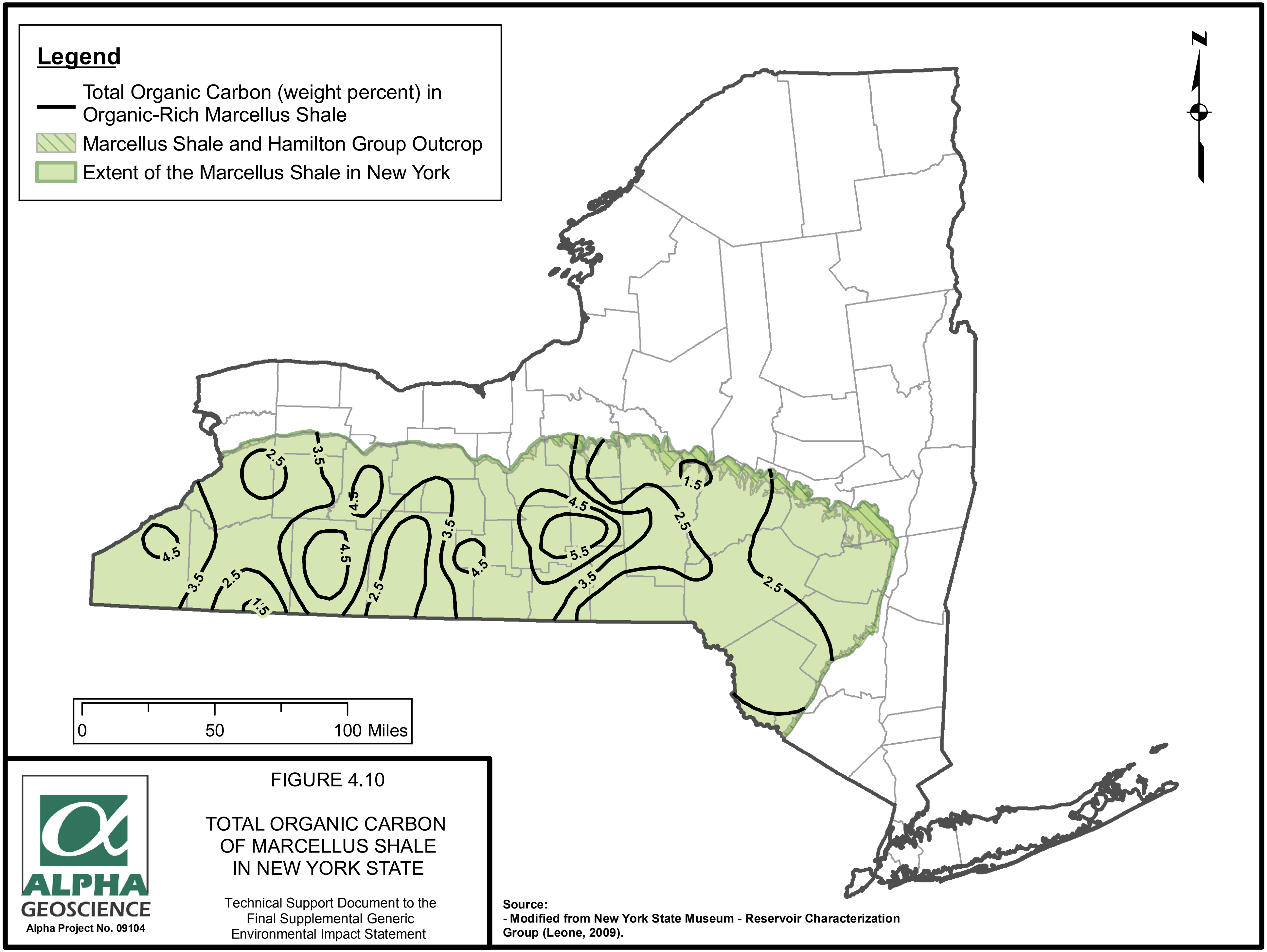

FIGURE 4.10

TOTAL ORGANIC CARBON OF MARCELLUS SHALE IN NEW YORK STATE

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

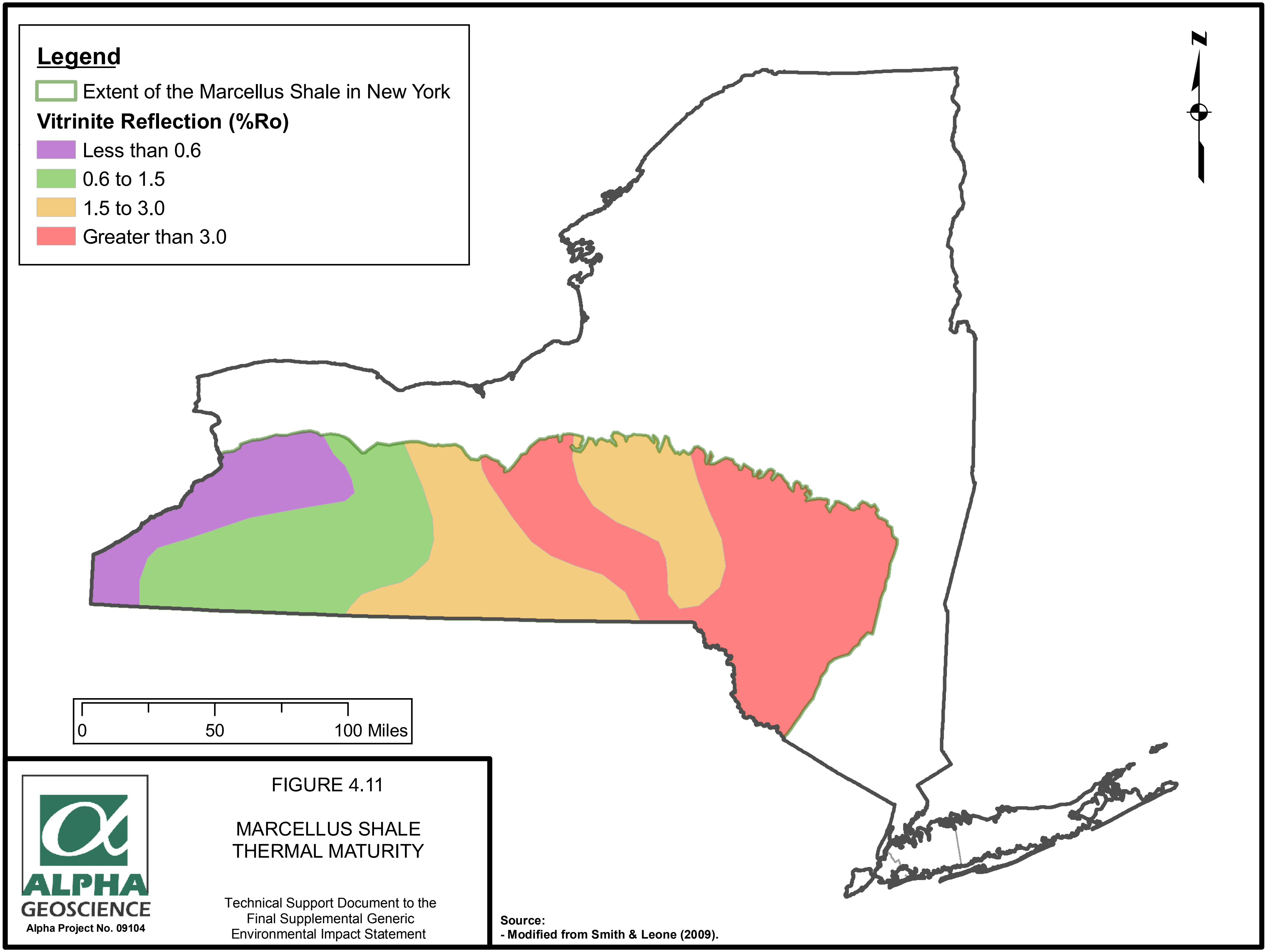

FIGURE 4.11

MARCELLUS SHALE THERMAL MATURITY

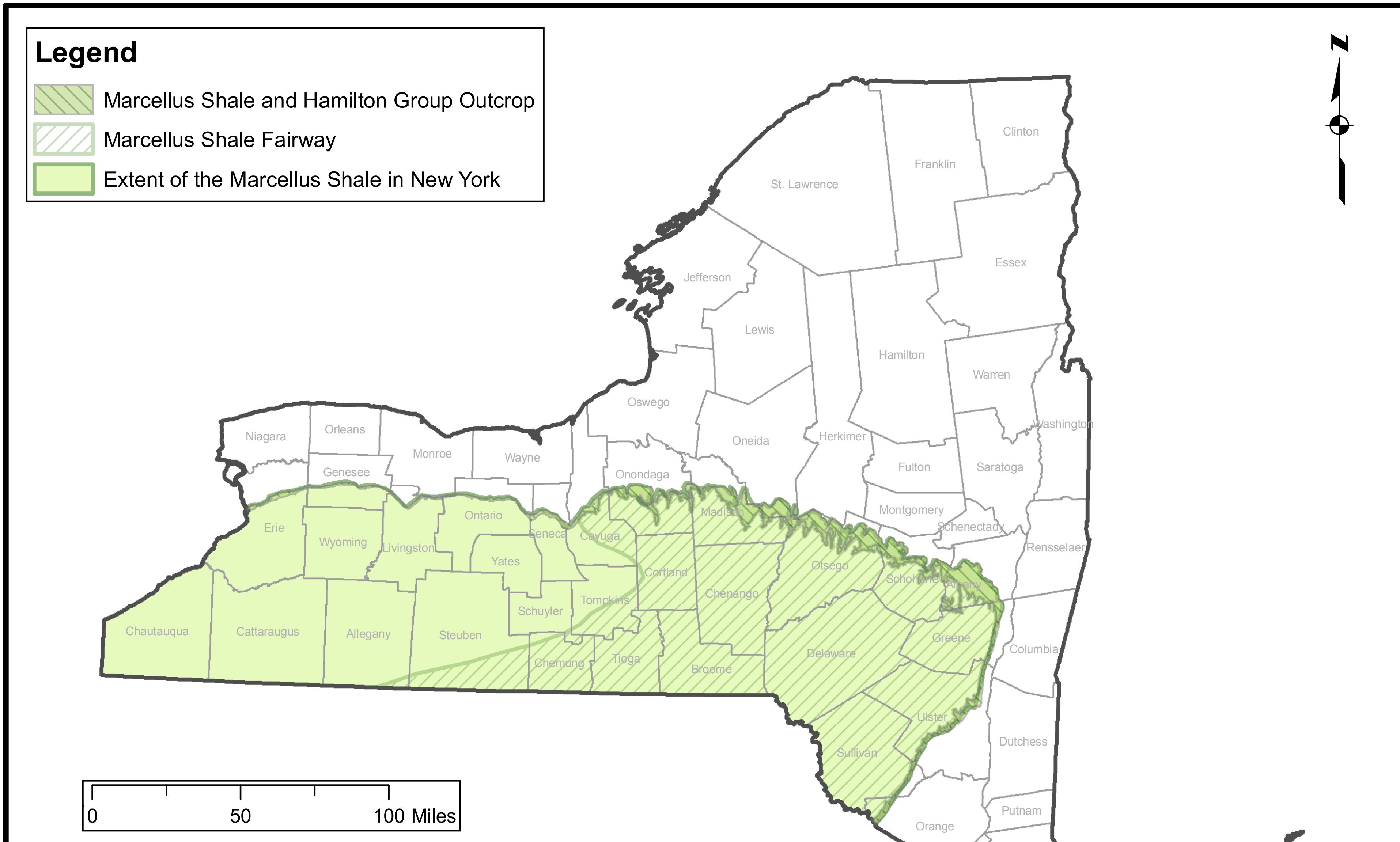

FIGURE 4.12

MARCELLUS SHALE FAIRWAY IN NEW YORK STATE

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

In 2011, the USGS estimated a mean of 84.2 Tcf of technically recoverable undiscovered natural gas reserves in the Marcellus Shale in the Appalachian Basin, more than a 40-fold increase from its 2002 estimate of 1.9 Tcf. Engelder had previously estimated a 50% probability that 489 Tcf of gas would be produced basin-wide from the Marcellus after a 50-year decline, and assigned 71.9 Tcf of that total to 17 counties in New York.95 Engelder's basin-wide estimate appears to include both proven and undiscovered reserves. While Engelder's methodology is based on both geology and published information about initial production rates and production decline from actual wells in Pennsylvania, the USGS describes its approach as based on recognized geologic characteristics of the formation. There is insufficient information available to determine the validity of comparing these projections, but it is common for projections of these types to vary, as a function of the prevailing technologies and knowledge base associated with a given resource.

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. 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.

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 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.

[95] Engelder, 2009.

Figure 4.13 shows the locations of faults and other structures that may indicate the presence of buried faults in New York State.[96] 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 Allegheny orogenies that occurred 350 to 500 million years ago.[97] There is also 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.[98] 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.[99] 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 50-year period). The areas around New York City, Buffalo, and northern-most New York have a moderate to high seismic hazard class ratings (2% probability of exceeding 12 to 40 %g in a 50-year period).

[96] Alpha, 2009, p. 138.

[97] Alpha, 2009, p. 138.

[98] Alpha, 2009, p. 139.

[99] Alpha, 2009, p. 139.

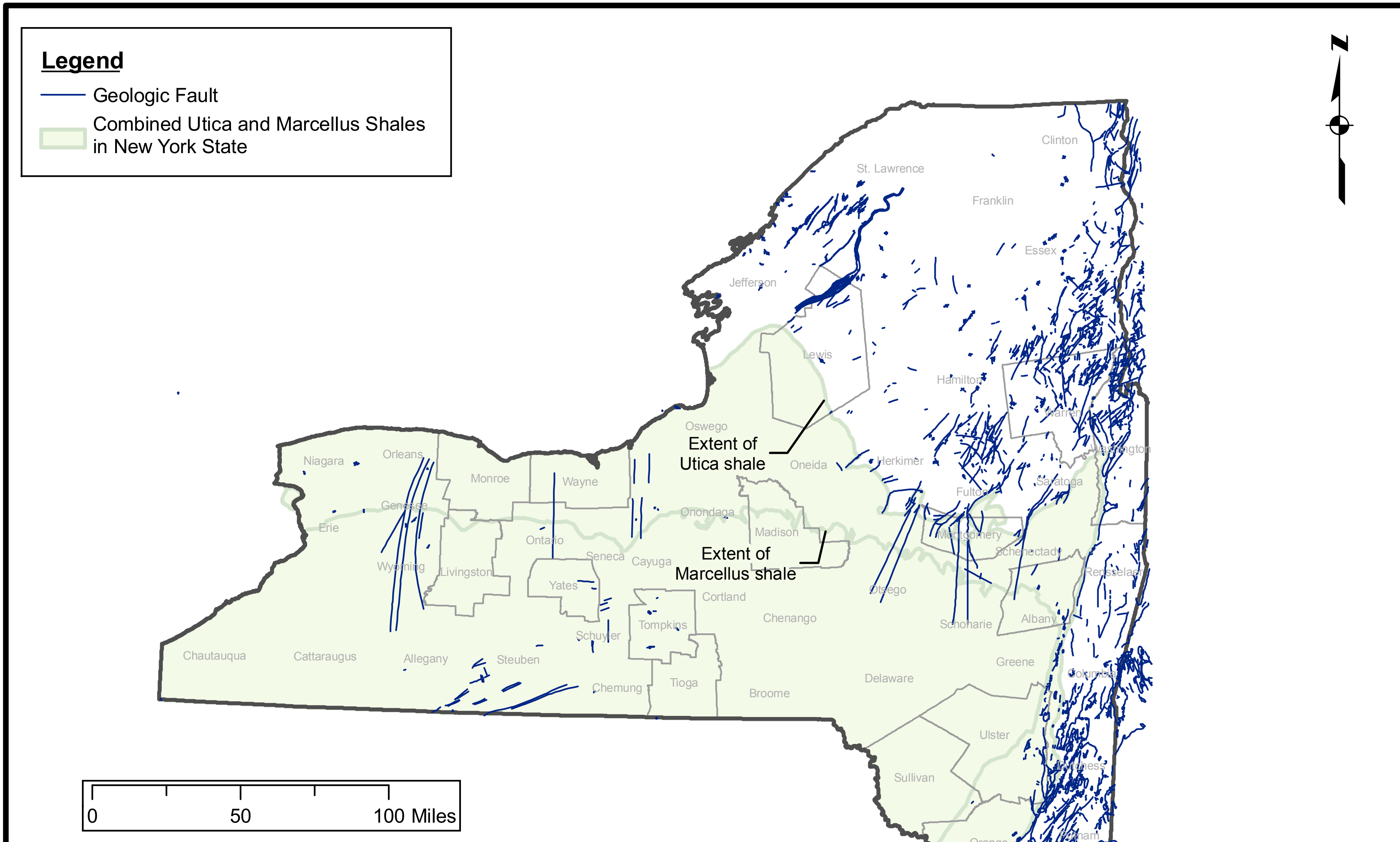

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FIGURE 4.13

MAPPED GEOLOGIC FAULTS IN NEW YORK STATE

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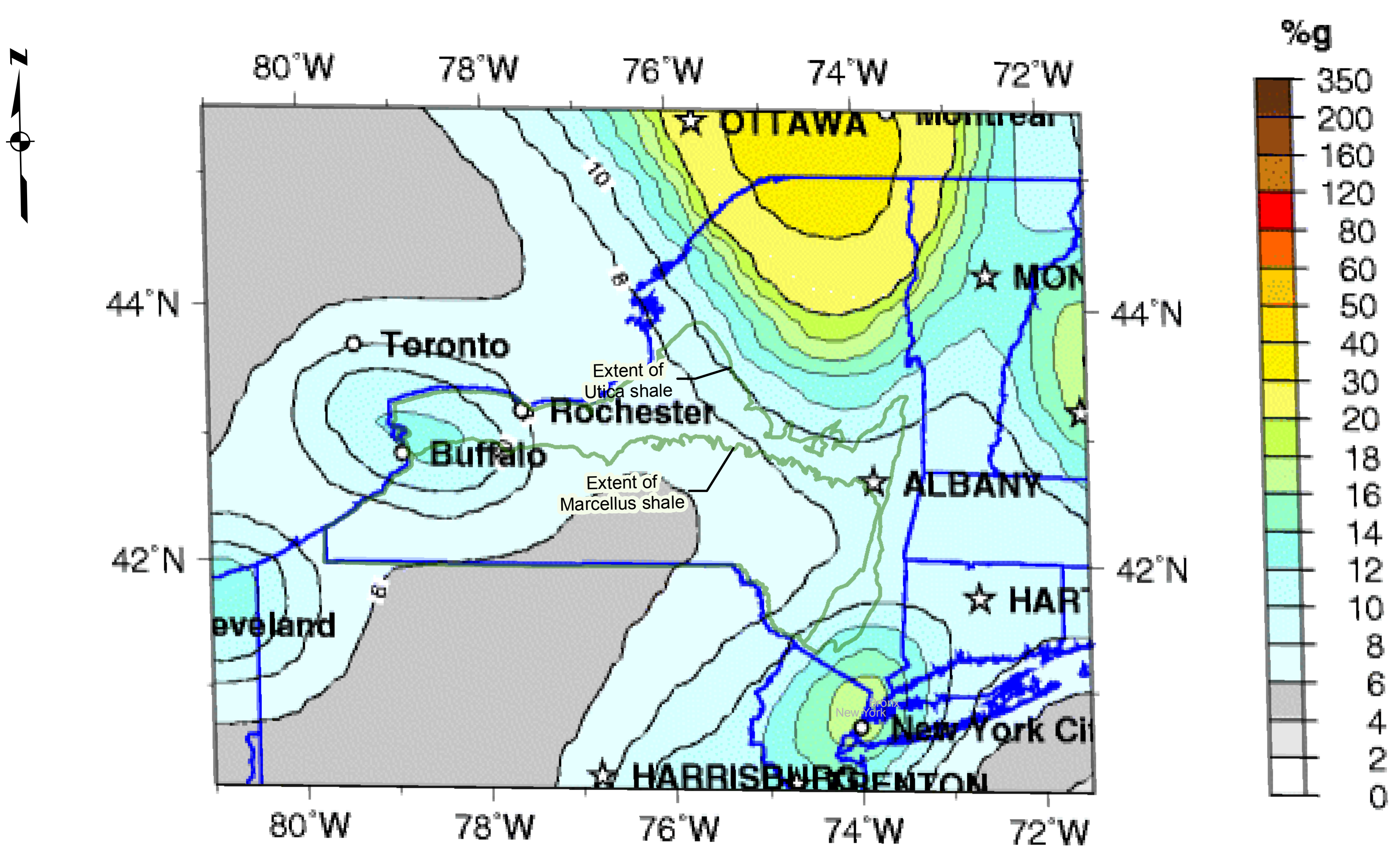
Note:
- Geologic fault features shown were complied by Isachsen and McKendree (1977) and exclude brittle structures identified as drillholes, topographic, and tonal linear features.



Approximate Scale

0 50 100 Miles

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FIGURE 4.14

NEW YORK STATE
SEISMIC HAZARD MAP

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

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 with a magnitude less than 7 and both scales are logarithmic; an increase of two units of magnitude on the Richter scale 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 in 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.[100] 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

[100] Alpha, 2009, p. 140.

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 Plattsburgh, Clinton County.[101] 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.[102]

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).

Induced seismicity refers to seismic events triggered by human activity such as mine blasts, nuclear experiments, and fluid injection, including hydraulic fracturing.[103] 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.

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[101] Alpha, 2009, p. 140.

[102] Alpha, 2009, p. 140.

[103] Alpha, 2009, p. 138.

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

Hydraulic fracturing releases energy during the fracturing process at a level substantially below that of small, naturally occurring, earthquakes. However, some of the seismic events shown on Figure 4.15 are known or suspected to be triggered by other types of 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.[104] 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[105] 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 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

[104] Alpha, 2009, p. 141.

[105] Alpha, 2009, p. 141.

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 ANSS, 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.[106] 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.[107]

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[106] Alpha, 2009, p. 142.

[107] Alpha, 2009, p. 143.

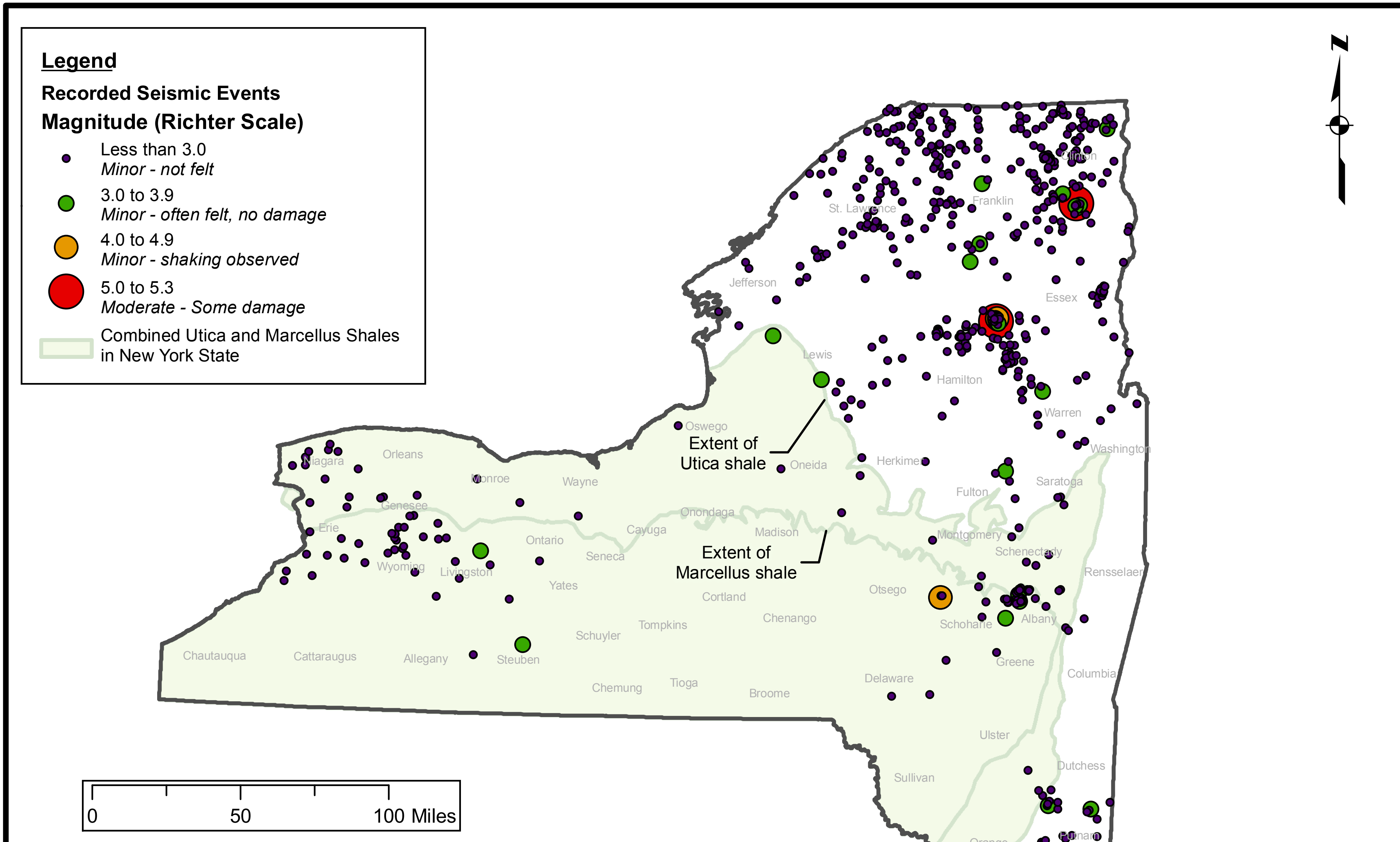

FIGURE 4.15

SEISMIC EVENTS IN NEW YORK STATE (1970 to 2009)

Technical Support Document to the Final Supplemental Generic Environmental Impact Statement

ALPHA GEOSCIENCE
Alpha Project No. 09104

Notes:
- Seismic events recorded December 13, 1970 through July 28, 2009.
- Lamont-Doherty Cooperative Seismographic Network, 2009 (http://almaty.ldeo.columbia.edu:8080/data.search.html)

4.6 Naturally Occurring Radioactive Materials (NORM) in Marcellus Shale

NORM is present to varying degrees in virtually all environmental media, including rocks and soils. 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 is known to contain concentrations of 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 having the potential to concentrate NORM need to come under regulatory oversight to ensure adequate protection of workers, the general public and the environment.

Chapter 5 includes radiological information (sampling results) from environmental media at various locations in the Appalachian Basin. Radiological data for the Marcellus in New York were derived from: a) drill cuttings and core samples from wells drilled through or completed in the Marcellus; and b) production brine from vertical wells completed in the Marcellus. Radiological data for the Marcellus in Pennsylvania and West Virginia were derived from: a) drill cuttings from wells completed in the Marcellus in Pennsylvania; and b) flowback water analyses provided by operators of 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.

4.7 Naturally Occurring Methane in New York State

The presence of naturally occurring methane in ground seeps and water wells is well documented throughout New York State. Naturally-occurring methane can be attributed to swampy areas or where bedrock and unconsolidated aquifers overlie Devonian-age shales or other gas-bearing formations. The highly fractured Devonian shale formations found throughout western New York are particularly well known for shallow methane accumulations. In his 1966 report on the Jamestown Aquifer, Crain explained that natural gas could occur in any water well in the area "which ends in bedrock or in unconsolidated deposits overlain by fine-grained confining material. Depth is not of primary importance because pockets of gas may occur in the bedrock at nearly any depth." [108] Upper Devonian gas bearing rocks at or near the surface extend across the southern tier of New York from Chautauqua and Erie Counties, east to Delaware and Sullivan counties (Figure 4.3).

As noted below, early explorers and water well drillers in New York reported naturally occurring methane in regions not then associated with natural gas well drilling activity. "Methane can occur naturally in water wells and when it does, it presents unique problems for water well drilling contractors. The major concern relates to flammable and explosive hazards associated with methane."[109] Gas that occurs naturally in shallow bedrock and unconsolidated sediments has been known to seep to the surface and/or contaminate water supplies including water wells. Often landowners are not aware of the presence of methane in their well. Methane is a colorless, odorless gas, and is generally considered non-toxic but there could be an explosive hazard if gas is present in significant volumes and the water well is not properly vented.

The existence of naturally occurring methane seeps in New York has been known since the mid 1600s. In August 1669 Rene Robert Cavelier de la Salle and Rene de Brehant de Galinee, while on their way to explore the Mississippi Valley, arrived in the Bristol Hills area of Ontario County, New York. It was here where the explorers observed natural gas flowing from joint planes in the Penn Yan Shale (Upper Devonian) at the foot of a falls over the Genundewa Limestone.[110] More recent studies and investigations have provided other evidence of naturally occurring methane in eastern New York. A private well in Schenectady County was gaged at 158 MMcf/d of natural gas by the Department in 1965. The well provided natural gas for the owner's domestic use for 30 years.[111] In 1987 the Times Union reported that contaminants, including methane, were found in well water in the Orchard Park subdivision near New Scotland, Albany County. Engineers from the Department reported the methane as "natural occurrences found in shale bedrock deposits beneath the development."[112] Ten years later, in 1997, a Saratoga Lake couple disclosed to a news reporter the presence of methane gas in their water

[108] NYSDEC, 1992, GEIS, p. 10-6.

[109] Keech, D. et al, 1982, pp. 33-36.

[110] Wells, J. 1963.

[111] Kucewicz, J. 1997.

[112] Thurman, K. 1987.

well. The concentration of gas in the well water was concentrated enough for the owners to ignite the gas from the bathtub faucet.[113] According to a September 22, 2010 article in the Daily Gazette, water wells in the Brown Road subdivision, Saratoga County became contaminated with methane gas when water wells were "blasted" (fractured) to reach a greater supply of water.[114]

Methane contamination of groundwater is often mistakenly attributed to or blamed on natural gas well drilling and hydraulic fracturing. There are a number of other, more common, reasons that well water can display sudden changes in quality and quantity. Seasonal variations in recharge, stress on the aquifer from usage demand, and mechanical failures are some factors that could lead to degradation of well water.

Recently, as part of two separate complaint investigations in the towns of Elmira and Collins, New York, the Department documented that methane gas existed in the shallow aquifers at the two sites long before and prior to the exploration and development for natural gas[115, 116]. The comprehensive investigations included the following:

- Analysis of drilling and completion records of natural gas wells drilled near the water wells;
- Evaluation of well logs to ascertain cement integrity;
- Collection of gas samples for compositional analysis;
- Inspections of the water and natural gas wells; and
- Interviews with landowners and water well drillers.

Both investigations provided clear evidence that methane contamination was present in the area's water wells prior to the commencement of natural gas drilling operations.

Drilling and construction activities may have an adverse impact on groundwater resources. The migration of methane can contaminate well water supplies if well construction practices designed

[113] Kruse, M. 1997.

[114] Bowen, K. 2010.

[115] NYSDEC, 2011.

[116] NYSDEC, 2011.

to prevent gas migration are not adhered to. Chapter 6 discusses these potential impacts with mitigation measures addressed in Chapter 7.

In April 2011 researchers from Duke University (Duke) released a report on the occurrence of methane contamination of drinking water associated with Marcellus and Utica Shale gas development.[117] As part of their study, the authors analyzed groundwater from nine drinking water wells completed in the Genesee Group in Otsego County, New York for the presence of methane. Of the nine wells, Duke classified one well as being in an active gas extraction area (i.e., a gas well within 1 kilometer (km) of the water well), and the remaining eight in a non-active gas extraction area. The analysis showed minimal amounts of methane in this sample group, with concentrations significantly below the minimum methane action level (10 mg/L) to maintain the safety of structures and the public, as recommended by the U.S. Department of the Interior, Office of Surface Mining.[118] The water well located in the active gas extraction area had 5 to 10 times less methane than the wells located in the inactive areas.

The Department monitors groundwater conditions in New York as part of an ongoing cooperative project between the USGS and the Department's Division of Water (DOW).[119] The objectives of this program are to assess and report on the ambient ground-water quality of bedrock and glacial-drift aquifers throughout New York State. In 2010 water samples were collected from 46 drinking water wells in the Delaware, Genesee, and St. Lawrence River Basins. All samples were analyzed for dissolved methane gas using standard USGS protocols. The highest methane concentration from all samples analyzed was 22.4 mg/L from a well in Schoharie County; the average detected value was 0.79 mg/L.[120] These groundwater results confirm that methane migration to shallow aquifers is a natural phenomenon and can be expected to occur in active and non-active natural gas drilling areas.

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[117] Osborne, S. et al, 2011.

[118] Eltschlager, K. et al, 2001.

[119] http://www.dec.ny.gov/lands/36117.html.

[120] NYSDEC, 2011.

NEW YORK STATE OF OPPORTUNITY. Department of Environmental Conservation

Chapter 5

Natural Gas Development Activities & High-Volume Hydraulic Fracturing

Final

Supplemental Generic Environmental Impact Statement

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Chapter 5 - Natural Gas Development Activities & High-Volume Hydraulic Fracturing

FIGURES

TABLES

Photos

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

As noted in the 1992 GEIS, New York has a long history of natural gas production. The first gas well was drilled in 1821 in Fredonia, and the 40 Bcf of gas produced in 1938 remained the production peak until 2004 when 46.90 Bcf were produced. Annual production exceeded 50 Bcf from 2005 through 2008, dropping to 44.86 Bcf in 2009 and 35.67 Bcf in 2010. Chapters 9 and 10 of the 1992 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 1992 GEIS.

New York counties with actively producing gas wells reported in 2010 were: Allegany, Cattaraugus, Cayuga, Chautauqua, Chemung, Chenango, Erie, Genesee, Livingston, Madison, Niagara, Ontario, Oswego, Schuyler, Seneca, Steuben, Tioga, Wayne, Wyoming and Yates.

Hydraulic fracturing is a well stimulation technique which consists of pumping a fluid and a 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 1992 GEIS. It is estimated that as many as 90% of wells drilled in New York are hydraulically fractured. ICF International provides the following history:[121]

Hydraulic Fracturing Technological Milestones [122]	
Early 1900s	Natural gas extracted from shale wells. Vertical wells fractured 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-fractured wells
2002	Multi-stage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus Shale[123]
2005	Increased emphasis on improving the recovery factor
2007	Use of multi-well pads and cluster drilling

[121] ICF Task 1, 2009, p. 3.

[122] Matthews, 2008, as cited by ICF Task 1, 2009, p. 3.

[123] Harper, 2008, as cited by ICF Task 1, 2009, p. 3.

5.1 Land Disturbance

Land disturbance directly associated with high-volume hydraulic fracturing will consist primarily of constructed gravel access roads, well pads and utility corridors. According to the most recent industry estimates, the average total disturbance associated with a multi-well pad, including incremental portions of access roads and utility corridors, during the drilling and fracturing stage is estimated at 7.4 acres and the average total disturbance associated with a well pad for a single vertical well during the drilling and fracturing stage is estimated at 4.8 acres. As a result of required partial reclamation, this would generally be reduced to averages of about 5.5 acres and 4.5 acres, respectively, during the production phase. These estimates include access roads to the well pads and incremental portions of utility corridors including gathering lines and compressor facilities, and the access roads associated with compressor facilities. These associated roads and facilities are projected to account for, on average, about 3.95 acres of the land area associated with each pad for the life of the wells. During the long-term production phase, a multi-well pad itself would occupy about 1.5 acres, while a well pad for a single vertical well would occupy about 0.5 acre.[124,125]

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 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. Industry estimates that 90% of the wells used to develop the Marcellus Shale will be horizontal wells located on multi-well pads.[126]

Access road construction involves clearing the route and preparing the surface for movement of heavy equipment, or reconstruction or improvement of existing roads if present on the property

[124] ALL Consulting, 2010, pp. 14 – 15.

[125] Cornue, 2011.

[126] ALL Consulting, 2010, pp. 7 – 15.

being developed. Ground surface preparation for new roads typically involves staking, grading, stripping and stockpiling of topsoil reserves, then 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.

Access road widths would generally range from 20 to 40 feet during the drilling and fracturing phase and from 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.

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. Industry estimates an average access road size of 0.27 acre,[127] which would imply an average length of about 400 feet for a 30-foot wide road. Permit applications for horizontal Marcellus wells received by the Department prior to publication of the 2009 draft SGEIS indicated road lengths ranging from 130 feet to approximately 3,000 feet.

Photo 5.1, Photo 5.2, Photo 5.3, and Photo 5.4 depict typical wellsite access roads.

[127] Cornue, 2011.

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

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 centralized water storage or handling facilities may reduce acreage requirements for individual well pads.[128]

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.[129] 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 staking, grading, stripping and stockpiling of topsoil reserves, then 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) 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, though fewer pads should be needed overall.[130] A larger well pad

[128] ICF Task 2, 2009, pp. 4-5.

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

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

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 1992 GEIS.

Industry estimates the average size of a multi-well pad for the drilling and fracturing phase of operations at 3.5 acres.[131] Average production pad size, after partial reclamation, is estimated at 1.5 acres for a multi-well pad.[132] Permit applications for horizontal wells received by the Department prior to publication of the 2009 draft SGEIS indicated multi-well pads ranging in size 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.

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.[133] 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.

Photo 5.5, Photo 5.6, and Photo 5.7 depict typical Marcellus well pads, and Figure 5.1 is a schematic representation of a typical drilling site.

[131] Cornue, 2011.

[132] ALL Consulting, 2010, p. 15.

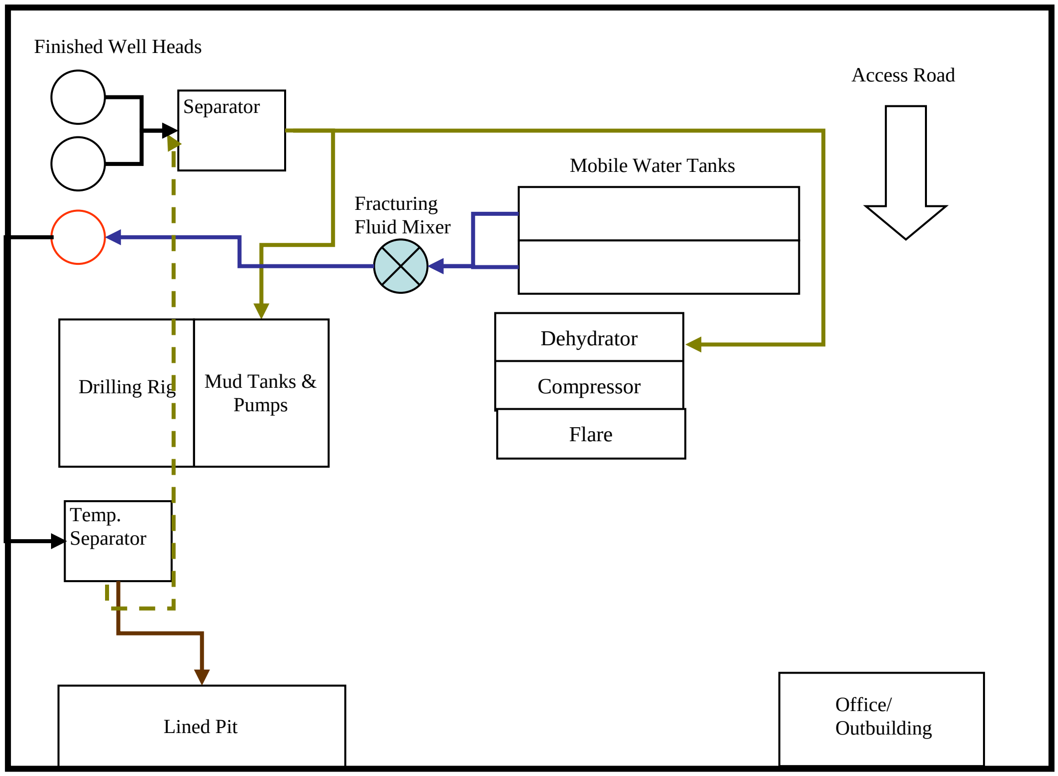
[133] ICF Task 2, 2009, p. 4.

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

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)

5.1.3 Utility Corridors

Utility corridors associated with high-volume hydraulic fracturing will include acreage used for potential water lines, above ground or underground electrical lines, gas gathering lines and compressor facilities, with average per-well pad acreage estimates as follows:

- 1.35 acres for water and electrical lines;
- 1.66 acres for gas gathering lines; and

- 0.67 acre for compression (because a compressor facility will service more than one well pad, this estimate is for an *incremental* portion assigned to a single well pad of a compressor facility and its associated sales line and access roads).[134]

Gathering lines may follow the access road associated with the well pad, so clearing and disturbance for the gathering line may be conducted during the initial site construction phase, thereby adding to the access road width. For example, some proposals include a 20-foot access road to the well pad with an additional 10-foot right-of-way for the gathering line.

Activities associated with constructing compressor facility pads are similar to those described above for well pads.

5.1.4 Well Pad Density

5.1.4.1 Historic Well Density

Well operators reported 6,732 producing natural gas wells in New York in 2010, approximately half of which (3,358) are in Chautauqua County. With 1,056 square miles of land in Chautauqua County, 3,358 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 5,490 permits to drill in Chautauqua County between 1962 and June 30, 2011, or five permits per square mile. Of those permits, 62% (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, 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 1992 GEIS, it is worthwhile to note that this pre-1992 drilling rate and site density were part of the experience upon which the 1992 GEIS and its findings are based.

[134] Cornue, 2011.

Photo 5.8, Photo 5.9, Photo 5.10, and Photo 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.

5.1.4.2 Anticipated Well Pad Density

The number of wells and well sites that may exist per square mile is dictated by gas 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, which are described below. Although the options include vertical drilling and single-well pad horizontal drilling, the Department anticipates that multi-well pad horizontal drilling (which results in the lowest density and least land disturbance) will be the predominant approach, for the following reasons:

- Industry estimates that 90% of the wells drilled to develop the Marcellus Shale will be horizontal wells on multi-well pads;[135]

- The addition to the ECL of provisions to address multi-well pad drilling was one of the primary objectives of the 2008 amendments, and was supported by the Department because of the reduced environmental impact;

- Multi-well pad drilling reduces operators' costs, by reducing the number of access roads and gathering lines that must be constructed as well as potentially reducing the number of equipment mobilizations; and

- Multi-well pad drilling reduces the number of regulatory hurdles for operators, because each well pad location would only need to be reviewed once for environmental concerns, stormwater permitting purposes and to determine conformance to SEQRA requirements, including the 1992 GEIS and the Final SGEIS.

[135] ALL Consulting, 2010, p. 7.

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.

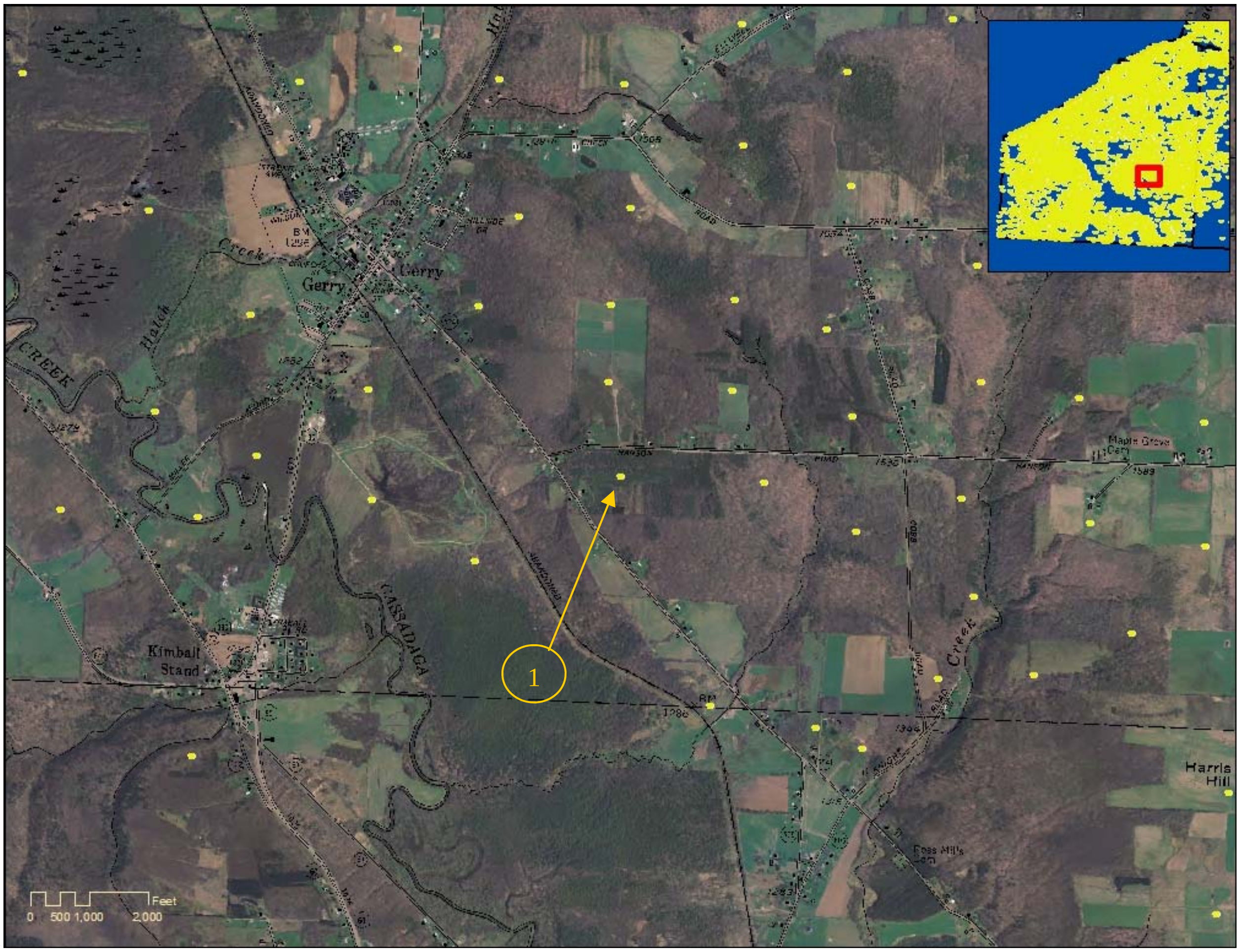


Photo 5.9 a & b The above map shows a portion of the Chautauqua County map, near Gerry. Well #1 (API Hole number 25468) shown in the photo to the right was drilled and completed for production in 2008 to a total depth of 4,095 feet. Of the other 47 Medina gas wells shown above, the nearest is approximately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

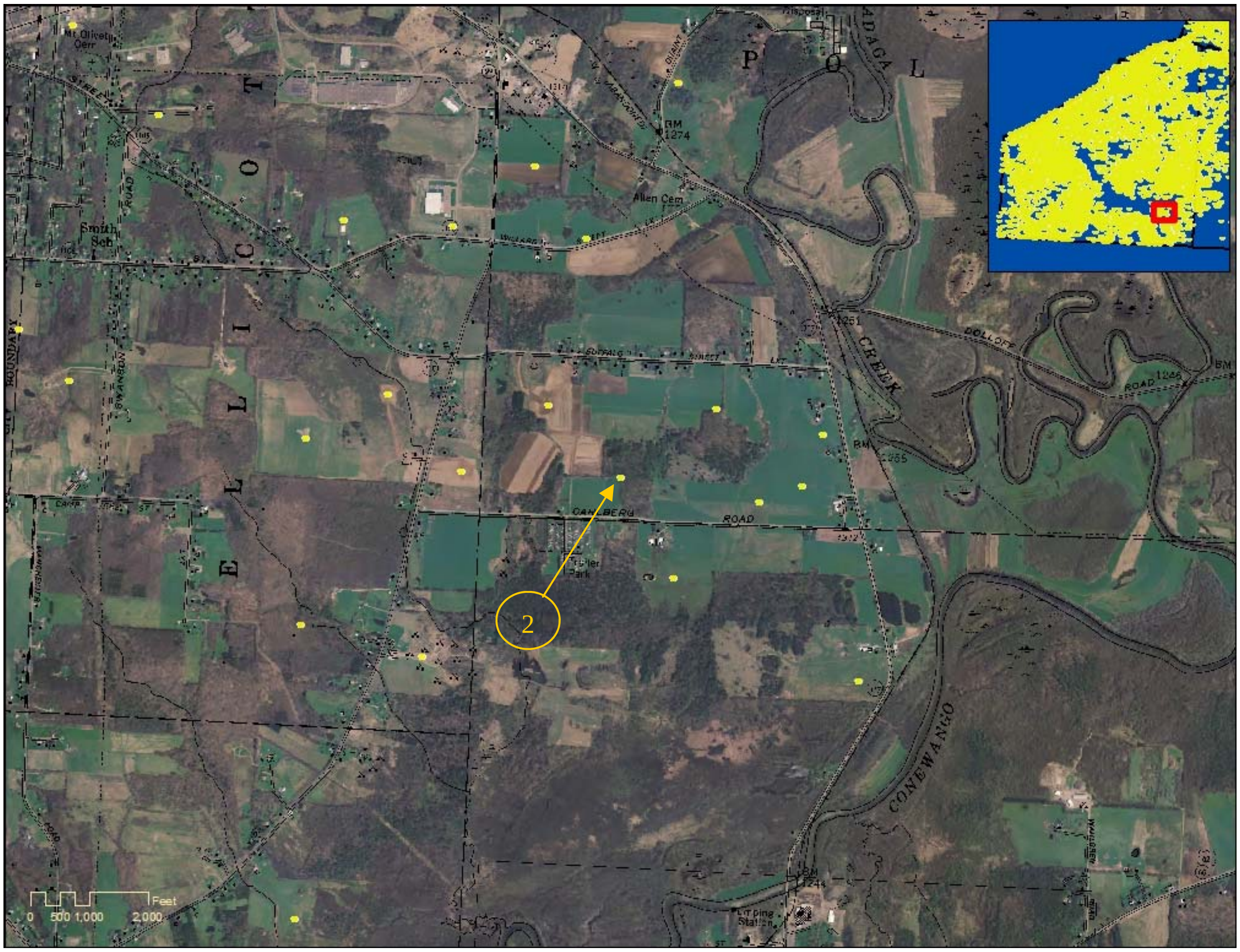


Photo 5.10 a & b This map shows 28 wells in the Town of Poland, Chautauqua County. Well #2 (API Hole number 24422) was drilled in 2006 to a depth of 4,250 feet and completed for production in 2007. The nearest other well is 1,700 feet away.

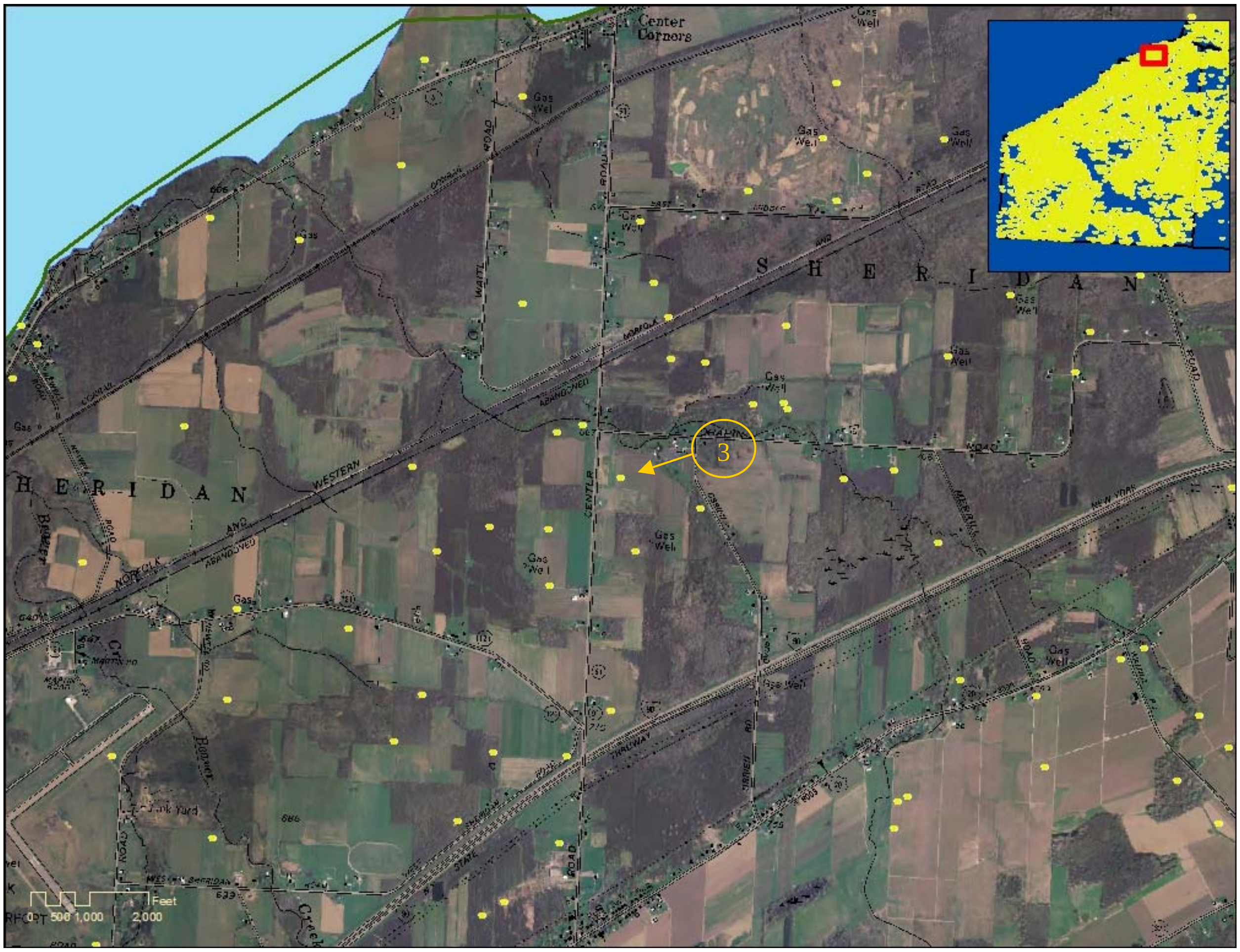


Photo 5.11 a & b The map above shows 77 wells. Well #3 (API Hole number 16427) identified in the map above, and shown in the photo below, was completed in the Town of Sheridan, Chautauqua County in 1981 and was drilled to a depth of 2,012 feet. The map indicates that the nearest producing well to Well #3 is 1/4 mile away.

Vertical Wells

Statewide spacing for vertical shale wells provides for one well per 40-acre spacing unit.[136] 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,[137] economic and technological considerations favor the use of horizontal drilling for shale gas development. As explained below, horizontal drilling necessarily results in larger spacing units and reduced well pad density. Industry estimates that 10% of the wells drilled to develop shale resources by high-volume hydraulic fracturing will be vertical.[138]

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 so that there will be 330 feet between the wellbore in the target formation and the spacing unit boundary. This means that the width of the spacing unit will be at least 660 feet and the distance within the target formation between wellbores will also 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 as an example would most likely be 4,000 feet or more, requiring substantially more than 40

[136] 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).

[137] GWPC, April 2009, pp. 46-47.

[138] ALL Consulting, 2010, p. 7.

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. Longer laterals would further reduce the number of well pads per square mile. The Department anticipates that the vast majority of horizontal wells will be drilled from common pads (i.e., multi-well pads), reducing surface disturbance even more.

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. Industry estimates that 90% of the wells drilled to develop shale resources by high-volume hydraulic fracturing will be horizontal;[139] as stated above, the Department anticipates that the vast majority of them will be drilled from multi-well pads. This method provides the most flexibility to avoid environmentally sensitive locations within the acreage to be developed and significantly reduces the number of needed well pads and associated roads.

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.[140] For example, a spacing of 40 acres per well for vertical shale gas wells would result in, on average, of 70 – 80 acres of disturbance for the well pads, access roads and utility corridors (4.8 acres per well[141]) to develop an area of 640 acres. By contrast, a single well pad with 6 to 8 horizontal shale gas wells could access all 640 acres with an average of 7.4 acres of total land disturbance. Table 5.1 below provides another comparison between the well pad acreage disturbed within a 10-square mile

139 ALL Consulting, 2010, p. 7.

140 Alpha, 2009, p. 6-2.

141 ALL Consulting, 2010, p. 14.

area completely developed by multi-well pad horizontal drilling versus single-well pad vertical drilling.[142]

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 (Updated July 2011)

Spacing Option	**Multi-Well 640 Acre**	**Single-Well 40 Acre**
Number of Pads	10	160
Total Disturbance - Drilling Phase	74 Acres (7.4 acres per pad)	768 Acres (4.8 ac. per pad)
% Disturbance - Drilling Phase	1.2%	12%
Total Disturbance - Production Phase	15 Acres (1.5 ac. per pad)	80 Acres (0.5 ac. per pad)
% Disturbance - Production Phase	0.23%	1.25%

It is possible that a single well-pad could be positioned to site wells to reach adjacent units, thereby developing 1,280 acres or more without increasing the land disturbance described above for multi-well pads. Use of longer lateral wellbores is another potential method for developing larger areas with less land disturbance.[143]

Variances or Non-Conforming Spacing Units

The ECL 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 particular spacing order will 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

[142] NTC, 2009, p. 29, updated with information from ALL Consulting, 2010.

[143] ALL Consulting, 2010, p. 87.

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 1992 GEIS. The second is that multiple wells are likely to 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 1992 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 or directional drilling deep within the earth. 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.

Current drilling technology for onshore consolidated strata results in maximum lateral lengths that do not greatly exceed the depth of the well. For example, a 5,000-foot deep well would generally not have a lateral length of significantly greater than 5,000 feet.[144] This may change,

[144] ALL Consulting, 2010, pp. 87-88.

however, as drilling technology continues to evolve. The length of the horizontal wellbore can also be affected by the operator's lease position or compulsory integration status within the spacing unit, the configuration of the approved spacing unit and wellbore paths, and other factors which influence well design.

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 1992 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, and may be used for drilling wells in the Marcellus Shale and other low-permeability reservoirs.

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 (in sequence) to drill a well, a smaller rig of similar dimensions to the typical rotary rigs described in the 1992 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 1992 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 (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, case, and cement the surface hole. This event generally takes about 8 to12 hours. The dimensions of this rig would be consistent with what is described in the 1992 GEIS. The second rig for drilling the remainder of the vertical hole would also be consistent with 1992 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, as noted above, be the only one that might exceed 1992 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.

An important component of the drilling rig is the blow-out prevention (BOP) system. This system is discussed in the 1992 GEIS. In summary, BOP system on a rotary drilling rig is a pressure control system designed specifically to contain and control a “kick” (i.e., unexpected pressure resulting in the flow of formation fluids into the wellbore during drilling operations). Other than the well itself, the BOP system basically consists of four parts: 1) the blow-out preventer stack, 2) the accumulator unit, 3) the choke manifold, and 4) the kill line. Blow-out preventers are manually or hydraulically operated devices installed at the top of the surface casing. Within the blow-out preventer there may be a combination of different types of devices to seal off the well. Pipe rams contain two metal blocks with semi-circular notches that fit together around the outside of the drill pipe when it is in the hole to block movement of fluids around the pipe. Blind rams contain two rubber faced metal blocks that can completely seal off the hole when there is no drill pipe in it. Annular or "bag" type blowout preventers contain a resilient packing element which expands inward to seal off the hole with or without drill pipe. In accordance with 6 NYCRR §554.4, the BOP system must be maintained and in proper working order during operations. A BOP test program is employed to ensure the BOP system is functioning properly if and when needed.

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, 1992 GEIS-consistent rigs would be used to drill the vertical portion of the wellbore. The rig and its associated auxiliary equipment would typically move off the well before fracturing operations commence.

Photo 5.12, Photo 5.13, Photo 5.14, and Photo 5.15 are photographs of drilling rigs.

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. In New York, ECL 23 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, to prevent operators from holding acreage within large spacing units without fully developing the acreage.[145]

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 be about 3.5 acres.[146] The well pad is often centered in the spacing unit.

[145] ECL §23-0501.

[146] Cornue, 2011.

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

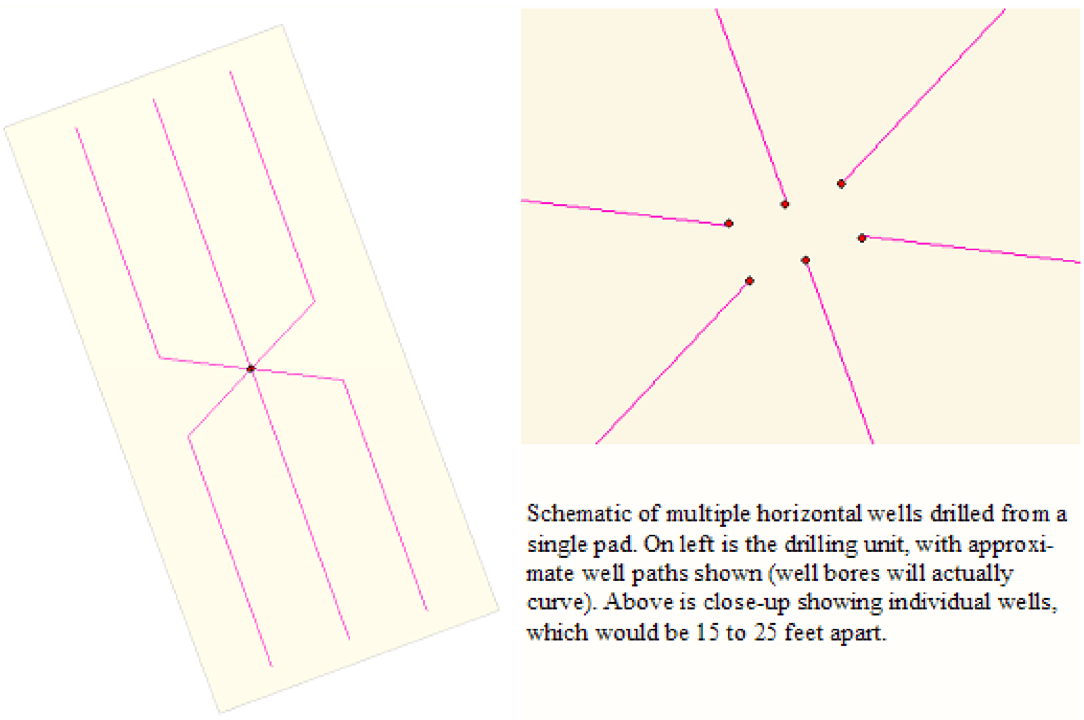
Photo 5.13 Double. Union Drilling Rig 48. Trenton-Black River well, Salo 1, Town of Barton, Tioga County NY. Source: NYS DEC 2008.

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.

Several factors determine the optimal drilling pattern within the target formation. These include geologic controls such as formation depth and thickness, mechanical and physical factors associated with the well construction program, production experience in the area, lease position and topography or surface restrictions that affect the size or placement of pads.[147] Often, evenly spaced parallel horizontal bores are drilled in opposite directions from surface locations arranged in two parallel rows. When fully developed, the resultant horizontal well pattern underground could resemble two back-to-back pitchforks [Figure 5.2]. Other, more complex patterns may also be proposed.

Figure 5.2 - Possible well spacing unit configurations and wellbore paths



Schematic of multiple horizontal wells drilled from a single pad. On left is the drilling unit, with approximate well paths shown (well bores will actually curve). Above is close-up showing individual wells, which would be 15 to 25 feet apart.

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, during a single mobilization. However, this may

[147] ALL Consulting, 2010, p. 88.

be affected by the timing of compulsory integration proceedings if wellbores are proposed to intersect unleased acreage.[148] 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 additional wells later, but within the required 3-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.

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 have been sealed behind cemented surface casing, and typically cemented intermediate casing, may be drilled with a mud that may be (i) water-based, (ii) potassium chloride/polymer-based with a mineral oil lubricant, or (iii) 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 and bit 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," (i.e., with compressed 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 1992 GEIS.

Drilling mud is contained and managed on-site through the rig's mud system which is comprised of a series of piping, separation equipment, and tanks. Photo 5.16 depicts some typical mud-system components. During drilling or circulating mud is pumped from the mud holding tanks at the surface down hole through the drill string and out the drill bit, and returns to the surface through the annular space between the drill string and the walls of the bore hole, where it enters the flowline and is directed to the separation equipment. Typical separation equipment includes

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

shale shakers, desanders, desilters and centrifuges which separate the mud from the rock cuttings. The mud is then re-circulated back into the mud tanks where it is withdrawn by the mud pump for continued use in the well. As described in the 1992 GEIS, used drilling mud is typically reconditioned for use at a subsequent well. The subsequent well may be located on the same well pad or at another location.

Photo 5.16 - Drilling rig mud system (blue tanks)

5.2.4 Cuttings

The rock chips and very fine-grained rock fragments removed by the drilling process and returned to the surface in the drilling fluid are known as “cuttings” and are contained and managed either in a lined on-site reserve pit or in a closed-loop tank system.[149] As described in Section 5.13.1, the proper disposal method for cuttings is determined by the composition of the fluid or fluids used during drilling. The proper disposal method will also dictate how the cuttings must be contained on-site prior to disposal, as described by Section 7.1.9.

[149] Adapted from Alpha, 2009, p. 133.

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 with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.

5.2.4.2 NORM in Marcellus Cuttings

To determine NORM concentrations and the potential for exposure to NORM contamination in Marcellus rock cuttings and cores (i.e., continuous rock samples, typically cylindrical, recovered during specialized drilling operations), 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). The results of these analyses are presented in Table 5.2a. 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 5.2b. Additional radiological analytical data for Marcellus Shale drill cuttings has been reported from Marcellus wells in Pennsylvania. Samples were collected from loads of drill cuttings being transported for disposal, as well as directly from the drilling rigs during drilling of the horizontal legs of the wells. The materials sampled were screened in-situ with a micro R meter, and analyzed by gamma ray spectroscopy. These data are provided in Table 5.3. As discussed further in Chapter 6, the results, which indicate levels of radioactivity that are essentially equal to background values, do not indicate an exposure concern for workers or the general public associated with Marcellus cuttings.

Table 5.2 - 2009 Marcellus Radiological Data

Table 5.2a Marcellus Radiological Data from Gamma Ray Spectroscopy Analyses					
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

Table 5.2b Marcellus Radiological Data from Geiger Counter Screening				
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 *
Well Sites	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 *
*maximum values detected				

Table 5.3 - Gamma Ray Spectroscopy

							Radionuclide Concentration (per wet mass)								
LAB ID#	Sample#	Date Collected	Sample Location	Material Type	Depth (feet)	Gamma* (uR/hr)	Radium-226 (pCi/g)			Thorium-232 (pCi/g)			Potassium-40 (pCi/g)		
Gas Drill Rig Cuttings															
738-1	31110A	3/11/2010	Bradford Co., Pa.	Marcellus shale	5942	8 / 10	2.4	±	0.2	0.5	±	0.1	12.9	±	1.0
738-2	31110B	3/11/2010	Bradford Co., Pa.	Hamilton Limestone	6562	5 / 5 **	1.1	±	0.1	0.9	±	0.1	17.8	±	1.0
738-3	31110C	3/11/2010	Bradford Co., Pa.	Marcellus shale	6687	11 / 8	4.3	±	0.2	0.9	±	0.1	15.8	±	0.9
738-5	31910A	3/19/2010	Tioga County, Pa.	Marcellus shale	6101	5 / 10	2.8	±	0.2	0.9	±	0.1	17.4	±	1.0
738-6	31910B	3/19/2010	Tioga County, Pa.	Marc. shale with Bayrite	6101	5 / 10	0.6	±	0.1	0.2	±	0.0	3.4	±	0.2
738-13	1-M1	3/2/2010	Landfill, Lowman, NY	transported gas rig cuttings	unk.	12	2.3	±	0.1	0.7	±	0.1	17.2	±	1.1
738-11	2-M2	3/2/2010	Landfill, Painted Post, NY	transported gas rig cuttings	unk.	12	0.9	±	0.1	1.2	±	0.1	16.7	±	1.1
738-12	3-M1	3/2/2010	Landfill, Angelica, NY	transported gas rig cuttings	unk.	12	2.7	±	0.2	0.8	±	0.1	12.6	±	0.8
						AVERAGE	**2.1**	±	**1.2**	**0.7**	±	**0.3**	**14.2**	±	**4.8**

5.2.5 Management of Drilling Fluids and Cuttings

The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases.

5.2.5.1 Reserve Pits on Multi-Well Pads

The 1992 GEIS describes the construction, use and reclamation of lined reserve pits, (also called "drilling pits" or "mud pits") to contain 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.[150] Chapter 7 discusses restrictions related to the use of reserve pits for managing drilling fluids and cuttings for high-volume hydraulic fracturing.

5.2.5.2 Closed-Loop Tank Systems

The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit. The containers may include tanks or bins that may have closed tops, open tops or open tops in combination with open sides. They may be stationary or truck-, trailer-, or skid-mounted. Regardless of the specific design of the containers, the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.

Depending on the drilling fluid utilized, a variety of types of separation equipment may be employed within a closed-loop tank system to separate the liquids from the cuttings prior to

[150] 6 NYCRR §554.1(c)(3).

capture within the system's containers. For air drilling employing a closed-loop tank system, shale shakers or other gravity-based equipment would likely be utilized to separate any formation fluids from the cuttings whereas mud drilling would employ equipment which is virtually identical to that of the drilling mud systems described previously in Section 5.2.3.

In addition to the equipment typically employed in a drilling mud system, operators may elect to utilize additional solids control equipment within the closed-loop system when drilling on mud, in an effort to further separate liquids from the cuttings. Such equipment could include but is not limited to drying shakers, vertical or horizontal rotary cuttings dryers, squeeze presses, or centrifuges[151] and when oil-based drilling muds are utilized the separation process may also include treatment to reduce surface tension between the mud and the cuttings.[152,153] The additional separation results in greater recovery of the drilling mud for re-circulation and produces dryer cuttings for off-site disposal.

Depending on the moisture-content of the cuttings, operators may drain or vacuum free-liquids from the cuttings container, or they may mix absorbent agents such as lime, saw dust or wood chips into the cuttings in order to absorb any free-liquids prior to hauling off-site for disposal. This mixing may take place in the primary capture container where the cuttings are initially collected following separation or in a secondary container located on the well pad.

Operators may simply employ primary capture containers which are suitable for capturing and transporting cuttings from the well site, or they may transfer cuttings from the primary capture container to a secondary capture container for transport purposes. If cuttings will be transferred between containers, front end loaders, vacuum trucks or other equipment would be utilized and all transfers will be required to occur in a designated transfer area on the well pad, which will be required to be lined.

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[151] ANL, 2011(a).

[152] The American Oil & Gas Reporter, August 2010, p. 92-93.

[153] Dugan, April 2008.

Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:

- Eliminates the time and expense associated with reserve pit construction and reclamation;
- Reduces the surface disturbance associated with the well pad;
- Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;
- Lowers mud replacement costs by capturing and re-circulating drilling mud;
- Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and
- Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.

5.3 Hydraulic Fracturing

The 1992 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,[154] 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 reservoir formation and the well operator's objectives. In the late 1990s, 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, which reviewed the current state of practice of hydraulic fracturing under contract with NYSERDA, states that the development of water fracturing technologies has reduced the quantity of chemicals required to hydraulically fracture target reservoirs and that

[154] 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 former Division of Solid and Hazardous Materials, now Materials Management. 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.

slickwater treatments have yielded better results than gel treatments in the Barnett Shale.[155] 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.[156] 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.[157] In addition, according to ICF, slickwater fracturing causes less formation damage than other techniques such as gel fracturing.[158]

Both slickwater fracturing and foam fracturing have been proposed for Marcellus Shale development. As foam fracturing is already addressed by the 1992 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.[159] 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 information has been evaluated by the Department's Division of Air Resources (DAR) and DOW as well as the NYSDOH's Bureau of Water Supply Protection and Toxic Substances Assessment. It has also been reviewed by technical consultants contracted by NYSERDA[160] 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.

[155] ICF Task 1, 2009. pp. 10, 19.

[156] ICF Task 1, 2009. pp. 10, 19.

[157] ICF Task 1, 2009. P. 12.

[158] ICF Task 1, 2009. P. 19.

[159] GWPC, April 2009, pp. 61-62.

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

Six service companies[161] and 15 chemical suppliers[162] have provided additive product compositional information to the Department in the form of product Material Safety Data Sheets (MSDSs)[163] and product composition disclosures consisting of chemical constituent names and their associated Chemical Abstract Service (CAS) Numbers,[164] as well as chemical constituent percent by weight information. Altogether, some compositional information is on file with the Department for 235 products, with complete[165] product composition disclosures and MSDSs on file for 167 of those products. Within these products are 322 unique chemicals whose CAS Numbers have been disclosed to the Department and at least 21 additional compounds whose CAS Numbers have not been disclosed due to the fact that many are mixtures. Table 5.4 is an alphabetical list of all products for which complete chemical information, including complete product composition disclosures and MSDSs, has been provided to the Department. Table 5.5 is an alphabetical list of products for which only partial chemical composition information has been provided to the Department, either in the form of product MSDSs or product composition disclosures which appear to be lacking information. Any product whose name does not appear within Table 5.4 or Table 5.5 was not evaluated in this SGEIS either because no chemical information was submitted to the Department or because the product has not been proposed for use in high-volume hydraulic fracturing operations in New York to date. These tables are included for informational purposes only and are not intended to restrict the proposal of additional additive products. See Chapter 8, Section 8.2.1.1 for a description of the permitting requirements related to fracturing additive information.

161 BJ Services, Frac Tech Services, Halliburton, Superior Well Services, Universal Well Services, Schlumberger.

162 Baker Petrolite, CESI/Floteck, Champion Technologies/Special Products, Chem EOR, Cortec, Fleurin Fragrances, Industrial Compounding, Kemira, Nalco, PfP Technologies, SNF Inc., Stepan Company, TBC-Brinadd/Texas United Chemical, Weatherford/Clearwater, and WSP Chemicals & Technology.

163 MSDSs are regulated by the Occupational Safety and Health Administration (OSHA)'s Hazard Communication Standard, 29 CFR 1910.1200(g) and are described in Chapter 8.

164 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.

165 The Department defines a complete product composition disclosure to include the chemical names and associated CAS Numbers of every constituent within a product, as well as the percent by weight information associated with each constituent of a product.

Table 5.4 - Fracturing Additive Products – Complete Composition
Disclosure Made to the Department (Updated July 2011)

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
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
BF-1
BF-7 / BF-7L
BioClear 1000 / Unicide 1000
Bio-Clear 200 / Unicide 2000

Product Name
Breaker FR
BXL-2, Crosslinker/ Buffer
BXL-STD / XL-300MB
Carbon Dioxide
CC-302T
CI-14
CL-31
CLA-CHEK LP
Claproteck CF
CLA-STA XP
Clay Treat PP
Clay Treat TS
Clay Treat-3C
Clayfix II
Clayfix II plus
CPF-X Plus
Cronox 245 ES
CS-250 SI
CS-650 OS, Oxygen Scavenger
CS-Polybreak 210
CS-Polybreak 210 Winterized
CT-ARMOR
EB-4L
Enzyme G-NE
FAC-1W / Petrostep FAC-1W
FAC-3W / Petrostop FAC-3W
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

Product Name
FR-56
FRP-121
FRW-14
GasPerm 1000
GBL-8X / LEB-10X / GB-L / En-breaker
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)
Hydrochloric Acid 10.1-15%
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 Agent J313
J534 / Urea Ammonium Nitrate Solution J534
J580 / Water GellingAgent 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

Product Name
Methanol
MO-67
Morflo III
MSA-II
Muriatic Acid 36%
Musol A
N002 / Nitrogen N_2
NCL-100
Nitrogen
Nitrogen, Liquid N_2
OptiKleen-WF
Para Clear D290 / ParaClean II
Paragon 100 E+
Parasperse
Parasperse Cleaner
PSI-720
PSI-7208
Salt
SAS-2
Scalechek LP-55
Scalechek LP-65
Scalechek SCP-2 / SCP-2
Scalehib 100 / Super Scale Inhibitor / Scale Clear SI-112
SGA II
Shale Surf 1000
Shale Surf 1000 Winterized
SI 103
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

Product Name
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 5.5 - Fracturing Additive Products – Partial Composition Disclosure to the Department (Updated July 2011)

Product Name
20 Degree Baume Muriatic Acid
AcTivator / 78-ACTW
AMB-100
B869 / Corrosion Inhibitor B869 / Corrosion Inhibitor A262
B885 / ClearFRAC LT B885 / ClearFRAC LT J551A
B892 / EZEFLO B892 / EZEFLO F110 Surfactant
CL-22UC
CL-28M
Clay Master 5C
Corrosion Inhibitor A261
FAW- 5
FDP-S798-05
FDP-S819-05
FE ACID
FR-48
FRW-16
FRW-18
Fracsal FR-143
Fracsal III
Fracsal NE-137
Fracsal Ultra
Fracsal Ultra-FM1
Fracsal Ultra-FM2
Fracsal Ultra-FM3
Fracsal Waterbase
Fracsal Waterbase-M1
FRW-25M
GA 8713
GBW-15L
GW-3LDF
HVG-1, Fast Hydrating Guar Slurry
ICA 400
ICP-1000
Inflo-102
Inhibisal Ultra CS-135
Inhibisal Ultra SI-141
J134L / Enzyme Breaker J134L
KCLS-2, KCL Substitute

Product Name
L065 / Scale Inhibitor L065
LP-65
Magnacide 575 Microbiocide
MSA ACID
Multifunctional Surfactant F105
Nitrogen, Refrigerated Liquid
Product 239
PS 550
S-150
SandWedge WF
SilkWater FR-A
Super TSC / Super Scale Control TSC
Super Sol 10/20/30
Ultra Breake-C
Ultra Breake-CG
Ultra Breake-M
Ultra-Breake-MG
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
WRR-5
WFR-C
XLBHT-1
XLBHT-2

Information in sections 5.4.1-3 below was compiled primarily by URS Corporation,[166] 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; and
- Minimal environmental effects.

5.4.2 *Classes of Additives*

Table 5.6 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.

[166] URS, 2011, p. 2-1 & 2009, p. 2-1.

Table 5.6 - Types and Purposes of Additives Proposed for Use in New York State (Updated July 2011)

Additive Type	**Description of Purpose**	**Examples of Chemicals**[167]
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
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 / Antibacterial Agent	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; 2,2-dibromo-3-nitrilopropionamide
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control /KCl	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 (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for Oxygen Scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate salts
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillates
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric 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;
Solvent	Additive which is soluble in oil, water & acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol; ethoxylated alcohol

[167] 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.

5.4.3 Composition of Fracturing Fluids

The composition of the fracturing fluid used may vary from one geologic basin or formation to another or from one area 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 products for each additive type; however, only one product of each type is typically utilized in any given hydraulic fracturing job. 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.

Sample compositions, by weight, of fracturing fluid are provided in Figure 5.3, Figure 5.4 and Figure 5.5. The composition depicted in Figure 5.3 is based on data from the Fayetteville Shale[168]while those depicted in Figure 5.4 and Figure 5.5 are based on data from Marcellus Shale development in Pennsylvania. Based on this data, between approximately 84 and 90 percent of the fracturing fluid is water; between approximately 8 and 15 % is proppant (Photo 5.17); the remainder, typically less than 1 % consists of chemical additives listed above.

Barnett Shale is considered to be the first instance of extensive high-volume hydraulic fracturing 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 as well as information provided by the industry[169] indicate that it is realistic to expect that the composition of fracture fluids used in the Marcellus Shale in New York would be similar to the fluids used in the Fayetteville Shale and the Marcellus Shale in Pennsylvania.

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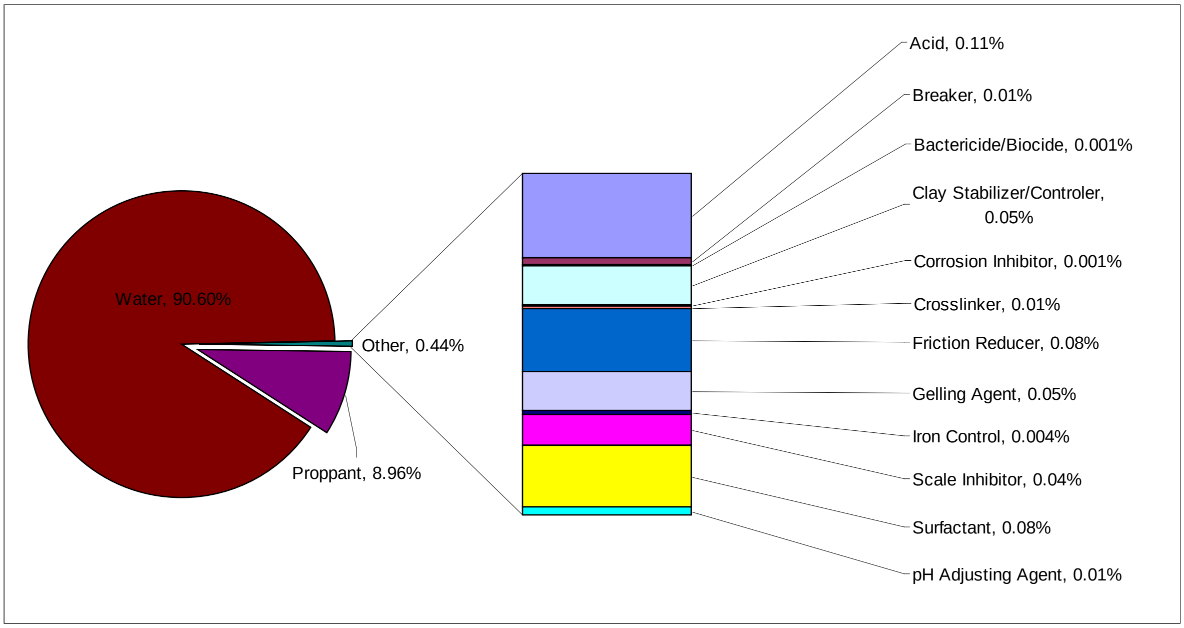
[168] Similar to the Marcellus Shale, the Fayetteville Shale is a marine shale rich in unoxidized carbon (i.e. a black shale). The two shales are at similar depths, and vertical and horizontal wells have been drilled/fractured at both shales.

[169] ALL Consulting, 2010, p. 80.

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

Figure 5.3 - Sample Fracturing Fluid Composition (12 Additives), by Weight, from Fayetteville Shale[170]



170 URS, 2009, p. 2-4.

Figure 5.4 - Sample Fracturing Fluid Composition (9 Additives), by Weight, from Marcellus Shale[171] (New July 2011)

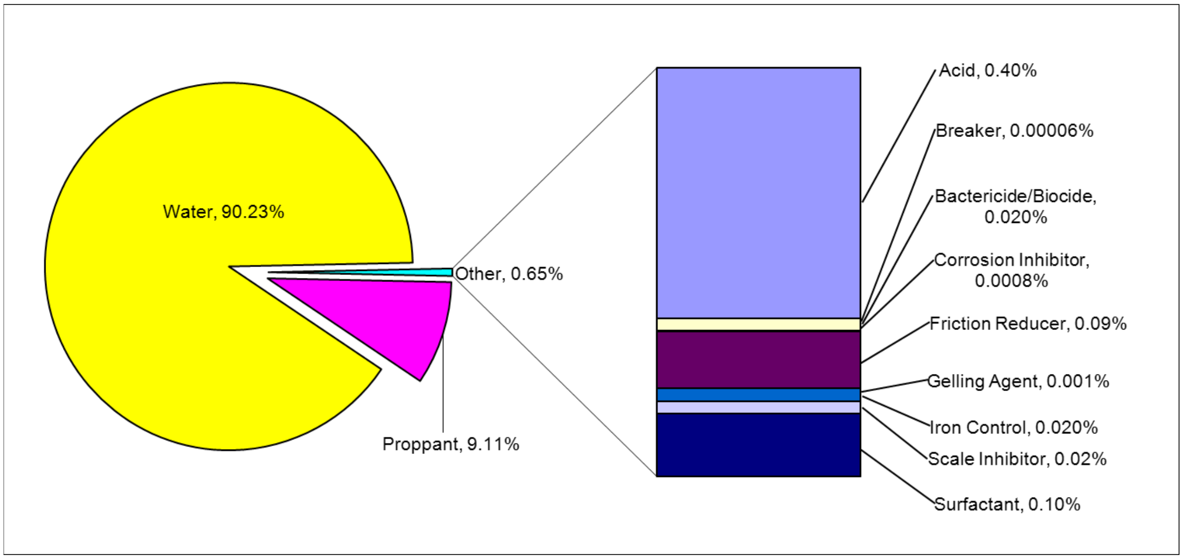
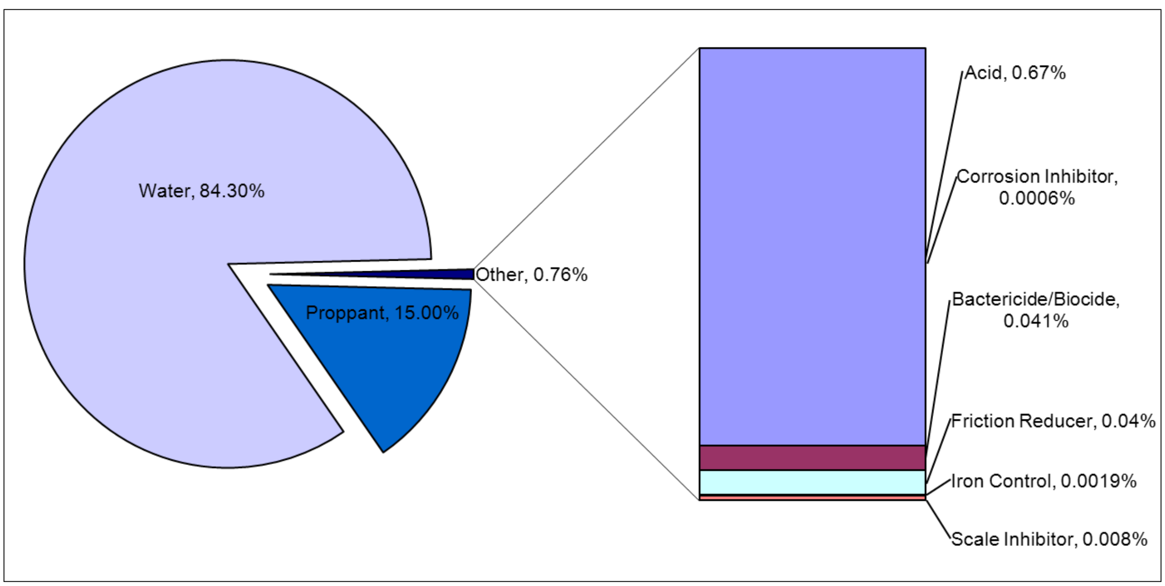


Figure 5.5 - Sample Fracturing Fluid Composition (6 Additives), by Weight, from Marcellus Shale[172] (New July 2011)



[171] URS, 2011, p. 2-4, adapted from ALL Consulting, 2010, p.81.

[172] URS, 2011, p.2-5, adapted from ALL Consulting, 2010, p. 81.

Each product within the 13 classes of additives may be made up of one or more chemical constituents. Table 5.7 is a list of chemical constituents and their CAS numbers, that have been extracted from product composition disclosures and MSDSs submitted to the Department for 235 products used or proposed for use in hydraulic fracturing operations in the Marcellus Shale in New York. It is important to note that several manufacturers/suppliers provide similar products (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.

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

Table 5.7 - Chemical Constituents in Additives[173,174,175] (Updated July 2011)

CAS Number[176]	Chemical Constituent
106-24-1	(2E)-3,7-dimethylocta-2,6-dien-1-ol
67701-10-4	(C8-C18) and (C18) Unsaturated Alkylcarboxylic Acid Sodium Salt
2634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one
95-63-6	1,2,4 trimethylbenzene
93858-78-7	1,2,4-Butanetricarboxylicacid, 2-phosphono-, potassium salt
123-91-1	1,4 Dioxane
3452-07-1	1-eicosene
629-73-2	1-hexadecene
104-46-1	1-Methoxy-4-propenylbenzene
124-28-7	1-Octadecanamine, N, N-dimethyl- / N,N-Dimthyloctadecylamine
112-03-8	1-Octadecanaminium, N,N,N-Trimethyl-, Chloride /Trimethyloctadecylammonium chloride
112-88-9	1-octadecene
40623-73-2	1-Propanesulfonic acid
1120-36-1	1-tetradecene
95077-68-2	2- Propenoic acid, homopolymer sodium salt

173 Table 5.7, is a list of chemical constituents and their CAS numbers that have been extracted from product composition disclosures and MSDSs submitted to the Department. It was compiled by URS Corporation (2011) and was adapted by the Department to ensure that it accurately reflects the data submitted.

174 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 would be used in a single well; the list of chemical constituents used in an individual well would be correspondingly smaller.

175 This list does not include chemicals that are exclusively used for drilling.

176 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[176]	Chemical Constituent
98-55-5	2-(4-methyl-1-cyclohex-3-enyl)propan-2-ol
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 / Ethylene glycol monobutyl ether / Butyl Cellusolve
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,
106-22-9	3,7 - dimethyl-6-octen-1-ol
5392-40-5	3,7- dimethyl-2,6-octadienal
115-19-5	3-methyl-1-butyn-3-ol
104-55-2	3-phenyl-2-propenal
127-41-3	4-(2,6,6-trimethyl-1-cyclohex-2-enyl)-3-buten-2-one
121-33-5	4-hydroxy-3-methoxybenzaldehyde
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
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer
25085-02-3	Acrylamide - Sodium Acrylate Copolymer / Anionic Polyacrylamide / 2-Propanoic Acid
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride / Ethanaminium, N, N, N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, polymer with 2-propenamide (9Cl)
68891-29-2	Alcohols C8-10, ethoxylated, monoether with sulfuric acid, ammonium salt
68526-86-3	Alcohols, C11-14-iso, C13-rich
68551-12-2	Alcohols, C12-C16, Ethoxylated / Ethoxylated alcohol
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent
64743-02-8	Alkenes

CAS Number[176]	Chemical Constituent
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt
9016-45-9	Alkylphenol ethoxylate surfactants
1327-41-9	Aluminum chloride
68155-07-7	Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)
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
12174-11-7	Attapulgite Clay
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
122-91-8	Benzenemethanol,4-methoxy-, 1-formate
1300-72-7	Benzenesulfonic acid, Dimethyl-, Sodium salt /Sodium xylene sulfonate
140-11-4	Benzyl acetate
76-22-2	Bicyclo (2.2.1) heptan-2-one, 1,7,7-trimethyl-
68153-72-0	Blown lard oil amine
68876-82-4	Blown rapeseed amine
1319-33-1	Borate Salt
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
1317-65-3	Calcium Carbonate
10043-52-4	Calcium chloride
1305-62-0	Calcium Hydroxide
1305-79-9	Calcium Peroxide
124-38-9	Carbon Dioxide
68130-15-4	Carboxymethylhydroxypropyl guar

CAS Number[176]	Chemical Constituent
9012-54-8	Cellulase / Hemicellulase Enzyme
9004-34-6	Cellulose
10049-04-4	Chlorine Dioxide
78-73-9	Choline Bicarbonate
67-48-1	Choline Chloride
91-64-5	Chromen-2-one
77-92-9	Citric Acid
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
14808-60-7	Crystalline Silica (Quartz)
7447-39-4	Cupric chloride dihydrate
1490-04-6	Cyclohexanol,5-methyl-2-(1-methylethyl)
8007-02-1	Cymbopogon citratus leaf oil
8000-29-1	Cymbopogon winterianus jowitt oil
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
34590-94-8	Dipropylene Glycol Methyl Ether
139-33-3	Disodium Ethylene Diamine Tetra Acetate
64741-77-1	Distillates, petroleum, light hydrocracked
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
111-42-2	Ethanol, 2,2-iminobis-
26027-38-3	Ethoxylated 4-nonylphenol
9002-93-1	Ethoxylated 4-tert-octylphenol

CAS Number[176]	Chemical Constituent
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
78330-21-8	Ethoxylated C11-14-iso, C13-rich alcohols
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
9036-19-5	Ethoxylated octylphenol
9005-67-8	Ethoxylated Sorbitan Monostearate
9005-70-3	Ethoxylated Sorbitan Trioleate
64-17-5	Ethyl alcohol / ethanol
100-41-4	Ethyl Benzene
93-89-0	Ethyl benzoate
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
8000-48-4	Eucalyptus globulus leaf oil
61790-12-3	Fatty Acids
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine
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
111-30-8	Glutaraldehyde
56-81-5	Glycerol / glycerine
9000-30-0	Guar Gum

CAS Number[176]	Chemical Constituent
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
64742-52-5	Hydrotreated heavy napthenic (petroleum) distillate
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
63-42-3	Lactose
8022-15-9	Lavandula hybrida abrial herb oil
64742-95-6	Light aromatic solvent naphtha
1120-21-4	Light Paraffin Oil
546-93-0	Magnesium Carbonate
1309-48-4	Magnesium Oxide
1335-26-8	Magnesium Peroxide
14807-96-6	Magnesium Silicate Hydrate (Talc)
1184-78-7	methanamine, N,N-dimethyl-, N-oxide
67-56-1	Methanol
119-36-8	Methyl 2-hydroxybenzoate
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched
8052-41-3	Mineral spirits / Stoddard Solvent
64742-46-7	Mixture of severely hydrotreated and hydrocracked base oil
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
68424-94-2	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine
7727-37-9	Nitrogen, Liquid form
68412-54-4	Nonylphenol Polyethoxylate
8000-27-9	Oils, cedarwood

CAS Number[176]	Chemical Constituent
121888-66-2	Organophilic Clays
628-63-7	Pentyl acetate
540-18-1	Pentyl butanoate
8009-03-8	Petrolatum
64742-65-0	Petroleum Base Oil
64741-68-0	Petroleum naphtha
101-84-8	Phenoxybenzene
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt
8000-41-7	Pine Oil
8002-09-3	Pine Oils
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
31726-34-8	Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-
9004-32-4	Polyanionic Cellulose
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized
56449-46-8	Polyethlene glycol oleate ester
9046-01-9	Polyethoxylated tridecyl ether phosphate
63428-86-4	Polyethylene glycol hexyl ether sulfate, ammonium salt
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
65997-18-4	Polyphosphate
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, /Propylene glycol
107-98-2	Propylene glycol monomethyl ether
68953-58-2	Quaternary Ammonium Compounds
62763-89-7	Quinoline,2-methyl-, hydrochloride
62763-89-7	Quinoline,2-methyl-, hydrochloride
15619-48-4	Quinolinium, 1-(phenylmethl),chloride
8000-25-7	Rosmarinus officinalis l. leaf oil
7631-86-9	Silica, Dissolved

CAS Number[176]	Chemical Constituent
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
68608-26-4	Sodium petroleum sulfonate
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
68442-77-3	Surfactant: Modified Amine
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
68917-35-1	Thuja plicata donn ex. D. don leaf oil
108-88-3	Toluene

CAS Number[176]	Chemical Constituent
81741-28-8	Tributyl tetradecyl phosphonium chloride
68299-02-5	Triethanolamine hydroxyacetate
68442-62-6	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
8042-47-5	White Mineral Oil
11138-66-2	Xanthan gum
1330-20-7	Xylene
13601-19-9	Yellow Sodium of Prussiate

Chemical Constituent
Aliphatic acids
Aliphatic alcohol glycol ether
Alkyl Aryl Polyethoxy Ethanol
Alkylaryl Sulfonate
Anionic copolymer
Aromatic hydrocarbons
Aromatic ketones
Citric acid base formula
Ethoxylated alcohol blend/mixture
Hydroxy acetic acid
Oxyalkylated alkylphenol
Petroleum distillate blend
Polyethoxylated alkanol
Polymeric Hydrocarbons
Quaternary amine
Quaternary ammonium compound
Salt of amine-carbonyl condensate
Salt of fatty acid/polyamine reaction product
Sugar
Surfactant blend
Triethanolamine

The chemical constituents listed in Table 5.7 are not linked to the product names listed in Table 5.4 and Table 5.5 because a significant number of product compositions have been properly justified as trade secrets within the coverage of disclosure exceptions of the Freedom of

Information Law [Public Officers Law §87.2(d)] and the Department's implementing regulation, 6 NYCRR § 616.7. The Department however, considers MSDSs to be public information ineligible for exception from disclosure as trade secrets or confidential business information.

5.4.3.1 Chemical Categories and Health Information

The Department 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. The Department provided DOH with fracturing additive product constituents based on 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 5.8, 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 5.8 - Categories based on chemical structure of potential fracturing fluid constituents.[177] (Updated July 2011)

Chemical	CAS Number
Amides	
Formamide	75-12-7
acrylamide	79-06-1
Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)	68155-07-7
Amines	
urea	57-13-6
thiourea	62-56-6
Choline chloride	67-48-1
tetramethyl ammonium chloride	75-57-0
Choline Bicarbonate	78-73-9
Ethanol, 2,2-Iminobis-	111-42-2
1-Octadecanaminium, N,N,N, Trimethyl-, Chloride (aka Trimethyloctadecylammonium choride)	112-03-8
1-Octadecanamine, N,N-Dimethyl- (aka N,N-Dimethyloctadecylamine)	124-28-7
monoethanolamine	141-43-5

[177] The chemicals listed in this table are organized in order of ascending CAS Number by category.

Chemical	CAS Number
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
Quaternary Ammonium Chloride	61789-71-7
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
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
Petrolatum	8009-03-8
White Mineral Oil	8042-47-5
stoddard solvent	8052-41-3
Distillates, petroleum, light hydrocracked	64741-77-1
petroleum naphtha	64741-68-0
Mixture of severely hydrotreated and hydrocracked base oil	64742-46-7
<u>Multiple names listed under same CAS#:</u> 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, mixture of severely hydrotreated and hydrocracked base oil	64742-47-8
naphtha, hydrotreated heavy	64742-48-9

Chemical	CAS Number
Multiple names listed under same CAS#: hydrotreated heavy napthenic distillate, Petroleum distillates	64742-52-5
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
diethylbenzene	25340-17-4
naphthalene bis(1-methylethyl)	38640-62-9
Alcohols & Aldehydes	
formaldehyde	50-00-0
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-(4-methyl-1-cyclohex-3-enyl)propan-2-ol	98-55-5
3-phenylprop-2-enal	104-55-2
2-ethyl-1-hexanol	104-76-7
3,7 - dimethyloct-6-en-1-ol	106-22-9
(2E)-3,7-dimethylocta-2,6-dien-1-ol	106-24-1
propargyl alcohol	107-19-7
ethylene glycol	107-21-1
Diethylene Glycol	111-46-6
3-methyl-1-butyn-3-ol	115-19-5
4-hydroxy-3-methyoxybenzaldehyde	121-33-5
5-methyl-2-propan-2-ylcyclohexan-1-ol	1490-04-6
3,7-dimethylocta-2,6-dienal	5392-40-5
Ethyloctynol	5877-42-9

Chemical	CAS Number
Glycol Ethers, Ethoxylated Alcohols & Other Ethers	
phenoxybenzene	101-84-8
1-methyoxy-4-prop-1-enylbenzene	104-46-1
propylene glycol monomethyl ether	107-98-2
ethylene glycol monobutyl ether	111-76-2
triethylene glycol	112-27-6
ethoxylated 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
dipropylene glycol methyl ether	34590-94-8
Trimethylolpropane, Ethoxylated, Propoxylated	52624-57-4
Polyethylene glycol-(alcohol) ethers	60828-78-6
Ethoxylated castor oil [PEG-10 Castor oil]	61791-12-6
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 C11-14-iso, C13-rich alcohols	78330-21-8
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

Chemical	CAS Number
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, Salts, Esters 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
ethyl benzoate	93-89-0
ethyl lactate	97-64-3
acetic anhydride	108-24-7
fumaric acid	110-17-8
ethyl 2-hydroxybenzoate	118-61-6
methyl 2-hydroxybenzoate	119-36-8
(4-methoxyphenyl) methyl formate	122-91-8
potassium acetate	127-08-2
sodium acetate	127-09-3
Disodium Ethylene Diamine Tetra Acetate	139-33-3
benzyl acetate	140-11-4
Trisodium Ethylenediamine tetraacetate	150-38-9
sodium benzoate	532-32-1
pentyl butanoate	540-18-1
potassium formate	590-29-4
pentyl acetate	628-63-7
ammonium acetate	631-61-8
Benzenesulfonic acid, Dimethyl-, Sodium salt (aka Sodium xylene sulfonate)	1300-72-7
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
Polyethoxylated tridecyl ether phosphate	9046-01-9
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

Chemical	CAS Number
Fatty acids, coco, reaction products with ethanolamine, ethoxylated	61791-08-0
fatty acid, coco, ethoxylated	61791-29-5
2-propenoic acid, telomer with sodium hydrogen sulfite	66019-18-9
fatty acides, c8-18 and c18-unsatd., sodium salts	67701-10-4
carboxymethylhydroxypropyl guar	68130-15-4
Blown lard oil amine	68153-72-0
Tall oil Fatty Acid Diethanolamine	68155-20-8
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
Modified Amine	68442-77-3
fatty acids, c-18-18 and c18-unsatd., compds with diethanolamine	68604-35-3
Sodium petroleum sulfonate	68608-26-4
Blown rapeseed amine	68876-82-4
Poly(oxy-1,2-ethanediyl), α-sulfo-ω-hydroxy-, c8-10-alkyl ethers, ammonium salts	68891-29-2
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
2-Phosphonobutane-1,2,4-tricarboxylic acid, potassium salt	93858-78-7
sodium alpha-olefin sulfonate	95371-16-7
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
<u>Multiple names listed under same CAS#:</u> oxirane, methyl-, polymer with oxirane, Ethylene Glycol-Propylene Glycol Copolymer	9003-11-6
Polyanionic Cellulose	9004-32-4
cellulose	9004-34-6
hydroxyethyl cellulose	9004-62-0
cellulase/hemicellulase enzyme	9012-54-8
hemicellulase	9025-56-3
xanthan gum	11138-66-2
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
TerPoly (Acrylamide-AMPS Acrylic Acid)	40623-73-2

Chemical	CAS Number
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
2- Propenoic acid, homopolymer sodium salt	95077-68-2
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
Magnesium Carbonate	546-93-0
Potassium Carbonate	584-08-7
Boric Anhydride (a.k.a. Boric Oxide)	1303-86-2
sodium tetraborate decahydrate	1303-96-4
Calcium Hydroxide	1305-62-0
Calcium Peroxide	1305-79-9
Magnesium Oxide	1309-48-4
Potassium Hydroxide	1310-58-3
sodium hydroxide	1310-73-2
Calcium Carbonate	1317-65-3
Borate Salt	1319-33-1
aluminum chloride, basic	1327-41-9
Magnesium Peroxide	1335-26-8
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

Chemical	CAS Number
nitrogen	7727-37-9
ammonium persulfate	7727-54-0
water	7732-18-5
sodium sulfate	7757-82-6
sodium chlorite	7758-19-2
sodium thiosulfate	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
Attapulgite Clay	12174-11-7
potassium borate	12714-38-8
Yellow Sodium of Prussiate	13601-19-9
potassium metaborate	13709-94-9
Magnesium Silicate Hydrate (Talc)	14807-96-6
crystalline silica (quartz)	14808-60-7
glassy calcium magnesium phosphate	65997-17-3
Polyphosphate	65997-18-4
silica gel	112926-00-8
synthetic amorphous, pyrogenic silica	112945-52-5
synthetic amorphous, pyrogenic silica	121888-66-2
Miscellaneous	
Sucrose	57-50-1
lactose	63-42-3
acetone	67-64-1
ethylene oxide	75-21-8
1,7,7-trimethylbicyclo[2.2.1]heptan-2one	76-22-2
chromen-2-one	91-64-5
1-octadecene	112-88-9
1,4-dioxane	123-91-1
(E)-4-(2,6,6-trimethyl-1-cyclohex-2-enyl)but-3-en-2-one	127-41-3
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
rosmarinus officinalis l. leaf oil	8000-25-7
oils, cedarwood	8000-27-9
cymbopogan winterianus jowitt oil	8000-29-1
Pine Oil	8000-41-7
eucalyptus globulus leaf oil	8000-48-4

Chemical	CAS Number
oils, pine	8002-09-3
cymbopogon citratus leaf oil	8007-02-1
lavandula hydrida abrial herb oil	8022-15-9
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
thuja plicata donn ex. D. don leaf oil	68917-35-1
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[178]	
belongs with amines	
proprietary quaternary ammonium compounds	NA
quaternary ammonium compound	NA
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, ethoxylated alcohols & other ethers	
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
mixture of ethoxylated alcohols	NA
nonylphenol ethoxylate	NA
oxyalkylated alkylphenol	NA
polyethoxylated alkanol	NA
Oxyalkylated alcohol	NA
belongs with organic acids, salts, esters and related chemicals	
Aliphatic acids derivative	NA
Aliphatic Acids	NA

[178] 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 the Department.

Chemical	CAS Number
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
Anionic copolymer	NA
Anionic 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
salt of amine-carbonyl condensate	NA
surfactant blend	NA
sugar	NA
polymeric hydrocarbon mixture	NA
water and inert ingredients	NA

Although exposure to fracturing additives would not occur absent 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. Toxicity testing data is quite limited for some chemicals, and less is known about their potential adverse effects. In particular, there is little meaningful information one way or the other about the potential impact on human health of chronic low level exposures to many of these chemicals, as could occur if an aquifer were to be contaminated as the result of a spill or release that is undetected and/or unremediated.

The overall risk of human health impacts occurring from hydraulic fracturing would depend on whether any human exposure occurs, such as, for example, in the event of a spill. If an actual contamination event such as a spill were to occur, more specific assessment of health risks would require obtaining detailed information specific to the event such as 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 data with existing drinking water standards or ambient air guidelines.[179] 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 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 xylenes 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

[179] 10 NYCRR Part 5: Drinking Water Supplies; Subpart 5-1: Public Water Systems, Maximum Contaminant Levels; Department Policy DAR-1: Guidelines for the Control of Toxic Ambient Air Contaminants.

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. However, 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 (also known as 2-butoxyethanol)] can affect the male reproductive system and red blood cell formation in laboratory animals at high exposure levels.

Alcohols and Aldehydes

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) affects the central nervous system.

Aldehydes are present in some fracturing fluid additive products, including corrosion inhibitors, scale inhibitors, surfactants and foaming agents. Aldehydes can be irritating to tissues when coming into direct contact with them. The most common symptoms include irritation of the skin, eyes, nose and throat, along with increased tearing. Formaldehyde is present in several additive products, although in most cases the concentration listed in the product is relatively low (< 1%) and is listed alongside a formaldehyde-based polymer constituent. Severe pain, vomiting, coma and possibly 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.

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, Esters 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 the Department are included in Table 5.8 under the following categories: polymers, miscellaneous chemicals that did not fit another chemical category and product constituents that were not identified by a CAS number. Readily available health effects information is lacking for many of these constituents, but one that is relatively well studied is 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 or toxicity data for closely- related chemicals.

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. Chemicals in products proposed for use in high-volume hydraulic fracturing include some that, based mainly on occupational studies or high-level exposures in laboratory animals, have been shown to cause effects such as carcinogenicity, mutagenicity, reproductive toxicity, neurotoxicity or organ damage. This information only indicates the types of toxic effects these chemicals can cause under certain circumstances but does not mean that use of these chemicals would cause exposure in every case or that exposure would cause those effects in every case. Whether or not people actually experience a toxic effect from a chemical depends on whether or not they experience any exposure to the chemical along with many other factors including, among others, the amount, timing, duration and route of exposure and individual characteristics that can contribute to differences in susceptibility.

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 scenarios associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the 1992 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 fracturing 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.[180] For informational purposes, Chapter 8 contains descriptions of applicable NYSDOT and USDOT regulations.

Transporting fracturing additives that are hazardous is comprehensively regulated under existing regulations. The regulated materials include the hazardous additives and mixtures containing threshold levels 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.[181]

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 13 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 Table 5.7 and Table 5.8 reflect the constituents of 235 products, typically no more than 12 products consisting of far fewer chemicals than listed would be present at one time at any given site.

[180] Alpha 2009, p. 31.

[181] Alpha 2009, p. 31.

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.[182]

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.

[182] Alpha, 2009, p. 35.

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;
- 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 inside boxes on the flat-bed; and
- Smaller double-bag systems stored inside boxes on the blending unit.

5.7 Source Water for High-Volume Hydraulic Fracturing

As discussed in Chapter 6, it is estimated, based on water withdrawals in the Susquehanna River Basin in Pennsylvania, that average water use per well in New York could be 3.6 million gallons. Operators could withdraw water from surface or ground water sources themselves or may purchase it from suppliers. The suppliers may include, among others, 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 to address potential environmental impacts are discussed in Chapter 7. Photo 5.19a and b depict a water withdrawal facility along the Chemung River in the northern tier of Pennsylvania.

Factors affecting usability of a given source include:[183]

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

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.

[183] URS, 2009, p. 7-1.

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 flue 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 could be delivered by truck or pipeline directly from the source to the well pad, or could 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. These mobile storage tanks provide temporary storage of fresh water, and preclude the need for installation of centralized impoundments. They are double-walled, wheeled tanks with sealed entry and fill ports on top and heavy-duty drain valves with locking mechanisms at the base. These tanks are similar in construction to the ones used to temporarily store flowback water; see Photo 5.7.

Potential environmental impacts related to water transportation, including the number and duration of truck trips for moving both fluid and temporary storage tanks, will be 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. See Section 8.2.2.2 for a description of the Department's existing regulatory program related to construction, operation and maintenance of such impoundments.

Photos 5.19 a & b Fortuna SRBC-approved Chemung River water withdrawal facility, Towanda PA. Source:

Photo 5.20 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 5.22 Construction of freshwater impoundment in Upshur Co. WV. Source: Chesapeake Energy

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, surrounding land use and proximity to nearby development, particularly residential development, 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 5.22 depicts a centralized freshwater impoundment and its construction.

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.[184] After the procedure is actually performed, the data gathered can be used to optimize future treatments.[185] Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging.[186,187] ICF International, under contract to NYSERDA to provide research assistance for this document, observed that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models.[188] Comparison of production pressure and flow-rate

[184] GWPC, April 2009, p. 57.

[185] GWPC, April 2009, p. 57.

[186] GWPC, April 2009, p. 57.

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

[188] ICF, 2009, p.6.

analysis to pre-fracture modeling is a more common method for evaluating the results of a hydraulic fracturing procedure.[189]

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.[190] Economics would also 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.[191] 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 production brine, or could result in loss of economic hydrocarbon production from the well.[192]

5.8.1 Fracture Development

ICF reviewed how hydraulic fracturing is affected by the rock's natural compressive stresses.[193] 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 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 nearly infinite in horizontal extent relative to their thickness, lateral expansion is constrained by the pressure of the horizontally adjacent rock mass.[194]

Rock stresses may decrease over geologic time as a result of erosion acting to decrease vertical rock thickness. Horizontal stress decreases due to erosion more slowly than vertical stress, so rock layers that are closer to the surface have a higher ratio of horizontal stress to vertical stress.[195]

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[189] ICF, 2009, pp. 6-8.

[190] GWPC, April 2009, p. 58.

[191] ICF, 2009, p. 14.

[192] GWPC, April 2009, p. 58.

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

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

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

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.[196]

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.[197] 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."[198]

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.[199] Pre-treatment modeling, as discussed above, is one tool for designing fracture treatments based on projected fracture behavior. Other control techniques identified by ICF include:[200]

- 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.

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196 ICF, 2009, pp. 14-15.

197 ICF, 2009, pp. 14-15.

198 ICF, 2009, pp. 14-15.

199 ICF, 2009, p. 16.

200 ICF, 2009, p. 17.

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. [201]

Photo 5.23 shows personnel monitoring a hydraulic fracturing procedure.

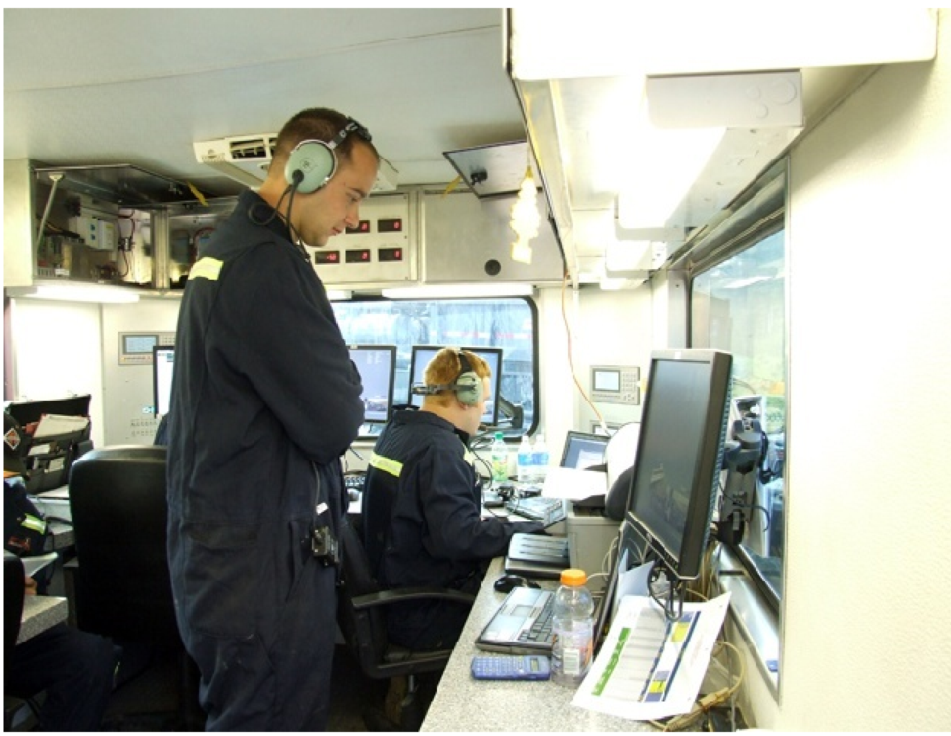

Photo 5.23 - Personnel monitoring a hydraulic fracturing procedure. Source: Fortuna Energy.

[201] ICF, 2009, p. 19.

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 (DMN) 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 have been removed. There will typically be at least three 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 intermediate casing string, also called protective string, is installed between the surface and production strings. 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 geologic conditions, there may be one or more intermediate casing strings. The inner production casing is the only casing string that will experience the high pressures associated with the fracturing treatment.[202] Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.

The last steps prior to fracturing are installation of a wellhead (referred to as a "frac tree") that is designed and pressure-rated specifically for the fracturing operation, and pressure testing of the

[202] 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.

hydraulic fracturing system. Photo 5.24 depicts a frac tree that is pressure-rated for 10,000 psi. Before perforating the casing and pumping fracturing fluid into the well, the operator pumps fresh water, brine or drilling mud to pressure test the production casing, frac tree and associated lines. 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, frac tree and associated lines will successfully hold pressure and contain the treatment. The test pressure may exceed the maximum anticipated treatment pressure, but must remain below the working pressure of the lowest rated component of the hydraulic fracturing system, including the production casing. Flowback equipment, including pipes, manifolds, a gas-water separator and tanks are connected to the frac tree and this portion of the flowback system is pressure tested prior to flowing the well.

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: New York State Department of Environmental Conservation 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,[203] 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.[204] 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 of water.[205] 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 (gpm).[206,207] 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 intermittent pumping during a 2- to 5-day period. Pumping rates may vary from job-to-job and some operators have reported pump rates in excess of 3,000 gpm and hydraulic fracturing at these higher rates could shorten the overall time spent pumping.

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203 GWPC, April 2009, p. 58.

204 GWPC, April 2009, p. 58.

205 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 (April 2009), pp. 58-59, where an example of a single-stage Marcellus fracturing 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.

206 ICF Task 1, 2009, p. 3.

207 GWPC, April 2009, p. 59.

The time spent pumping is the only time, except for when the well is shut-in, that wellbore pressure exceeds pressure in the surrounding formation. Therefore, the hours spent pumping are 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, assuming hypothetically that the entire bedrock column between the Marcellus and a fresh groundwater aquifer is hydraulically connected. 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.[208] More information about ICF's analysis is in Chapter 6 and in Appendix 11.

Within each fracturing stage is a series of sub-stages, or steps.[209, 210] 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 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.[211] The fractures are filled with fluid, and as the fracture width grows, more fluid must be pumped at the same or greater pressure exerted to maintain and propagate the fractures.[212] 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 in the hydraulic fracturing process is a freshwater or brine flush to clean out the

[208] ICF Task 1, 2009, pp. 27-28.

[209] URS, 2009, pp. 2-12.

[210] GWPC, April 2009, pp. 58-60.

[211] ICF Task 1, 2009. p. 16.

[212] ICF Task 1, 2009. p. 16.

wellbore and equipment. After hydraulic fracturing is complete, the stage plugs are removed through a milling process routinely accomplished by a relatively small workover rig, snubbing unit and/or coiled tubing unit. A snubbing unit or coiled tubing unit may be required if the well is not dead or if pressure is anticipated after milling through the plugs. Stage plugs may be removed before or after initial flowback depending upon the type of plug used.

Photo 5.25 and Photo 5.26 depict the same wellsite during and after hydraulic fracturing operations, with Photo 5.25 labeled to identify the equipment that is present onsite. Photo 5.27 is a labeled close-up of a wellhead and equipment at the site during hydraulic fracturing operations.

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.[213] 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.[214] 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.[215] 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.

[213] ICF Task 1, 2009, p. 18.

[214] ICF Task 1, 2009, p. 18.

[215] ICF Task 1, 2009, p. 17.


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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 5.27 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.

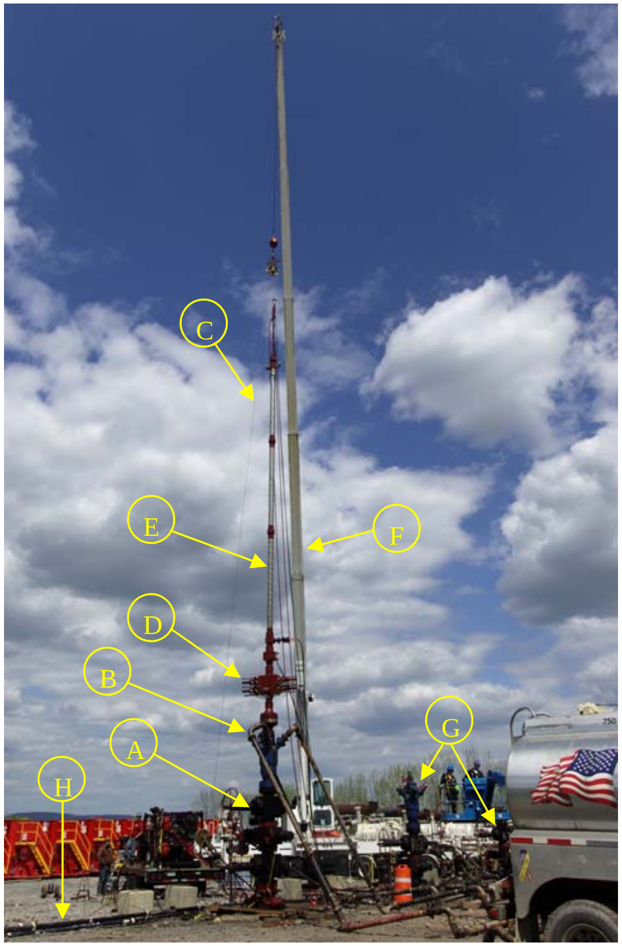

Photo 5.27. Wellhead and Frac Equipment
A. Well head and frac tree (valves)
B. Goat Head (for frac flow connections)
C. Wireline (used to convey equipment into wellbore)
D. Wireline Blow Out Preventer
E. Wireline lubricator
F. Crane to support wireline equipment
G. Additional wells
H. Flow line (for flowback & testing)

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.[216] Re-fracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.[217] Changes in formation stresses due to the 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. [218]

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.[219] 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.[220]

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

[216] ICF Task 1, 2009, p. 17.

[217] ICF Task 1, 2009, p. 17.

[218] ICF Task 1, 2009, pp. 17-18.

[219] ICF Task 1, 2009, p. 18.

[220] ICF Task 1, 2009, p. 18.

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 a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9. 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 reported that limited time-series data indicates that approximately 60 percent of the total flowback occurs in the first four days after fracturing.[221]

5.11.2 Flowback Water Handling at the Wellsite

As discussed throughout this document, the Department will require water-tight tanks for on-site (i.e., well pad) handling of flowback water for wells covered by the SGEIS.

5.11.3 Flowback Water Characteristics

The 1992 GEIS identified high 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).

The following description of flowback water characteristics was provided by URS Corporation,[222] 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

[221] URS, 2009, p. 3-2.

[222] URS, 2009, p. 3-2 & 2011, p. 3-2.

not direct or oversee 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 the Department, so little information is available to document whether and at what concentrations most fracturing chemicals occur in flowback water. 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 the Department 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).

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; and
- Acid gases (carbon dioxide, hydrogen sulfide).

A list of parameters detected in a limited set of analytical results is provided in Table 5.9. Typical concentrations of parameters other than radionuclides, based on limited data from Pennsylvania and West Virginia, are provided in Table 5.10 and Table 5.11. Flowback parameters were organized by CAS number, whenever available. Radionuclides are separately discussed and tabulated in Section 5.11.3.2.

Table 5.9 - Parameters present in a limited set of flowback analytical results[223] (Updated July 2011)

CAS Number	Parameters Detected in Flowback from PA and WV Operations
00087-61-6	1,2,3-Trichlorobenzene
00095-63-6	1,2,4-Trimethylbenzene
00108-67-8	1,3,5-Trimethylbenzene
00105-67-9	2,4-Dimethylphenol
00087-65-0	2,6-Dichlorophenol
00078-93-3	2-Butanone / Methyl ethyl ketone
00091-57-6	2-Methylnaphthalene
00095-48-7	2-Methylphenol
109-06-8	2-Picoline (2-methyl pyridine)
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol
00108-39-4	3-Methylphenol
00106-44-5	4-Methylphenol
00072-55-9	4,4 DDE
00057-97-6	7,12-Dimethylbenz(a)anthracene
00064-19-7	Acetic acid
00067-64-1	Acetone
00098-86-2	Acetophenone
00107-13-1	Acrylonitrile
00309-00-2	Aldrin
07439-90-5	Aluminum
07440-36-0	Antimony
07664-41-7	Aqueous ammonia
12672-29-6	Aroclor 1248
07440-38-2	Arsenic
07440-39-3	Barium
00071-43-2	Benzene

223 This table contains information compiled from flowback analyses submitted to the Department by well operators as well as flowback information from the Marcellus Shale Coalition Study.

CAS Number	Parameters Detected in Flowback from PA and WV Operations
00050-32-8	Benzo(a)pyrene
00205-99-2	Benzo(b)fluoranthene
191-24-2	Benzo(ghi)perylene
00207-08-9	Benzo(k)fluoranthene
00100-51-6	Benzyl alcohol
07440-41-7	Beryllium
00111-44-4	Bis(2-Chloroethyl) ether
00117-81-7	Bis(2-ethylhexyl)phthalate / Di (2-ethylhexyl) phthalate
07440-42-8	Boron
24959-67-9	Bromide
00075-25-2	Bromoform
07440-43-9	Cadmium
07440-70-2	Calcium
00124-38-9	Carbon Dioxide
00075-15-0	Carbondisulfide
00124-48-1	Chlorodibromomethane
00067-66-3	Chloroform
07440-47-3	Chromium
07440-48-4	Cobalt
07440-50-8	Copper
00057-12-5	Cyanide
00319-85-7	Cyclohexane (beta BHC)
00058-89-9	Cyclohexane (gamma BHC)
00055-70-3	Dibenz(a,h)anthracene
00075-27-4	Dichlorobromomethane
00084-74-2	Di-n-butyl phthalate
00122-39-4	Diphenylamine
00959-98-8	Endosulfan I
33213-65-9	Endosulfan II
07421-93-4	Endrin aldehyde
00107-21-1	Ethane-1,2-diol / Ethylene Glycol
00100-41-4	Ethyl Benzene
00206-44-0	Fluoranthene
00086-73-7	Fluorene
16984-48-8	Fluoride
00076-44-8	Heptachlor
01024-57-3	Heptachlor epoxide
00193-39-5	Indeno(1,2,3-cd)pyrene
07439-89-6	Iron
00098-82-8	Isopropylbenzene (cumene)
07439-92-1	Lead
07439-93-2	Lithium
07439-95-4	Magnesium

CAS Number	Parameters Detected in Flowback from PA and WV Operations
07439-96-5	Manganese
07439-97-6	Mercury
00067-56-1	Methanol
00074-83-9	Methyl Bromide
00074-87-3	Methyl Chloride
07439-98-7	Molybdenum
00091-20-3	Naphthalene
07440-02-0	Nickel
00086-30-6	N-Nitrosodiphenylamine
00085-01-8	Phenanthrene
00108-95-2	Phenol
57723-14-0	Phosphorus
07440-09-7	Potassium
00057-55-6	Propylene glycol
00110-86-1	Pyridine
00094-59-7	Safrole
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
07440-62-2	Vanadium
07440-66-6	Zinc
	2-Picoline
	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
	Cesium 137
	Chemical Oxygen Demand
	Chloride

CAS Number	Parameters Detected in Flowback from PA and WV Operations
	Chromium (VI)
	Chromium (VI), dissolved
	Chromium, (III)
	Chromium, Dissolved
	Cobalt, dissolved
	Coliform
	Color
	Conductivity
	Hardness
	Heterotrophic plate count
	Iron, Dissolved
	Lithium, Dissolved
	Magnesium, Dissolved
	Manganese, Dissolved
	Nickel, Dissolved
	Nitrate, as N
	Nitrogen, Total as N
	Oil and Grease
	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
	Volatile Acids
	Xylenes
	Zinc, Dissolved
	Zirconium

Parameters listed in Table 5.9, Table 5.10 and Table 5.11 are based on analytical results of flowback from operations in Pennsylvania or West Virginia. All information is for operations in the Marcellus Shale, however it is not from a single comprehensive study. The data are based on analyses performed by different laboratories; most operators provided only one sample/analysis per well, a few operators provided time-series samples for a single well; the different samples were analyzed for various parameters with some overlap of parameters. Even though the data are not strictly comparable, they provide valuable insight on the likely composition of flowback at New York operations.

Table 5.10 - Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[224,225] (Revised July 2011)

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Acidity, Total	4	4	101	240	874	mg/L
	Alkalinity [226]	155	155	0	153	384	mg/L
	Alkalinity, Carbonate, as $CaCO_3$	164	163	0	9485	48336	mg/L
	Total Alkalinity	5	5	28	91	94	mg/L
07439-90-5	Aluminum	43	12	0.02	0.07	1.2	mg/L
	Aluminum, Dissolved	22	1	1.37	1.37	1.37	mg/L
07440-36-0	Antimony	34	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	48	45	11.3	44.8	382	mg/L
07440-38-2	Arsenic	43	7	0.015	0.09	0.123	mg/L
07440-39-3	Barium	48	47	0.553	1450	15700	mg/L
	Barium, Dissolved	22	22	0.313	212	19200	mg/L
00071-43-2	Benzene	35	14	15.7	479.5	1950	µg/L
07440-41-7	Beryllium	43	1	422	422	422	mg/L

224 Table 5.9 was provided by URS Corporation (based on data submitted to the Department) 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. Additionally, it should be noted that several of these compounds could be traced back to potential laboratory contamination. Further comparisons of analytical results with those results from associated laboratory method blanks may be required to further assess the extent of actual concentrations found in field samples versus elevated concentrations found in field samples due to blank contamination.

225 This table does not include results from the Marcellus Shale Coalition Study.

226 Different data sources reported alkalinity in different and valid forms. Total alkalinity reported here is smaller than carbonate alkalinity because the data came from different sources.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	Bicarbonates	150	150	0	183	1708	mg/L
	Biochemical Oxygen Demand	38	37	3	200	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	20	2	10.3	15.9	21.5	µg/L
07440-42-8	Boron	23	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	15	15	11.3	607	3070	mg/L
00075-25-2	Bromoform	26	2	34.8	36.65	38.5	µg/L
07440-43-9	Cadmium	43	6	0.007	0.025	1.2	mg/L
	Cadmium, Dissolved	22	2	0.017	0.026	0.035	mg/L
07440-70-2	Calcium	187	186	29.9	4241	123000	mg/L
	Calcium, Dissolved	3	3	2360	22300	31500	mg/L
	Cesium 137 [227]	16	2	9.9	10.2	10.5	pCi/L
	Chemical Oxygen Demand	38	38	223	5645	33300	mg/L
	Chloride	193	193	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	26	2	3.28	3.67	4.06	µg/L
07440-47-3	Chromium	43	9	0.009	0.082	760	mg/L
	Chromium (VI), dissolved	19	10	0.0126	0.539	7.81	mg/L
	Chromium, Dissolved	22	2	0.058	0.075	0.092	mg/L
07440-48-4	Cobalt	30	6	0.03	0.3975	0.62	mg/L
	Cobalt, dissolved	19	1	0.489	0.489	0.489	mg/L
	Coliform, Total	5	2	1	42	83	Col/100mL
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	43	8	0.01	0.0245	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	38	14	3.3	53.6	164	µg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
	Heterotrophic plate count	5	3	25	50	565	CFU/mL
07439-89-6	Iron	193	168	0	29.2	810	mg/L
	Iron, Dissolved	34	26	6.75	63.25	196	mg/L
07439-92-1	Lead	43	6	0.008	0.035	27.4	mg/L
	Lithium	13	13	34.4	90.4	297	mg/L
	Lithium, Dissolved	4	4	24.5	61.35	144	mg/L
07439-95-4	Magnesium	193	180	9	177	3190	mg/L
	Magnesium, Dissolved	3	3	218	2170	3160	mg/L
	Mg as CaCO3	145	145	36	547	8208	mg/L
07439-96-5	Manganese	43	29	0.15	1.89	97.6	mg/L
	Manganese, Dissolved	22	12	0.401	2.975	18	mg/L
07439-97-6	Mercury	30	2	0.0006	0.295	0.59	mg/L
00074-83-9	Methyl Bromide	26	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	26	1	15.6	15.6	15.6	µg/L
07439-98-7	Molybdenum	34	12	0.16	0.44	1.08	mg/L
00091-20-3	Naphthalene	23	1	11.3	11.3	11.3	µg/L
07440-02-0	Nickel	43	15	0.01	0.03	0.137	mg/L
	Nickel, Dissolved	22	2	0.03	0.0715	0.113	mg/L
	Nitrate, as N	1	1	0.025	0.025	0.025	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	39	9	5	17	1470	mg/L
	Petroleum hydrocarbons	1	1	0.21	0.21	0.21	mg/L
	pH	191	191	0	6.6	8.58	S.U.
00108-95-2	Phenol	20	1	459	459	459	µg/L

[227] Regulated under beta particles [19].

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	Phenols	35	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	33	17	15.5	125	7810	mg/L
	Potassium, Dissolved	3	3	84.2	327	7080	mg/L
	Scale Inhibitor	145	145	315	744	1346	mg/L
07782-49-2	Selenium	34	1	0.058	0.058	0.058	mg/L
	Selenium, Dissolved	22	1	1.06	1.06	1.06	mg/L
07440-22-4	Silver	43	3	0.129	0.204	6.3	mg/L
	Silver, Dissolved	22	2	0.056	0.0825	0.109	mg/L
07440-23-5	Sodium	42	41	83.1	23500	96700	mg/L
	Sodium, Dissolved	3	3	9290	54800	77400	mg/L
07440-24-6	Strontium	36	36	0.501	1115	5841	mg/L
	Strontium, Dissolved	22	21	8.47	629	7290	mg/L
14808-79-8	Sulfate (as SO_4)	193	169	0	1	1270	mg/L
	Sulfide (as S)	8	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO_3)	3	3	2.56	64	64	mg/L
	Surfactants [228]	12	12	0.1	0.21	0.61	mg/L
00127-18-4	Tetrachloroethylene	26	1	5.01	5.01	5.01	µg/L
07440-28-0	Thallium	34	2	0.1	0.18	0.26	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	38	15	2.3	833	3190	µg/L
	Total Dissolved Solids	193	193	1530	63800	337000	mg/L
07440-62-2	Vanadium	24	1	40.4	40.4	40.4	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [229]	28	23	69.2	449	1080	mg/L
	Total Suspended Solids	43	43	16	129	2080	mg/L
	Xylenes	38	15	15.3	444	2670	µg/L
07440-66-6	Zinc	43	18	0.011	0.036	8570	mg/L
	Zinc, Dissolved	22	1	0.07	0.07	0.07	mg/L
	Fluid Density	145	145	8.39004	8.7	9.2	lb/gal
	Hardness by Calculation	170	170	203	11354	98000	mg $CaCO_3$/L
	Salt %	145	145	0.9	5.8	13.9	%
	Specific Conductivity	15	15	1030	110000	165000	pmhos/cm
	Specific Gravity	150	154	0	1.04	1.201	
	Temperature	31	31	0	15.3	32	°C
	Temperature	145	145	24.9	68	76.1	°F

[228] Regulated under foaming agents.
[229] Regulated via BOD, COD and the different classes/compounds of organic carbon.

Table 5.11 - Typical concentrations of flowback constituents based on limited samples from PA and WV, not regulated in NY[230] (Revised July 2011)

Parameter Name	Total Number of Samples	Detects	Min	Median	Max	Units
Barium Strontium P.S.	145	145	17	1320	6400	mg/L
Carbon Dioxide	5	5	193	232	294	mg/L
Zirconium	19	1	0.054	0.054	0.054	mg/L

Recognizing the dearth of comparable flowback information that existed at that time within the Marcellus Shale, the Marcellus Shale Coalition (MSC) facilitated a more rigorous study in 2009. The study:

- Gathered and analyzed flowback samples from 19 gas well sites (names A through S) in Pennsylvania or West Virginia;
- Took samples at different points in time, typically of the influent water stream, and flowback water streams 1, 5, 14, and 90 days after stimulating the well. In addition, the water supply and the fracturing fluid (referred to as Day 0) were also sampled at a few locations;
- Included both vertical and horizontal wells;
- All samples were collected by a single contractor;
- All analyses were performed by a single laboratory;
- Sought input from regulatory agencies in Pennsylvania and West Virginia; and
- Most samples were analyzed for conventional parameters, Metals, VOCs, Semi-Volatile Organic Compounds (SVOCs), Organochlorine Pesticides, Polychlorinated Biphenyls (PCBs), an Organophosphorus Pesticide, Alcohols, Glycols, and Acids. The specific parameters analyzed in the MSC report are listed by class as follows:
    - 29 conventional parameters (presented in Table 5.12);

[230] Table 5-10.

- 59 total or dissolved metals (presented in Table 5.13);
- 70 VOCs (presented in Table 5.14);
- 107 SVOCs (presented in Table 5.15);
- 20 Organochlorine Pesticides (presented in Table 5.16);
- 7 PCB Arochlors (presented in Table 5.17);
- 1 Organophosphorus Pesticide (presented in Table 5.18);
- 5 Alcohols (presented in Table 5.19);
- 2 Glycols (presented in Table 5.20); and
- 4 Acids (presented in Table 5.21).

Table 5.12 - Conventional Analytes In MSC Study (New July 2011)

Acidity	Nitrate as N	Total phosphorus
Amenable cyanide	Nitrate-nitrite	Total suspended solids
Ammonia nitrogen	Nitrite as N	Turbidity
Biochemical oxygen demand	Oil & grease (HEM)	Total cyanide
Bromide	Specific conductance	Total sulfide
Chemical oxygen demand (COD)	Sulfate	pH
Chloride	TOC	Total recoverable phenolics
Dissolved organic carbon	Total alkalinity	Sulfite
Fluoride	Total dissolved solids	MBAS (mol.wt 320)
Hardness, as $CaCO_3$	Total Kjeldahl nitrogen	

Table 5.13 - Total and Dissolved Metals Analyzed In MSC Study (New July 2011)

	Copper	Silver
Aluminum-dissolved	Copper-dissolved	Silver-dissolved
Antimony	Iron	Sodium
Antimony-dissolved	Iron-dissolved	Sodium-dissolved
Arsenic	Lead	Strontium
Arsenic-dissolved	Lead-dissolved	Strontium-dissolved
Barium	Lithium	Thallium
Barium-dissolved	Lithium-dissolved	Thallium-dissolved
Beryllium	Magnesium	Tin
Beryllium-dissolved	Magnesium-dissolved	Tin-dissolved
Boron	Manganese	Titanium
Boron-dissolved	Manganese-dissolved	Titanium-dissolved
Cadmium	Molybdenum	Trivalent chromium
Cadmium-dissolved	Molybdenum-dissolved	Zinc
Calcium	Nickel	Zinc-dissolved
Calcium-dissolved	Nickel-dissolved	Hexavalent chromium-dissolved
Chromium	Potassium	Hexavalent chromium
Chromium-dissolved	Potassium-dissolved	Mercury
Cobalt	Selenium	Mercury-dissolved
Cobalt-dissolved	Selenium-dissolved	

Table 5.14 - Volatile Organic Compounds Analyzed in MSC Study (New July 2011)

	2-Chloroethyl vinyl ether	Ethylbenzene
1,1,1-Trichloroethane	2-Hexanone	Isopropylbenzene
1,1,2,2-Tetrachloroethane	4-Chlorotoluene	Methyl tert-butyl ether (MTBE)
1,1,2-Trichloroethane	4-Methyl-2-pentanone (MIBK)	Methylene chloride
1,1-Dichloroethane	Acetone	Naphthalene
1,1-Dichloroethene	Acrolein	n-Butylbenzene
1,1-Dichloropropene	Acrylonitrile	n-Propylbenzene
1,2,3-Trichlorobenzene	Benzene	p-Isopropyltoluene
1,2,3-Trichloropropane	Benzyl chloride	sec-Butylbenzene
1,2,4-Trichlorobenzene	Bromobenzene	Styrene
1,2,4-Trimethylbenzene	Bromodichloromethane	tert-butyl acetate
1,2-Dibromo-3-chloropropane	Bromoform	tert-Butylbenzene
1,2-Dibromoethane (EDB)	Bromomethane	Tetrachloroethene
1,2-Dichlorobenzene	Carbon disulfide	tetrahydrofuran
1,2-Dichloroethane	Carbon tetrachloride	Toluene
1,2-Dichloropropane	Chlorobenzene	trans-1,2-Dichloroethene
1,3,5-Trimethylbenzene	Chloroethane	trans-1,3-Dichloropropene
1,3-Dichlorobenzene	Chloroform	Trichloroethene
1,3-Dichloropropane	Chloromethane	Trichlorofluoromethane
1,4-Dichlorobenzene	cis-1,2-Dichloroethene	Vinyl acetate
1,4-Dioxane	cis-1,3-Dichloropropene	Vinyl chloride
1-chloro-4-trifluoromethylbenzene	Dibromochloromethane	Xylenes (total)
2,2-Dichloropropane	Dibromomethane	
2-Butanone	Dichlorodifluoromethane	

Table 5.15 - Semi-Volatile Organics Analyzed in MSC Study (New July 2011)

1,2,4,5-Tetrachlorobenzene	7,12-Dimethylbenz(a)anthracene	Hexachlorocyclopentadiene
1,2-Diphenylhydrazine	Acenaphthene	Hexachloroethane
1,3-Dinitrobenzene	Acenaphthylene	Hexachloropropene
1,4-Naphthoquinone	Acetophenone	Indeno(1,2,3-cd)pyrene
1-Naphthylamine	Aniline	Isodrin
2,3,4,6-Tetrachlorophenol	Aramite	Isophorone
2,3,7,8-TCDD	Benzidine	Isosafrole
2,4,5-Trichlorophenol	Benzo(a)anthracene	Methyl methanesulfonate
2,4,6-Trichlorophenol	Benzo(a)pyrene	Nitrobenzene
2,4-Dimethylphenol	Benzo(b)fluoranthene	N-Nitrosodiethylamine
2,4-Dinitrophenol	Benzo(ghi)perylene	N-Nitrosodimethylamine
2,4-Dinitrotoluene	Benzo(k)fluoranthene	N-Nitrosodi-n-butylamine
2,6-Dichlorophenol	Benzyl alcohol	N-Nitrosodi-n-propylamine
2,6-Dinitrotoluene	bis(2-Chloroethoxy)methane	N-Nitrosodiphenylamine
2-Acetylaminofluorene	bis(2-Chloroethyl) ether	N-Nitrosomethylethylamine
2-Chloronaphthalene	bis(2-Chloroisopropyl) ether	N-Nitrosomorpholine
2-Chlorophenol	bis(2-Ethylhexyl) phthalate	N-Nitrosopiperidine
2-Methylnaphthalene	Butyl benzyl phthalate	N-Nitrosopyrrolidine
2-Methylphenol	Chlorobenzilate	O,O,O-Triethyl phosphorothioate
2-Naphthylamine	Chrysene	o-Toluidine
2-Nitroaniline	Diallate	Parathion
2-Nitrophenol	Dibenz(a,h)anthracene	p-Dimethylaminoazobenzene
2-Picoline	Dibenzofuran	Pentachlorobenzene
3,3'-Dichlorobenzidine	Diethyl phthalate	Pentachloroethane
3-Methylcholanthrene	Dimethoate	Pentachloronitrobenzene
3-Methylphenol & 4-Methylphenol	Dimethyl phthalate	Pentachlorophenol
3-Nitroaniline	Di-n-butyl phthalate	Phenanthrene
4,6-Dinitro-2-methylphenol	Di-n-octyl phthalate	Phenol
4-Aminobiphenyl	Dinoseb	Phorate
4-Bromophenyl phenyl ether	Diphenylamine	Pronamide
4-Chloro-3-methylphenol	Disulfoton	Pyrene
4-Chloroaniline	Ethyl methanesulfonate	Pyridine
4-Chlorophenyl phenyl ether	Fluoranthene	Safrole
4-Nitroaniline	Fluorene	Thionazin
4-Nitrophenol	Hexachlorobenzene	Tetraethyldithiopyrophosphate
5-Nitro-o-toluidine	Hexachlorobutadiene	

Table 5.16 - Organochlorine Pesticides Analyzed in MSC Study (New July 2011)

4,4'-DDD	delta-BHC	Endrin ketone
4,4'-DDE	Dieldrin	gamma-BHC (Lindane)
4,4'-DDT	Endosulfan I	Heptachlor
Aldrin	Endosulfan II	Heptachlor epoxide
alpha-BHC	Endosulfan sulfate	Methoxychlor
beta-BHC	Endrin	Toxaphene
Chlordane	Endrin aldehyde	

Table 5.17 - PCBs Analyzed in MSC Study (New July 2011)

Aroclor 1016	Aroclor 1242	Aroclor 1260
Aroclor 1221	Aroclor 1248	
Aroclor 1232	Aroclor 1254	

Table 5.18 - Organophosphorus Pesticides Analyzed in MSC Study (New July 2011)

Ethyl parathion

Table 5.19 - Alcohols Analyzed in MSC Study (New July 2011)

2-Propanol	Ethanol	n-Propanol
Butyl alcohol	Methanol	

Table 5.20 - Glycols Analyzed in MSC Study (New July 2011)

Ethylene glycol
Propylene glycol

Table 5.21 - Acids Analyzed in MSC Study (New July 2011)

Acetic acid	Propionic acid
Butyric acid	Volatile acids

Table 5.22 is a summary of parameter classes analyzed for (shown with a "•") at each well site. Table 5.23 is a summary of parameters detected at quantifiable levels. The check mark (√) indicates that several samples detected many parameters within a class. The MSC Study Report lists the following qualifiers associated with analytical results:

The sample was diluted (from 1X, which means no dilution, to up to 1000X) due to concentrations of analytes exceeding calibration ranges of the instrumentation or due to potential matrix effect. Laboratories use best judgment when analyzing samples at the lowest dilution factors allowable without causing potential damage to the instrumentation;

The analyte was detected in the associated lab method blank for the sample. Sample results would be flagged with a laboratory-generated single letter qualifier (i.e., "B");

The estimated concentration of the analyte was detected between the method detection limit and the reporting limit. Sample results would be flagged with a laboratory-generated single letter qualifier (i.e., "J"). These results should be considered as estimated concentrations; and

The observed value was less than the method detection limit. These results will be flagged with a "U."

Table 5.22 - Parameter Classes Analyzed for in the MSC Study (New July 2011)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Conventional Analyses	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Metals	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
VOCs	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
SVOC	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Organochlorine Pesticides	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
PCBs	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Organophosphorus Pesticides	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Alcohols	NA	•	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Glycols	NA	•	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Acids	NA	NA	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•

Table 5.23 - Parameter Classes Detected in Flowback Analyticals in MSC Study (New July 2011)

	# parameters analyzed for	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Conventional Analyses	29	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Metals	59	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
VOCs	70	7	6	1	2	2	6	1	5	2	2	3	7	2	1	2	7	1	5	5
SVOC	107	3	6	1	5	3	6	2	2	9	8	6	2	1	1	1	6	1	7	6
Organochlorine Pesticides	20	0	0	1	1	0	1	0	2	1	2	1	1	1	0	0	0	2	3	2
PCBs	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Organophosphorus Pesticides	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alcohols	5	0	1	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Glycols	2	0	1	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Acids	4	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1	1	1	2	2

Metals and conventional parameters were detected and quantified in many of the samples and these observations are consistent with parameters listed in Table 5.9. However, the frequency of occurrence of other parameter classes was much lower: Table 5.23 summarizes the number of VOCs, SVOCs, PCBs, Pesticides, Alcohols, Glycols, and Acids observed in samples taken from each well. For the purposes of Table 5.23, if a particular parameter was detected in any sample from a single well, whether detected in one or all five (Day 0, 1, 5, 14 or 90) samples, it was considered to be one parameter.

- Between 1 and 7 of the 70 VOCs were detected in samples from well sites A through S. VOCs detected include:

1,2,3-Trichlorobenzene	Benzene	Isopropylbenzene
1,2,4-Trimethylbenzene	Bromoform	Naphthalene
1,3,5-Trimethylbenzene	Carbondisulfide	Toluene
2-Butanone	Chloroform	Xylenes
Acetone	Chloromethane	
Acrylonitrile	Ethylbenzene	

- Between 1 and 9 of the 107 SVOCs were detected in samples from well sites A through S. SVOCs detected include:

2,4-Dimethylphenol	Benzo(b)fluoranthene	Fluoranthene
2,6-Dichlorophenol	Benzo(ghi)perylene	Fluorene
2-Methylnaphthalene	Benzo(k)fluoranthene	Indeno(1,2,3-cd)pyrene
2-Methylphenol	Benzyl alcohol	N-Nitrosodiphenylamine
2-Picoline	bis(2-Chloroethyl) ether	Phenanthrene
3-Methylphenol & 4-Methylphenol	bis(2-Ethylhexyl) phthalate	Phenol
7,12-Dimethylbenz(a)anthracene	Dibenz(a,h)anthracene	Pyridine
Acetophenone	Di-n-butyl phthalate	Safrole
Benzo(a)pyrene	Diphenylamine	

- At most, 3 of the 20 Organochlorine Pesticides were detected. Organochlorine Pesticides detected include:

4,4 DDE	cyclohexane (gamma BHC)	endrin aldehyde
Aldrin	endosulfan I	Heptachlor
cyclohexane (beta BHC)	endosulfan II	heptachlor epoxide

- Only 1 (Aroclor 1248) of the 7 PCBs was detected, and that was only from one well site;

- Only 1 Organophosphorus Pesticide was analyzed for, but it was not detected in any sample;

- Of the 5 Alcohols analyzed for, 2 were detected at one well site and 1 each was detected at two well sites. Alcohols that were detected include 2-propanol and methanol;

- Of the 2 Glycols (Ethylene glycol and Propylene glycol) analyzed for, 1 each was detected at three well sites; and

- Of the 4 Acids analyzed for, 1 or 2 Acids (Acetic acid and Volatile Acids) were detected at several well sites.

Some parameters found in analytical results may be due to additives or supply water used in fracturing or drilling; some may be due to reactions between different additives; while others may have been mobilized from within the formation; still other parameters may have been contributed from multiple sources. Some of the volatile and semi-volatile analytical results may be traced back to potential laboratory contamination due to improper ventilation; due to chromatography column breakdown; or due to chemical breakdown of compounds during injection onto the instrumentation. Further study would be required to identify the specific origin of each parameter.

Nine pesticides and one PCB were identified by the MSC Study that were not identified by the flowback analytical results previously received from industry; all other parameters identified in the MSC study were already identified in the additives and/or flowback information received from industry.

Pesticides and PCBs do not originate within the shale play. If pesticides or PCBs were present in limited flowback samples in Pennsylvania or West Virginia, pesticides or PCBs would likely have been introduced to the shale or water during drilling or fracturing operations. Whether the pesticides or PCBs were introduced via additives or source water could not be evaluated with available information.

5.11.3.1 Temporal Trends in Flowback Water Composition

The composition of flowback water changes with time over the course of the flowback process, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water, including data from the MSC Study Report, indicate that:

- The concentrations of total dissolved solids (TDS), chloride, and barium increase;
- The levels of radioactivity increase,[231] and sometimes exceed MCLs;
- 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

[231] 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.

- Concentrations of metals increase.[232]

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.

5.11.3.2 NORM in Flowback Water

Several radiological parameters were detected in flowback samples, as shown in Table 5.24.

Table 5.24 - Concentrations of NORM constituents based on limited samples from PA and WV (Revised July 2011)

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
--	Gross Alpha	15	15	22.41	--	18,950	pCi/L
--	Gross Beta	15	15	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 re-use of flowback water for subsequent fracturing operations at the same well pad or other well pads; this practice is increasing and continuing to evolve in the Marcellus Shale.[233] Reuse involves either straight dilution of the flowback water with fresh water or the introduction on-site of more sophisticated treatment options prior to flowback reuse. Originally operators focused on treating flowback water using polymers and flocculants to precipitate out and remove metals, but more recently operators have begun using filtration technologies to achieve the same goal.[234] As stated above,

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[232] 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.

[233] ALL Consulting, 2010, p. 73.

[234] ALL Consulting, 2010, p. 73.

various on-site treatment technologies may be employed prior to reuse of flowback water. Regardless of the treatment objective, whether for reuse or direct discharge, the three basic issues that need consideration when developing water treatment technologies are:[235]

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); and
3. Disposal of residuals.

Untreated flowback water composition is discussed in Section 5.11.3. Table 5.25 summarizes allowable concentrations after treatment (and prior to potential additional dilution with fresh water).[236]

Table 5.25 - Maximum allowable water quality requirements for fracturing fluids, based on input from one expert panel on Barnett Shale (Revised July 2011)

Constituent	Concentration
Chlorides	3,000 - 90,000 mg/L
Calcium	350 - 1,000 mg/L
Suspended Solids	< 50 mg/L
Entrained oil and soluble organics	< 25 mg/L
Bacteria	< 100 cells/100 ml
Barium	Low levels

The following factors influence the decision to utilize on-site treatment and the selection of specific treatment options:[237]

Operational

- Flowback fluid characteristics, including scaling and fouling tendencies;
- On-site space availability;

[235] URS, 2009, p. 5-2.

[236] URS, 2009, p. 5-3.

[237] URS, 2009, p. 5-3.

- Processing capacity needed;
- Solids concentration in flowback fluid, and solids reduction required;
- Concentrations of hydrocarbons in flowback fluid, and targeted reduction in hydrocarbons;[238]
- Species and levels of radioactivity in flowback;
- Access to freshwater sources;
- Targeted recovery rate;
- Impact of treated water on efficacy of additives; and
- Availability of residuals disposal options.

Cost

- Capital costs associated with treatment system;
- Transportation costs associated with freshwater; and
- 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; and
- Regulatory environment.

5.12.1 Physical and Chemical Separation[239]

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[240]

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

[239] URS, 2009, p. 5-6.

and suspended matter from flowback. Modular physical and chemical separation units have been used in the Barnett Shale and Powder River Basin plays.

Physical separation technologies include hydrocyclones, filters, and centrifuges; however, filtration appears to be the preferred physical separation technology. The efficiency of filtration technologies is controlled by the size and quantity of constituents within the flowback fluid as well as the pore size and total contact area of the membrane. To increase filtration efficiency, one vendor provides a vibrating filtration unit (several different pore sizes are available) for approximately $300,000; this unit can filter 25,000 gpd.

Microfiltration has been shown to be effective in lab-scale research, nanofiltration has been used to treat production brine from off-shore oil rigs, and modular filtration units have been used in the Barnett Shale and Powder River Basin.[241] Nanofiltration has also been used in Marcellus development in Pennsylvania, though early experience there indicates that the fouling of filter packs has been a limiting constraint on its use.[242]

Chemical separation utilizes coagulants and flocculants to break emulsions (dissolved oil) and to remove suspended particles. The companion process of precipitation is accomplished by manipulating flowback chemistry such that constituents within the flowback (in particular, metals) will precipitate out of solution. This can also be performed sequentially, so that several chemicals will precipitate, resulting in cleaner flowback.

Separation and precipitation are used as pre-treatment steps within multi-step on-site treatment processes. Chemical separation units have been used in the Barnett Shale and Powder River Basin plays, and some vendors have proprietary designs for sequential precipitation of metals for potential use in the Marcellus Shale play.[243]

If flowback is to be treated solely for blending and re-use as fracturing fluid, chemical precipitation may be one of the only steps needed. By precipitation of scale-forming metals

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[240] Oil and grease are not expected in the Marcellus.

[241] URS 2011, p 5-6.

[242] Yoxtheimer, 2011 (personal communication).

[243] URS 2011, p 5-7.

(e.g., barium, strontium, calcium, magnesium), minimal excess treatment may be required. Prices for chemical precipitation systems are dependent upon the cost of the treatment chemicals; one vendor quoted a 15 gpm system for $450,000 or a 500 gpm system for approximately $1 million, with costs ranging from $0.50 to $3.00 per barrel.

5.12.2 Dilution

The dilution option involves blending flowback water with freshwater to make it usable for future fracturing operations. Because high concentrations of different parameters in flowback water may adversely affect the desired fracturing fluid properties, 100% recycling is not always possible without employing some form of treatment.[244,245] Concentrations of chlorides, calcium, magnesium, barium, carbonates, sulfates, solids and microbes in flowback water may be too high to use as-is, meaning that some form of physical and/or chemical separation is typically needed prior to recycling flowback.[246] In addition, the practice of blending flowback with freshwater involves balancing the additional freshwater water needs with the additional additive needs.[247] For example, 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. These considerations do not constrain reuse because both the dilution ratio and the additive concentrations can be adjusted to achieve the desired properties of the fracturing fluid.[248] In addition, service companies and chemical suppliers may develop additive products that are more compatible with the aforementioned flowback water parameters.

5.12.2.1 Reuse

The SRBC's reporting system for water usage within the Susquehanna River Basin (SRB) has provided a partial snapshot of flowback water reuse specific to Marcellus development. For the period June 1, 2008 to June 1, 2011, operators in the SRB in Pennsylvania reused approximately 311 million gallons of the approximately 2.14 billion gallons withdrawn and delivered to

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[244] URS, 2009, p. 5-1.

[245] ALL Consulting, 2010, p. 73.

[246] URS, 2009, p. 5-2.

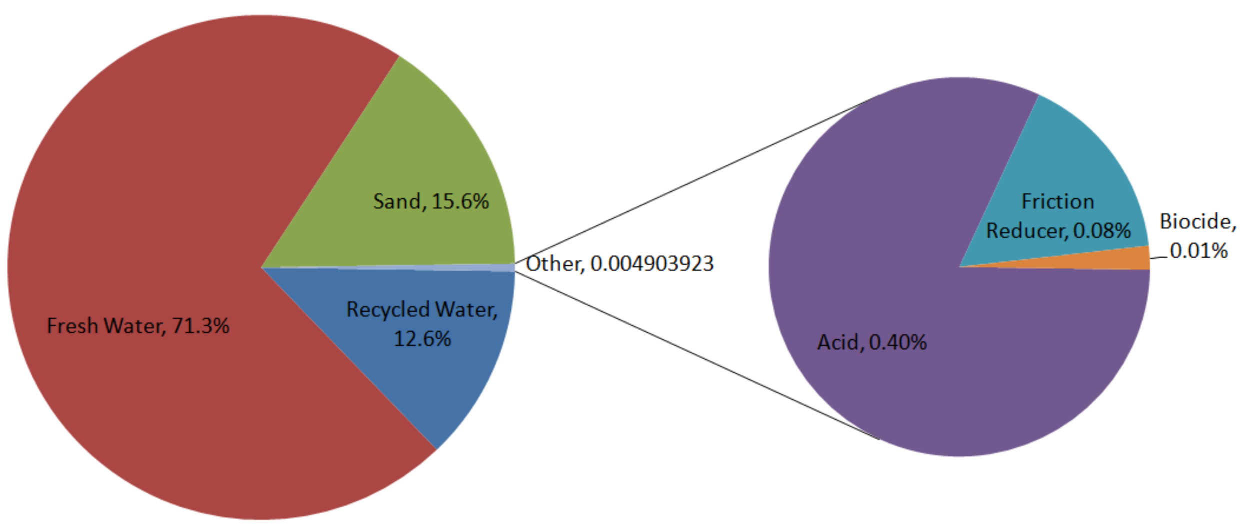
[247] URS, 2009, p. 5-2.

[248] ALL Consulting, 2010, p. 74.

Marcellus well pads. The SRBC data indicate that an average of 4.27 million gallons of water were used per well; this figure reflects an average of 3.84 million gallons of fresh water and 0.43 million gallons of reused flowback water per well.[249] The current limiting factors on flowback water reuse are the volume of flowback water recovered and the timing of upcoming fracture treatments.[250] Treatment and reuse of flowback water on the same well pad reduces the number of truck trips needed to haul flowback water to another destination.

Operators may propose to store flowback water prior to or after dilution in on-site tanks, which are discussed in Section 5.11.2. The tanks may be set up to segregate flowback based on estimated water quality. Water that is suitable for reuse with little or no treatment can be stored separately from water that requires some degree of treatment, and any water deemed unsuitable for reuse can then be separated for appropriate disposal.[251] An example of the composition of a fracturing solution that includes recycled flowback water is shown in Figure 5.6.

Figure 5.6 - Example Fracturing Fluid Composition Including Recycled Flowback Water (New July 2011)



[249] SRBC, 2011.

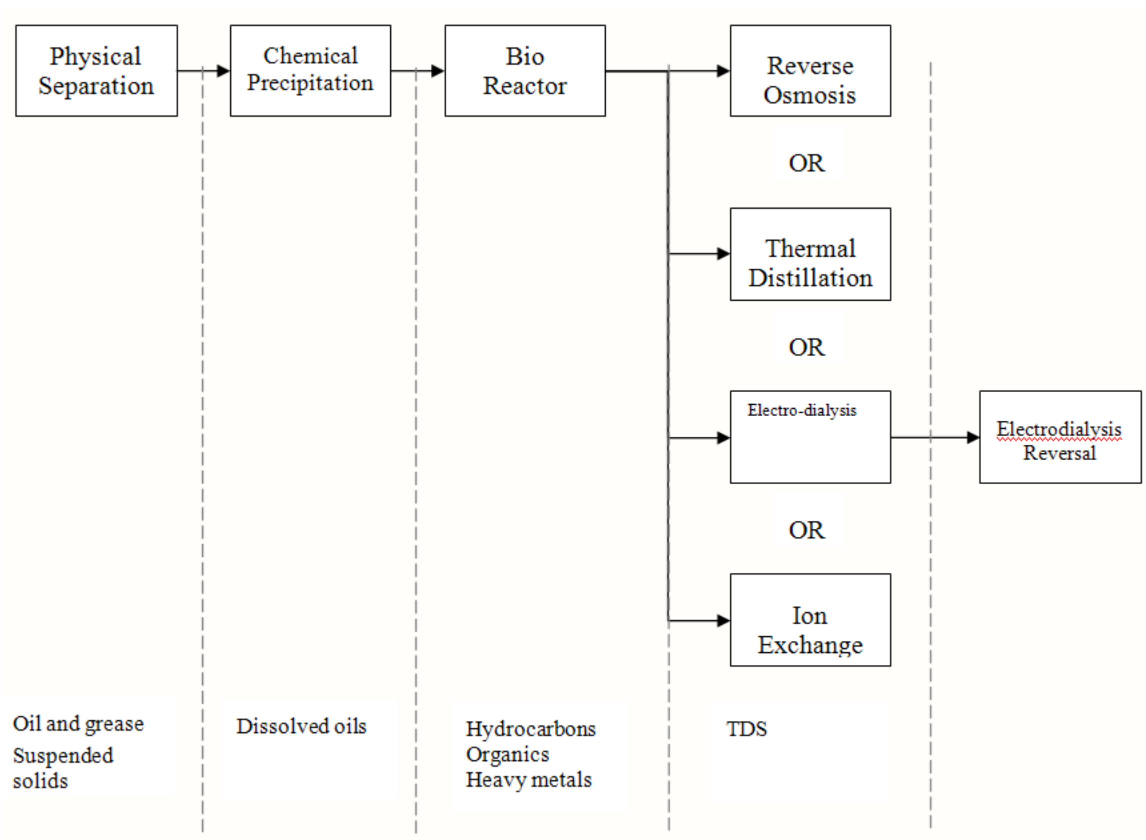
[250] ALL Consulting, 2010, p. 74.

[251] ALL Consulting, 2010, p. 74.

5.12.3 Other On-Site Treatment Technologies[252]

One example of an on-site treatment technology configuration is illustrated in Figure 5.7. The parameters treated are listed at the bottom of the figure. The next few sections present several on-site treatment technologies that have been used to some extent in other U.S. gas-shale plays.

Figure 5.7 - One configuration of potential on-site treatment technologies.



5.12.3.1 Membranes / Reverse Osmosis

Membranes are an advanced form of filtration, and may be used to treat TDS in flowback. The technology allows water - the permeate - to pass through the membrane, 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 45,000 mg/L, and produce an effluent with TDS concentrations between 200 and 500 mg/L. This technology generates a

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[252] URS, 2009, p. 5-4.

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; therefore, flowback water would likely require extensive pre-treatment 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, producing a concentrated brine effluent that will require further treatment and disposal. Reverse osmosis is a well-proven technology and is frequently used in desalination projects, in both modular and permanent configurations, though it is less efficient under high TDS concentrations. High TDS concentrations, such as in Marcellus flowback, [253] will likely result in large quantities of concentrated brine (also referred to as "reject") that will require further treatment or disposal. When designing treatment processes, several vendors use RO as a primary treatment (with appropriate pre-treatment prior to RO); and then use a secondary treatment method for the concentrated brine. The secondary treatment can be completed on-site, or the concentrated brine can be trucked to a centralized brine treatment facility.

Modular membrane technology units have been used in different regions for many different projects, including the Barnett Shale. Some firms have developed modular RO treatment units, which could potentially be used in the Marcellus.[254]

5.12.3.2 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, and have begun to be

[253] URS, 2011, p. 4-37.

[254] URS, 2011, p. 5-7.

used in the Marcellus Shale in Pennsylvania. In addition to the units that are already in use, several vendors have designs ready for testing, potentially further decreasing costs in the near future.[255]

5.12.3.3 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.

5.12.3.4 Electrodialysis/Electrodialysis Reversal

These treatment units are configured with alternating stacks of cation and anion membranes that allow passage of flowback fluid. 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. Modular electrodialysis units have been used in the Barnett Shale and Powder River Basin plays. Table 5.26 compares EDR and RO by outlining key characteristics of both technologies.

[255] URS, 2011 p. 5-8.

Table 5.26 - 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

5.12.3.5 Ozone/Ultrasonic/Ultraviolet

These technologies are designed to oxidize and separate hydrocarbons and heavy metals, and to oxidize biological films and bacteria from flowback water. The microscopic air bubbles in supersaturated ozonated water and/or ultrasonic transducers cause oils and suspended solids to float. Some vendors have field-tested the companion process of hydrodynamic cavitation, in which microscopic ozone bubbles implode, resulting in very high temperatures and pressures at the liquid-gas interface, converting the ozone to hydroxyl radicals and oxygen gas. The high temperatures and the newly-formed hydroxyl radicals quickly oxidize organic compounds.[256] Hydrodynamic cavitation has been used in field tests in the Fayetteville and Woodford Shale plays, but its use has not gained traction in the Marcellus play.[257]

Some vendors include ozone treatment technologies as one step in their flowback treatment process, including treatment for blending and re-use of water in drilling new wells. Systems incorporating ozone technology have been successfully used and analyzed in the Barnett Shale.[258]

[256] NETL, 2010.

[257] Yoxtheimer, 2011.

[258] URS, 2011 p. 5-9.

5.12.3.6 Crystallization/Zero Liquid Discharge

Zero liquid discharge (ZLD) follows the same principles as physical and chemical separation (precipitation, centrifuges, etc.) and evaporation, however a ZLD process ensures that all liquid effluent is of reusable or dischargeable quality. Additionally, any concentrate from the treatment process will be crystallized and will either be used in some capacity on site, will be offered for sale as a secondary product, or will be treated in such a way that it will meet regulations for disposal within a landfill. ZLD treatment is a relatively rare, expensive treatment process, and while some vendors suggest that the unit can be setup on the well pad, a more cost-effective use of ZLD treatment will be at a centralized treatment plant located near users of the systems' byproducts. In addition to the crystallized salts produced by ZLD, treated effluent water and/or steam will also be a product that can be used by a third party in some industrial or agricultural setting.

ZLD treatment systems are in use in a variety of industries, but none have been implemented in a natural gas production setting yet. Numerous technology vendors have advertised ZLD as a treatment option in the Marcellus, but the economical feasibility of such a system has not yet been demonstrated.[259]

5.12.4 Comparison of Potential On-Site Treatment Technologies

A comparison of performance characteristics associated with on-site treatment technologies is provided in Table 5.27[260]

[259] URS, 2011 p. 5-9.

[260] URS, 2009, p. 5-8.

Table 5.27 - Summary of Characteristics of On-Site Flowback Water Treatment Technologies (Updated July 2011)[261]

Characteristic	Filtration	Ion Exchange	Reverse Osmosis	EDR	Thermal Distillation	Ozone / Ultrasonic / Ultraviolet
Energy Cost	Low	Low	Moderate	High	High	Low
Energy Usage vs. TDS	N/A	Low	Increase	High Increase	Independent	Increase
Applicable to	All Water types	All Water types	Moderate TDS	High TDS	High TDS	All Water types
Plant / Unit size	Small / Modular	Small / Modular	Modular	Modular	Large	Small / Modular
Microbiological Fouling	Possible	Possible	Possible	Low	N/A	Possible
Complexity of Technology	Low	Low	Moderate / High Maintenance	Regular Maintenance	Complex	Low
Scaling Potential	Low	Low	High	Low	Low	Low
Theoretical TDS Feed Limit (mg/L)	N/A	N/A	32,000	40,000	100,000+	Depends on turbidity
Pretreatment Requirement	N/A	Filtration	Extensive	Filtration	Minimal	Filtration
Final Water TDS	No impact	200-500 ppm	200-500 ppm	200-1000 ppm	< 10 mg/L	Variable
Recovery Rate (Feed TDS >20,000 mg/L)	N/A	N/A	30-50%	60-80%	75-85%	Variable

5.13 Waste Disposal

5.13.1 Cuttings from Mud Drilling

The 1992 GEIS discusses on-site burial of cuttings generated during compressed 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 are considered industrial non-hazardous waste and therefore must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill. In New York State the NORM in cuttings is not precluded by regulation from disposal in a solid waste

[261] URS, 2011, p. 5-9

landfill, though well operators should consult with the operators of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility.

5.13.2 Reserve Pit Liner from Mud Drilling

The 1992 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 (SPDES). The program controls point source discharges to ground waters and surface waters. SPDES permits are issued to wastewater dischargers, including POTWs, 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 1992 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 (POTWs); and
- out-of-state industrial treatment plants.

Road spreading for dust control and de-icing (by a Part 364 Transporter with local government approval) is also discussed in the 1992 GEIS as a general disposition method used in New York for well-related fluids, primarily production brine (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 and a more detailed discussion of the potential environmental impacts and how they are mitigated is presented in Chapters 6 and 7.

5.13.3.1 Injection Wells

Discussed in Chapter 15 of the 1992 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, the use of these wells has been categorized and regulated as industrial discharge. The primary objective of both programs is protection of underground sources of drinking water, and neither the EPA nor the Department 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 SEIS addressing technical issues. An additional site-specific environmental assessment and SEQRA 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 DMN 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.

5.13.3.2 Municipal Sewage Treatment Facilities

Municipal sewage treatment facilities (also called POTWs) are regulated by the Department's DOW. POTWs typically discharge treated wastewater to surface water bodies, and operate under SPDES permits which include specific discharge limitations and monitoring requirements. In general, POTWs must have a Department-approved pretreatment program for accepting any industrial waste. POTWs must also notify the Department 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, the Department 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.

5.13.3.3 Out-of-State Treatment Plants

The only regulatory role the Department has over disposal of flowback water (or production brine) 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 5.28 lists out-of-state plants that were proposed in actual well permit applications for disposition of flowback water recovered in New York. The regulatory regimes in other states for treatment of this waste stream are evolving, and it is unknown whether disposal at the listed plants remains feasible.

Table 5.28 - 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

5.13.3.4 Road Spreading

Consistent with past practice regarding flowback water disposal, in January 2009, the Department's Division of Solid and Hazardous Materials (DSHM), which was then 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 from any formation including the Marcellus 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 DMN. This notification also addressed production brine and is included as Appendix 12. (Because of organizational changes within the Department since 2009, the Part 364 program is now overseen by the Division of Environmental Remediation (DER). As discussed in Chapter 7, BUDs for reuse of production brine from Marcellus Shale will not be issued until additional data on NORM content is available and evaluated.)

5.13.3.5 Private In-State Industrial Treatment Plants

Industrial facilities could be constructed or converted in New York to treat flowback water (and production brine). 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.

5.13.3.6 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.[262] 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 Materials Management (DMM). 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

[262] URS, 2009, p. 5-3.

testing that require flaring could last for 3 days per well.[263] Under the SGEIS, permit conditions would prohibit flaring during completion operations if a gathering line is in place.

5.15 Summary of Operations Prior to Production

Table 5.29 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 5.29, 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.

Table 5.29 - Primary Pre-Production Well Pad Operations (Revised July 2011)

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[264]

[263] ALL Consulting, 2010, pp. 10-11.

[264] 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 would be brought from off-site and is proportional to the distance which the rig would be moved. This time frame would 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
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 including possible changeover to workover rig to clean out well and run tubing-conveyed perforating equipment. Wireline truck on site to run cement bond log (CBL). 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. Truck trips to remove temporary water storage tanks.	Up to 6 weeks per well pad
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 average 1.5 acres in size during the long-term 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 5.30.

Table 5.30 - 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
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.[265] 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 5.30 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 reported in 2009 that no hydrogen sulfide had been detected at any of its active interconnects in Pennsylvania. Also in 2009, Fortuna Energy (now Talisman Energy) reported testing for hydrogen sulfide regularly with readings of 2 to 4 ppm during a brief period on one occasion in its vertical Marcellus wells, and that its presence had not recurred since. More recently, it has been reported to the Department that, beyond minor detections with mudlogging equipment, there is no substantiated occurrence of H_2S in Marcellus wells in the northern tier of Pennsylvania.[266]

5.16.3 Production Rate

Long-term 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/d or 10 MMcf/d, whichever is appropriate. IOGA-NY provided production estimates based on current information regarding production experience in Pennsylvania, but also noted the following caveats:

- The production estimates are based on 640-acre pad development with horizontal wells in the Marcellus fairway. Vertical wells and off-fairway development will vary.

[265] ICF Task 2, 2009, pp. 29-30.

[266] ALL Consulting, 2010, p. 49.

- The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania.

The per-well production estimates provided by IOGA-NY are as follows:

High Estimate

- Year 1 – initial rate of 8.72 MMcf/d declining to 3.49 MMcf/d.
- Years 2 to 4 – 3.49 MMcf/d declining to 1.25 MMcf/d.
- Years 5 to 10 – 1.25 MMcf/d declining to 0.55 MMcf/d.
- Years 11 and after – 0.55 MMcf/d declining at 5% per annum.
- The associated estimated ultimate recovery (EUR) is approximately 9.86 Bcf.

Low Estimate

- Year 1 – initial rate of 3.26 MMcf/d declining to 1.14 MMcf/d.
- Years 2 to 4 – 1.14 MMcf/d declining to 0.49 MMcf/d.
- Years 5 to 10 – 0.49 MMcf/d declining to 0.29 MMcf/d.
- Years 11 and after – 0.29 MMcf/d declining at 5% per annum.
- The associated EUR is approximately 2.28 Bcf.[267]

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).

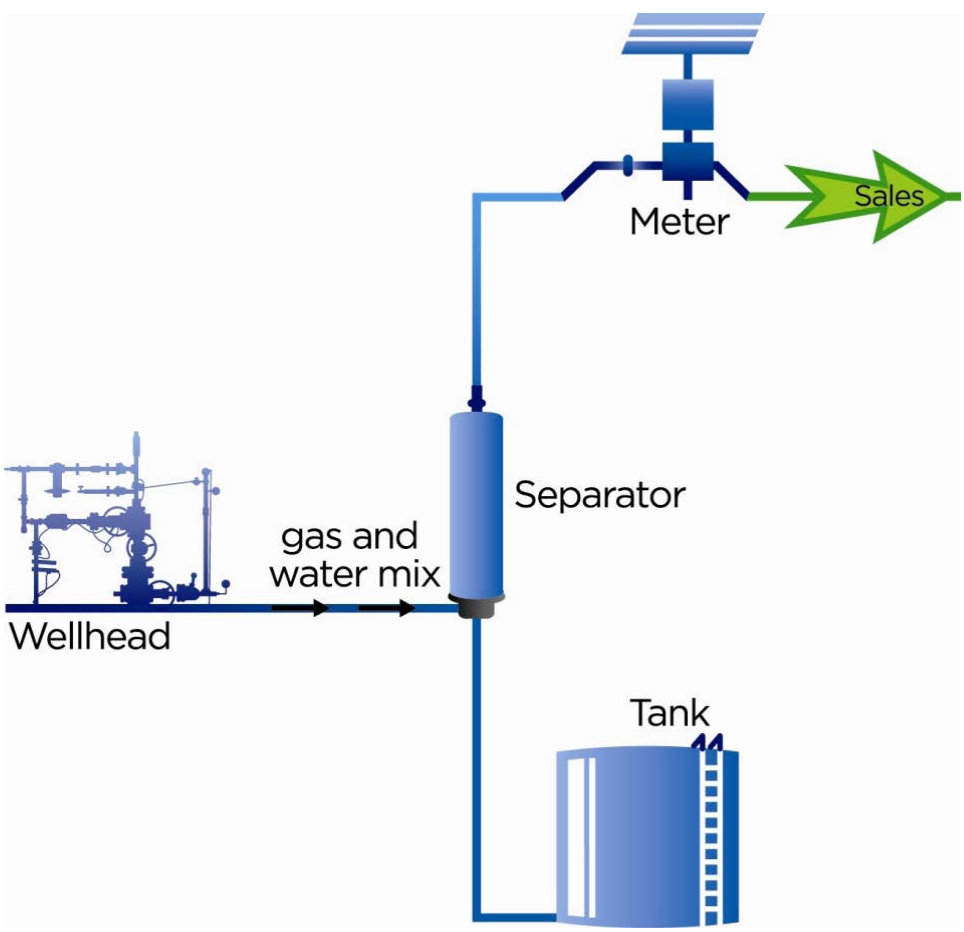
[267] ALL Consulting, 2011, p. 2.

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 5.8).

Figure 5.8 – 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 MMcf 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 discussed in the 1992 GEIS include injection wells, treatment plants and road spreading for dust control and de-icing, which are all discussed in the GEIS. If production brine is trucked off-site, it must be hauled by approved Part 364 Waste Transporters.

With respect to road spreading, in January 2009 the Department released a notification to haulers applying for, modifying, or renewing their Part 364 Waste Transporter Permits that any entity applying for a Part 364 permit or permit modification to use production brine 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. As discussed in Chapter 7, BUDs for reuse of production brine from Marcellus Shale will not be issued until additional data on NORM content is available and evaluated.

5.16.7 NORM 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. The NYSDOH will require the well operator to obtain a radioactive materials license for the facility when exposure rate measurements associated with scale accumulation in or on piping, drilling and brine storage equipment exceed 50 microR/hr (μR/hr). A license may be required for facilities that will concentrate NORM during pre-treatment or treatment of brine. 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 true vertical depth of the well times the pressure gradient. Therefore, the bottom-hole pressure on a 6,000-foot deep well will be approximately 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 polyvinyl chloride (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 description in Section 8.1.2.1 of the PSC's environmental review process, is 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. Environmental factors associated with gas-gathering and pipeline systems will be considered as part of the PSC's permitting process.

Photo 5.28 shows an aerial view of a compression facility.

Photo 5.28 - Pipeline Compressor in New York. Source: Fortuna Energy

5.17 Well Plugging

As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the 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 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review.

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Chapter 6

Potential Environmental Impact

Final

Supplemental Generic Environmental Impact Statement

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Chapter 6 – Potential Environmental Impacts

FIGURES

TABLES

PHOTOS

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Chapter 6 POTENTIAL ENVIRONMENTAL IMPACTS

This revised Draft SGEIS incorporates by reference the 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 information relating to potential impacts of horizontal drilling and high-volume hydraulic fracturing.

6.1 Water Resources

Protection of water resources is a primary emphasis of the Department. Water resource matters that may be impacted by activities associated with high-volume hydraulic fracturing are identified and discussed in Chapter 2.

Adverse impacts to water resources might reasonably be anticipated in the context of unmitigated high-volume hydraulic fracturing due to: 1) water withdrawals affecting surface or groundwater, including wetlands; 2) polluted stormwater runoff; 3) surface chemical or petroleum spills; 4) pit or surface impoundment failures or leaks; 5) groundwater contamination associated with improper well drilling and construction; and 6) improper waste disposal. NYC's subsurface water supply infrastructure that is located in areas outside the boundary of the NYC Watershed could also be impacted by unmitigated high-volume hydraulic fracturing. Potential surface water impacts discussed herein are applicable to all areas that might be developed for natural gas resources through high-volume hydraulic fracturing.

Three water resources issues were the subject of extensive comment during the public scoping process:

1) Potential degradation of NYC's surface drinking water supply;
2) Potential groundwater contamination from the hydraulic fracturing procedure itself; and
3) Adverse impacts to the Upper Delaware Scenic and Recreational River.

Geological factors as well as standard permit requirements that the Department proposes to impose that would limit or avoid the potential for groundwater contamination from high-volume hydraulic fracturing are discussed in Chapters 5, 7 and 8.

6.1.1 Water Withdrawals

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies or new or existing water-supply wells drilled into aquifers. Without proper controls on the rate, timing and location of such withdrawals, modifications to groundwater levels, surface water levels, and stream flow could result in adverse impacts to aquatic ecosystems, downstream flow levels, drinking water assured yields, wetlands, and aquifer recharge. While surface-water bodies are still the primary source of water supplies for the drilling of Marcellus wells in Pennsylvania, municipal and public water-supply wells have been used there as well.

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.

Unmitigated withdrawals could adversely impact fish and wildlife health due to exposure to unsuitable water temperature and dissolved oxygen concentrations, particularly in low-flow or drought conditions. It could also affect downstream dischargers whose effluent limits are linked to the stream's flow rate. Water quality could be degraded and adverse impacts on natural aquatic habitat increased if existing pollutants from point sources (e.g., discharge pipes) and/or non-point sources (e.g., runoff from farms and paved surfaces) become concentrated.

6.1.1.2 Degradation of a Stream's Best Use

New York State water use classifications are provided in Section 2.3.1. All of the uses are dependent upon sufficient water in the stream to support the specified use. As noted, uncontrolled withdrawals of water from streams in connection with high-volume hydraulic fracturing has the potential to adversely impact stream water supply and thus stream water use classifications.

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, in-stream 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. Stream fish distribution, community structure, and population dynamics are related to channel morphology. Streamflow alterations that modify channel morphology and habitat would result in changes in aquatic populations and community shifts that alter natural ecosystems. 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 would continuously provide suitable habitat for all aquatic biota. Clearly, alteration of flow regimes, sediment loads and riparian vegetation would cause changes in the morphology of stream channels. Any streamflow management decision would 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 stream habitat; or
- the actual water withdrawal infrastructure.

Native aquatic species possess life history traits that enable individuals to survive and reproduce within a certain range of environmental variation. Flow depth and velocity, water temperature, substrate size distribution and oxygen content are among the myriad of environmental attributes known to shape the habitat that control aquatic and riparian species distributions. Streamflow alterations can impact aquatic ecosystems due to community shifts made in response to the corresponding shifts in these environmental attributes. The perpetuation of native aquatic biodiversity and ecosystem integrity depends on maintaining some semblance of natural flow patterns that minimize aquatic community shifts. The natural flow paradigm states that the full range of natural intra- and inter-annual variation of hydrologic regimes, and associated characteristics of timing, duration, frequency and rate of change, are critical in sustaining the full native biodiversity and integrity of aquatic ecosystems.

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. While most of the water bodies supplying water for high-volume hydraulic fracturing contain species of fish whose early life stages are not likely to be entrained because of their life history and behavioral characteristics, fish in their older life stages could be entrained without measures to avoid or reduce adverse impacts. 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. Depending on the water body from which water is being withdrawn, the location of the withdrawal structure on the water body and the site-specific aquatic organisms requiring protection, project-specific technologies may be required to minimize the entrainment and impingement of aquatic organisms. Technologies and operational measures that are proven effective in reducing these impacts include but are not limited to narrow-slot width wedge-wire screens (0.5 mm-2.0 mm), fine mesh screening, low intake velocities (0.5 feet per second (fps) or less), and seasonal restrictions on intake operation. Transporting water from the water withdrawal location for use off-site, as discussed in Section 6.4.2.2, can transfer invasive species from one water body 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 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).[268]

[268] Alpha, 2009, p. 3-19, with updates from DEC.

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.[269]

Depletion of both groundwater and surface water can occur when significant 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[270]

As noted in later in this chapter, it is estimated that within 30 years there could be up to 40,000 wells developed with the high-volume hydraulic fracturing technology. This could result in substantial water usage in the study area. There are several potential types of impacts, when considered cumulatively, that could result from these estimated new withdrawals associated with natural gas development. Those are:

- Stream flow, surface water and groundwater depletion;
- Loss of aquifer storage capacity due to compaction;
- Water quality degradation;
- Wetland hydrology and habitat;

[269] Alpha, 2009, p. 81.

[270] Alpha, 2009 pp. 3-28.

- Fish and aquatic organism impacts;
- Significant habitats, endangered, rare or threatened species impacts; and
- Existing water users and reliability of their supplies.

Evaluation of the overall impact of multiple water withdrawals based on the projection of maximum activity consider the existing water usage, the non-continuous nature of withdrawals for natural gas development, and the natural replenishment of water resources. Natural replenishment is described in Section 2.3.8.

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 would 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; and
- Protection of subsurface infrastructure.

Existing Regulatory Scheme for Water Usage and Withdrawals

The DRBC and SRBC 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 is also 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.

The recently enacted Water Resources Law extends the Department's authority to regulate all water withdrawals over 100,000 gpd throughout all of New York State. This law applies to all such withdrawals where water would be used for high-volume hydraulic fracturing. Withdrawal permits issued in the future by the Department, pursuant to the regulations implementing this law, would include conditions to allow the Department to monitor and enforce water quality and quantity standards, and requirements. The Department is beginning the process for enacting regulations on this new law. These standards and requirements may include: passby flow; fish impingement and entrainment protections; protections for aquatic life; reasonable use; water conservation practices; and evaluation of cumulative impacts on other water withdrawals. The Department intends to seek consistency in water resource management within New York between the DRBC, SRBC and the Department.

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 to 10 billion gpd, based on data from 2000. Figure 6.2 presents fresh water use in New York, including the projected peak water use for high-volume hydraulic fracturing.

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 million gpd (65%), followed by 875 million gpd (10%) for public water supply, 650 million gpd (7.4%) for the NYC public water supply, 617 million gpd (7%) for hydroelectric, and 501 million gpd (5.7%) for industrial purposes. The amount of water used for mining is 70 million gpd (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% (14 million gpd) of the water withdrawn for consumptive use is for mining and 88% (650 million gpd) of water exported from the Delaware River Basin is diverted to NYC.

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% consumptive losses because this water is essentially lost to the basin's hydrologic cycle.

Withdrawals for High-Volume Hydraulic Fracturing

Current water withdrawal volumes when compared to withdrawal volumes associated with current natural gas drilling indicates that the historical percentage of withdrawn water that goes to natural gas drilling is very low. The amount of water withdrawn specifically for high-volume hydraulic fracturing also is projected to be relatively low when compared to existing overall levels of water use. The total volume of water withdrawn for high-volume hydraulic fracturing in New York would not be known with precision until applications are received, reviewed, and potentially approved or rejected by the appropriate regulatory agency or agencies, but can be estimated based on activity in Pennsylvania and projections of potential levels of well drilling activity in New York.

Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells.[271] Current practice is to use 80% - 90% fresh water and 10% - 20% recycled flowback water for high-volume hydraulic fracturing.[272] Average fresh water use as 85% of the total used per well is consistent with statistics reported by the SRBC.[273] This would equate to average fresh water use of 3.6 million gallons per well (85% of 4.2 million gallons). Industry projects a potential peak annual drilling rate in New York of 2,462 wells, a level of drilling that is projected to be at the very high end of activity. Although some of these wells may be vertical wells which require less water than horizontal wells where high-volume hydraulic fracturing is planned, all of the wells reflected in the peak drilling rate will be conservatively considered to be horizontal wells for the purpose of this analysis. Multiplying the peak projected annual wells by current average use per well results in calculated peak *annual* fresh water usage for high-volume hydraulic fracturing of 9 billion gallons. Total *daily* fresh water withdrawal in New York has been estimated at approximately 10.3 billion gallons.[274] This equates to an annual total of about 3.8 trillion gallons. Based on this calculation, at peak activity high-volume hydraulic fracturing would result in increased demand for fresh water in New York of 0.24%. The potential relationship between water use for high-volume hydraulic fracturing and other purposes is shown in Figure 6.2.

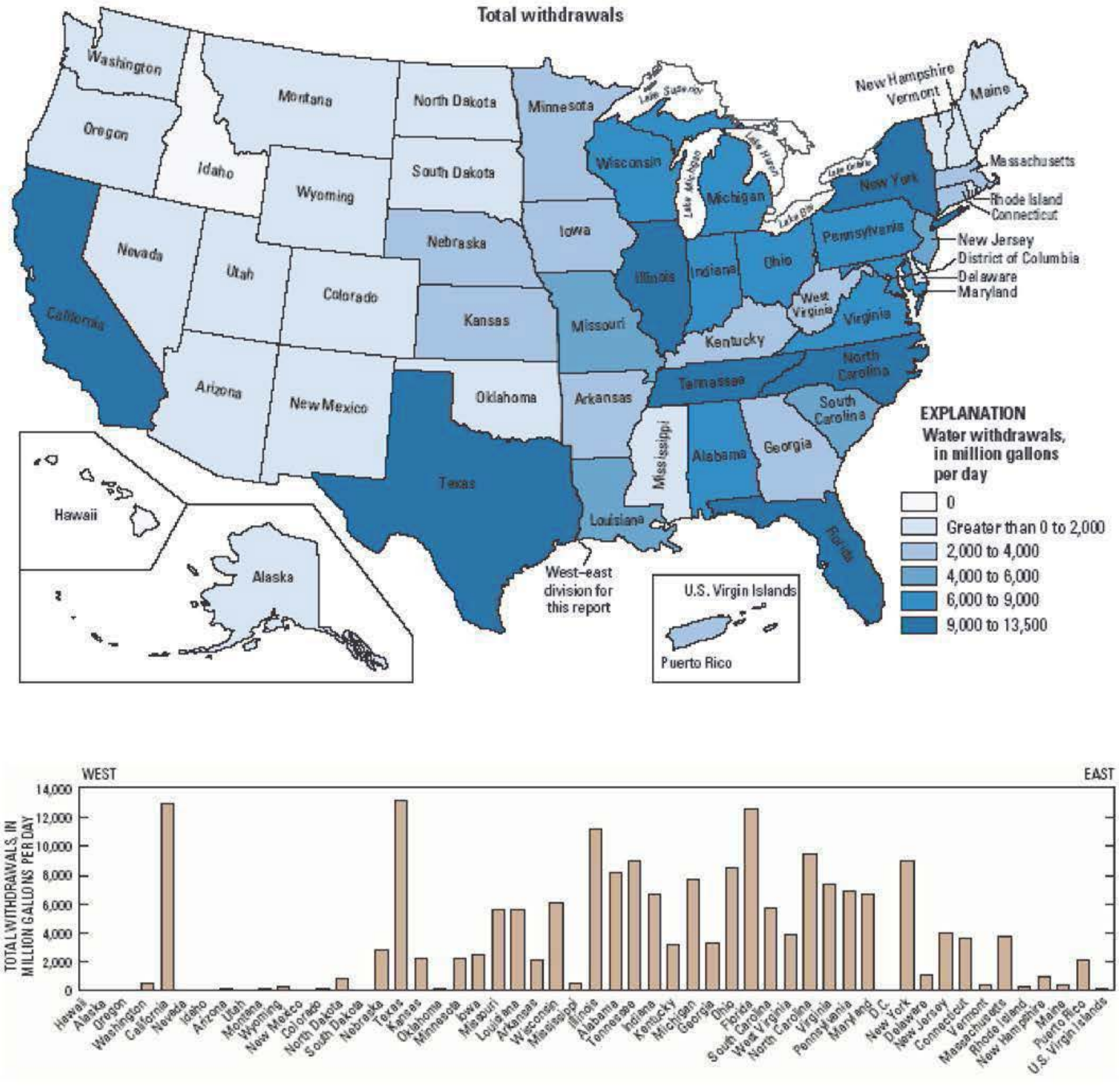
While projected water withdrawals and consumptive use of water are modest relative to overall water withdrawals in New York, there remains the potential for adverse impacts particularly when withdrawals take place during low-flow or drought conditions. Adverse impacts previously discussed may also occur when high or unsustainable withdrawals take place in localized ground or surface water that lack adequate hydrologic capacity.

[271] SRBC 2011.

[272] ALL Consulting, 2010, p. 74.

[273] Richenderfer, 2010, p. 30.

[274] Kenny et al, 2009, p.7.



Source: USGS

FIGURE 6.1

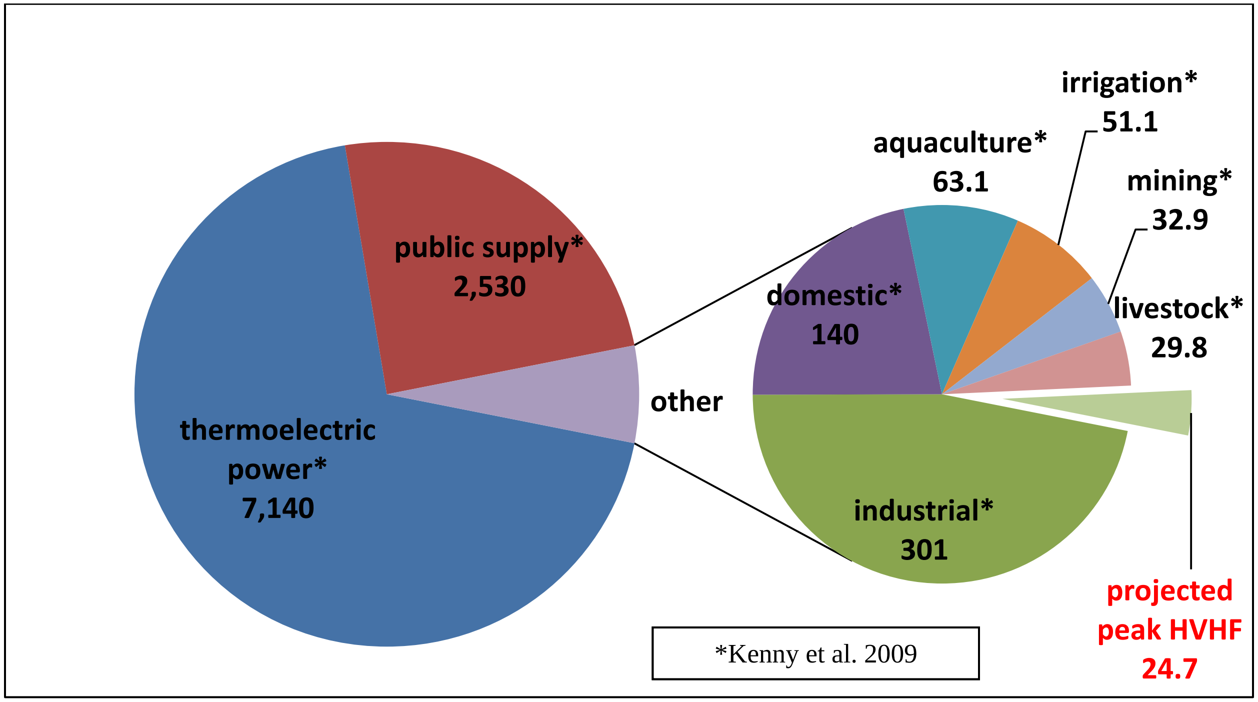
WATER WITHDRAWALS IN THE UNITED STATES

ALPHA GEOSCIENCE
Alpha Project No. 09104

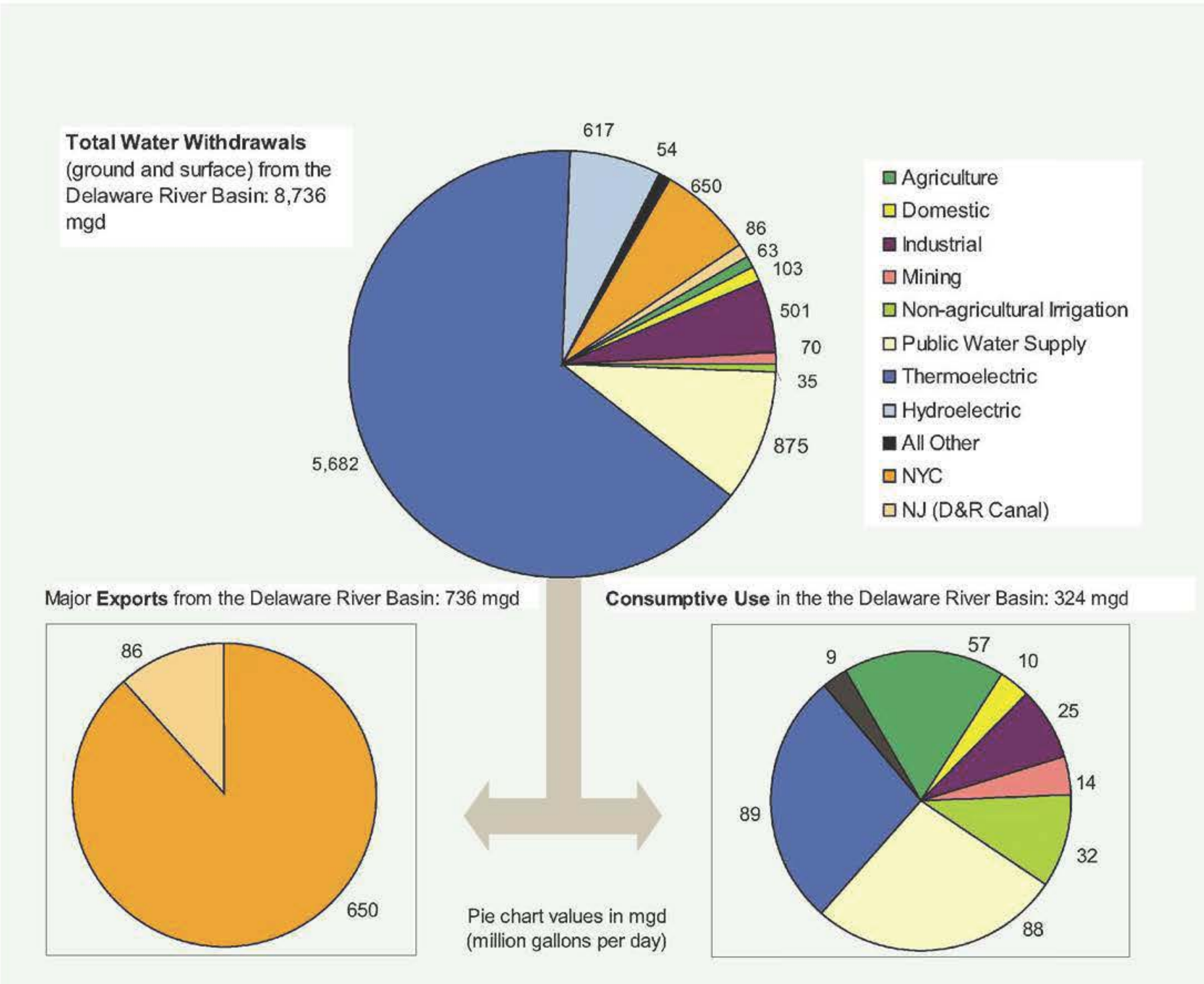
Technical Support Document to the Final Supplemental Generic Environmental Impact Statement

Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-2-NY_Water_Usage.cvx)

Figure 6.2 - Fresh Water Use in NY (millions of gallons per day) with Projected Peak Water Use for High-Volume Hydraulic Fracturing (New July 2011[275])



[275] This figure is a replacement for Figure 6.2 in the 2009 draft SGEIS which was a bar graph prepared by SRBC showing projected water use in the Susquehanna River Basin.



Source: DRBC

FIGURE 6.3

DAILY WATER WITHDRAWALS, EXPORTS, AND CONSUMPTIVE USES IN THE DELAWARE RIVER BASIN

ALPHA GEOSCIENCE
Alpha Project No. 09104

Technical Support Document to the Final Supplemental Generic Environmental Impact Statement

Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-3-DRBC.cvx)

6.1.2 Stormwater Runoff

Stormwater, whether as a result of rainfall or snowmelt, is a valuable resource. It is the source of water for lakes and streams, as well as aquifers. However, stormwater runoff, particularly when it interacts with the human environment, is a pathway for contaminants to be conveyed from the land surface to streams and lakes and groundwater. This is especially true for stormwater runoff from asphalt, concrete, gravel/dirt roads, other impervious surfaces, outdoor industrial activity, and earthen construction sites, where any material collected on the ground is washed into a nearby surface water body. Stormwater runoff may also contribute to heightened peak flows and flooding.

On an undisturbed landscape, precipitation is held by vegetation and pervious 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 through base flow 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 quickly with greater force and significantly higher volumes. 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 flooding.

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.

Excess sediment can fill or bury the rock cobble of streams that serve as spawning habitat for fish and the macro-invertebrate insects that serve as their food source. Stormwater runoff and heightened sediment loads carry excess levels of nutrient phosphorus and nitrogen that is a major cause of algae bloom, low dissolved oxygen and other water-quality impairments.

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 discussed above because its hydrologic characteristics, sediment, nutrient, contaminant, and water volumes may be substantially different from the pre-developed condition.

6.1.3 Surface Spills and Releases at the Well Pad

Spills or releases can occur as a result of tank ruptures, piping failures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, drilling and production equipment defects, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers.

To evaluate potential health impacts from spills or releases of additives, fracturing fluid containing diluted additives or residual diluted additive chemicals in flowback water, the NYSDOH reviewed the composition of additives proposed for high-volume hydraulic fracturing in New York. The NYSDOH concluded that the proposed additives 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 1992 GEIS.

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 inadequate surface and subsurface fluid containment practices, poor casing construction, or accidental spills and releases including well blow-outs during drilling or well component failures during completion operations. A release could also occur during a blow-out event if there are not trained personnel on site that are educated in the proper use of the BOP system. 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 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient. Concerns are heightened if on-site pits for 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 including failure of wellhead components during hydraulic fracturing. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged 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 5.7 and grouped into categories recommended by NYSDOH in Table 5.8. URS compared the list of additive chemicals to the parameters regulated via federal and state primary or secondary drinking water standards, SPDES discharge limits (see Section 7.1.8), and DOW Technical and Operational Guidance Series 1.1.1 (TOGS111), *Ambient Water Quality Standards and Guidance*

Values and Groundwater Effluent Limitations.[276,277] In NYS, the state drinking water standards (10 NYCRR 5) apply to all public water supplies and set maximum contaminant levels (MCLs) for essentially all organic chemicals in public drinking water. See Table 6.1.

6.1.3.3 Flowback Water and Production Brine

Gelling agents, surfactants and chlorides are identified in the 1992 GEIS as the flowback water components of greatest environmental concern.[278] Other flowback components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. Opportunities for spills, leaks, and operational errors during the flowback water recovery stage are the same as they are during the prior stages with additional potential releases from:

- hoses or pipes used to convey flowback water to tanks or a tanker truck for transportation to a treatment or disposal site; and
- tank leakage.

In general, *flowback water* is water and associated chemical constituents returning from the borehole during or proximate in time to hydraulic fracturing activities. *Production brine*, on the other hand, is fluid that returns from the borehole after completion of drilling operations while natural gas production is underway. The chemical characteristics and volumes of flowback water and production brine are expected to differ in significant respects.

Flowback water composition based on a limited number of out-of-state samples from Marcellus wells is presented in Table 5.9. A comparison of detected flowback parameters, except radionuclides, to regulated parameters is presented in Table 6.1.[279]

Table 5.10 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 Column 4. The minimum, median and maximum concentrations detected are indicated in

[276] URS, 2009, p. 4-18, et seq.

[277] http://www.dec.ny.gov/regulations/2652.html.

[278] NYSDEC, 1992, GEIS, p. 9-37.

[279] URS, 2009, p. 4-18, et seq.

Columns 5, 6 and 7.[280] Radionuclides data is presented in Chapter 5, and potential impacts and regulation are discussed in Section 6.7.

Table 5.11 lists parameters found in the flowback analyses that are not regulated in New York. Column 2 shows the number of samples that were analyzed for the particular parameter; column 3 indicates the number of samples in which the parameter was detected.[281]

Information presented in Tables 5.10 and 5.11 are based on limited data from Pennsylvania and West Virginia. Samples were not collected specifically for this type of analysis or under the Department'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.[282]

[280] URS, 2009, pp. 4-10, 4-31 et seq.

[281] URS, 2009, pp. 4-10, p. 4-35.

[282] URS, 2009, 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 (Revised August 2011)[283, 284]

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
106-24-1	(2E)-3,7-dimethylocta-2,6-dien-1-ol	Yes					0.05

[283] Table 6.1 was compiled by URS Corporation, 2011 and revised by the Department in coordination with NYSDOH.

[284] This table includes parameters detected in the MSC Study.

[285] Information in the "Used in Additives" column is based on the composition of additives used or proposed for use in New York.

[286] Parameters marked with ¥ indicates that the compound dissociates, and its components are separately regulated. Not all dissociating compounds are marked.

[287] 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 Department does not have chemical composition data. Blank entries in the "Found in Flowback" column indicate that the parameter was either not sampled for or not detected in the flowback.

[288] USEPA Maximum Contaminant Level (MCL) - The highest level of a contaminant that is allowed in drinking water. MCLs are set as close to MCLGs as feasible using the best available treatment technology and taking cost into consideration. MCLs are enforceable standards. From USEPA Title 40, Part 141--National Primary Drinking Water Regulations.

[289] USEPA Treatment Technique (TT) – A required process intended to reduce the level of a contaminant in drinking water. From USEPA Title 40, Part 141 – National Primary Drinking Water Regulations.

[290] 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 this table. Flowback analyses provided information for the total and dissolved components of metals. Understanding the dissolved vs. suspended portions of a substance is valuable when determining potential treatment techniques.

[291] 10 NYCRR Part 5-1.50 through 5-1.52. Under 10 NYCRR Part 5, organic contaminants (with very few exceptions) have either a Specific MCL (28 compounds plus 1 chemical mixture) or a General MCL of 0.05 mg/L for Unspecified Organic Contaminants (UOC) or 0.005 mg/L for Principal Organic Contaminants (POC). A total UOC + POC MCL of 0.1 mg/L also applies to all organic contaminants in drinking water. 10 NYCRR Part 5 also contains 23 MCLs for inorganic contaminants. A section sign (§) indicates that, for organic salts, the free compound (the expected form in drinking water) would be a UOC, but that salts themselves would not be UOC. A double section sign (§§) indicates that, for parameters listed as a group or mixture of related chemicals (e.g., Ethoxylated alcohol (C14-15), petroleum distillates, essential oils) a state MCL does not apply to the group as a whole, but would apply to each individual component of the group if detected in drinking water. A triple section sign (§§§) indicates that, for parameters listed as a polymer, the UOC MCL would apply to the polymer itself, but either the UOC or POC MCL would apply to the individual monomer components. An asterisk (*) indicates that the total trihalomethane (THM) MCL of 0.08 mg/L also applies.

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
67701-10-4	(C8-C18) And (C18) Unsaturated Alkylcarboxylic Acid Sodium Salt	Yes					§,§§
02634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one	Yes					0.05
00087-61-6	1,2,3-Trichlorobenzene		Yes		Table 9	Tables 1,5	0.005
00095-63-6	1,2,4-Trimethylbenzene	Yes	Yes		Table 9	Tables 1,5	0.005
93858-78-7	1,2,4-Butanetricarboxylicacid, 2-phosphono-, potassium salt	Yes					0.05
00108-67-8	1,3,5-Trimethylbenzene		Yes		Tables 9,10	Tables 1,5	0.005
00123-91-1	1,4 Dioxane	Yes			Table 8		0.05
03452-07-1	1-eicosene	Yes					0.05
00629-73-2	1-hexadecene	Yes					0.05
104-46-1	1-Methoxy-4-propenylbenzene	Yes					0.05
124-28-7	1-Octadecanamine, N, N-dimethyl- / N,N-Timethyloctadecylamine	Yes					0.05
112-03-8	1-Octadecanaminium, N,N,N-Trimethyl-, Chloride /Trimethyloctadecylammonium chloride	Yes					0.05
00112-88-9	1-octadecene	Yes					0.05
40623-73-2	1-Propanesulfonic acid	Yes					0.05
01120-36-1	1-tetradecene	Yes					0.05
98-55-5	2-(4-methyl-1-cyclohex-3-enyl)propan-2-ol	Yes					0.05
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					0.05
73003-80-2	2,2-Dibromomalonamide	Yes					0.05
00105-67-9	2,4-Dimethylphenol		Yes		Table 6	Tables 1,5	0.05
00087-65-0	2,6-Dichlorophenol		Yes		Table 8		0.005
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer	Yes					0.05
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride	Yes					0.05
00052-51-7	2-Bromo-2-nitro-1,3-propanediol	Yes			Table 10		
00111-76-2	2-Butoxy ethanol /Ethylene glycol monobutyl ether / Butyl Cellusolve	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
01113-55-9	2-Dibromo-3-Nitriloprionamide / 2-Monobromo-3-nitrilopropionamide	Yes					0.05
00104-76-7	2-Ethyl Hexanol	Yes					0.05
00091-57-6	2-Methylnaphthalene		Yes		Table 8	Tables 1,3	0.05
00095-48-7	2-Methylphenol		Yes		Table 8		0.05
109-06-8	2-Picoline (2-methyl pyridine)		Yes		Table 8	Table 3	0.05
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol	Yes	Yes		Table 10		0.05
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer	Yes					0.05
95077-68-2	2-Propenoic acid, homopolymer sodium salt	Yes					0.05
09003-03-6	2-propenoic acid, homopolymer, ammonium salt	Yes					0.05
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate	Yes					0.05
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)	Yes					0.05
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite	Yes					0.05
00107-19-7	2-Propyn-1-ol / Progargyl Alcohol	Yes					0.05
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,	Yes					0.05
106-22-9	3,7 - dimethyl-6-octen-1-ol	Yes					0.05
5392-40-5	3,7-dimethyl-2,6-octadienal	Yes					0.005
00115-19-5	3-methyl-1-butyn-3-ol	Yes					0.05
00108-39-4	3-Methylphenol		Yes		Table 8		0.05
104-55-2	3-phenyl-2-propenal	Yes					0.005
127-41-3	4-(2,6,6-trimethyl-1-cyclohex-2-enyl)-3-buten-2-one	Yes					0.05
00072-55-9	4,4 DDE		Yes		Table 6	Tables 1,5	0.005
121-33-5	4-hydroxy-3-methoxybenzaldehyde	Yes					0.05
00106-44-5	4-Methylphenol		Yes		Table 8		0.05
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
00057-97-6	7,12-Dimethylbenz(a)anthracene		Yes		Table 8	Table 3	0.05
00064-19-7	Acetic acid	Yes	Yes		Table 10		0.05
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	Yes					0.05
00108-24-7	Acetic Anhydride	Yes			Table 10		0.05
00067-64-1	Acetone	Yes	Yes		Table 7	Tables 1,5	0.05
00098-86-2	Acetophenone		Yes			Table 3	0.05
00079-06-1	Acrylamide	Yes		TT	Table 9	Tables 1,5	0.005
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	Yes					0.05
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide	Yes					0.05
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					0.05
15085-02-3	Acrylamide-sodium acrylate copolymer	Yes					0.05
00107-13-1	Acrylonitrile		Yes		Table 6	Tables 1,5	
68891-29-2	Alcohols C8-10, ethoxylated, monoether with sulfuric acid, ammonium salt	Yes					§,§§
68526-86-3	Alcohols, C11-14-iso-, C13-rich	Yes					§§
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)	Yes					§§
00309-00-2	Aldrin		Yes			Tables 1,5	
	Aliphatic acids	Yes					§§
	Aliphatic alcohol glycol ether	Yes					0.05
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent	Yes					§§
	Alkalinity, Carbonate, as $CaCO_3$		Yes		Table 10		
64743-02-8	Alkenes	Yes					§§
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt	Yes					0.05
	Alkyl Aryl Polyethoxy Ethanol	Yes					0.05
	Alkylaryl Sulfonate	Yes					0.05
09016-45-9	Alkylphenol ethoxylate surfactants	Yes					§§
07439-90-5	Aluminum		Yes		Table 7	Tables 1,5	
01327-41-9	Aluminum chloride	Yes (¥)					

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
68155-07-7	Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)	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 (¥)					0.05
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		
	Anionic copolymer	Yes					
07440-36-0	Antimony		Yes	0.006	Table 6	Tables 1,5	0.006
07664-41-7	Aqueous ammonia	Yes	Yes		Table 7	Tables 1,5	
12672-29-6	Aroclor 1248		Yes		Table 6		0.0005
	Aromatic hydrocarbons	Yes					§§
	Aromatic ketones	Yes					§§
07440-38-2	Arsenic		Yes	0.01	Table 6	Tables 1,5	0.01
12174-11-7	Attapulgite Clay	Yes					
07440-39-3	Barium		Yes	2	Table 7	Tables 1,5	2
	Barium Strontium P.S. (mg/L)		Yes				
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay	Yes					
00071-43-2	Benzene	Yes	Yes	0.005	Table 6	Tables 1,5	0.005
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback [287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	Yes					0.05
122-91-8	Benzenemethanol,4-methoxy-, 1-formate	Yes					0.05
1300-72-7	Benzenesulfonic acid, Dimethyl-, Sodium salt (aka Sodium xylene sulfonate)	Yes					0.05
00050-32-8	Benzo(a)pyrene		Yes		Table 6		0.0002
00205-99-2	Benzo(b)fluoranthene		Yes			Tables 1,5	0.05
00191-24-2	Benzo(ghi)perylene		Yes		Table 6	Table 3	0.05
00207-08-9	Benzo(k)fluoranthene		Yes		Table 6	Tables 1,5	0.05
140-11-4	Benzyl acetate	Yes					0.05
00100-51-6	Benzyl alcohol		Yes		Table 8	Table 3	0.05
07440-41-7	Beryllium		Yes	0.004	Table 6	Tables 1,5	0.004
	Bicarbonates (mg/L)		Yes		Table 10		
76-22-2	Bicyclo (2.2.1) heptan-2-one, 1,7,7-trimethyl-	Yes					0.05
	Biochemical Oxygen Demand		Yes		Yes		
00111-44-4	Bis(2-Chloroethyl) ether		Yes		Table 6	Tables 1,5	0.005
00117-81-7	Bis(2-ethylhexyl)phthalate / Di(2-ethylhexyl)phthalate		Yes	0.006	Table 6	Tables 1,5	0.006
68153-72-0	Blown lard oil amine	Yes					§§
68876-82-4	Blown rapeseed amine	Yes					§§
1319-33-1	Borate Salt	Yes					
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	0.005*
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	Table 6	Tables 1,5	0.005
07440-70-2	Calcium		Yes		Table 8		
1317-65-3	Calcium Carbonate	Yes			Table 10		
10043-52-4	Calcium chloride	Yes (¥)					

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
1305-62-0	Calcium Hydroxide	Yes					
1305-79-9	Calcium Peroxide	Yes					
00124-38-9	Carbon Dioxide	Yes	Yes				
00075-15-0	Carbondisulfide		Yes		Table 8	Tables 1,5	
68130-15-4	Carboxymethylhydroxypropyl guar	Yes					§§§
09012-54-8	Cellulase / Hemicellulase Enzyme	Yes					§§§
09004-34-6	Cellulose	Yes					§§§
	Cesium 137		Yes	Via beta radiation			Via beta radiation
	Chemical Oxygen Demand		Yes		Yes		
	Chloride		Yes		Table 7	Tables 1,5	250
10049-04-4	Chlorine Dioxide	Yes		MRDL=0.8	Table 10		MRDL=0.8
00124-48-1	Chlorodibromomethane		Yes		Table 6	Tables 1,5	0.005*
00067-66-3	Chloroform		Yes		Table 6	Tables 1,5	0.005*
78-73-9	Choline Bicarbonate	Yes					§
67-48-1	Choline Chloride	Yes					§
91-64-5	Chromen-2-one	Yes					0.05
07440-47-3	Chromium		Yes	0.1	Table 6	Tables 1,5	0.1
00077-92-9	Citric Acid	Yes					0.05
94266-47-4	Citrus Terpenes	Yes					§§
07440-48-4	Cobalt		Yes		Table 7	Table 1	
61789-40-0	Cocamidopropyl Betaine	Yes					0.05
68155-09-9	Cocamidopropylamine Oxide	Yes					0.05
68424-94-2	Coco-betaine	Yes					0.05
	Coliform, Total		Yes	0.05	Table 7		
	Color		Yes		Table 7		
07440-50-8	Copper		Yes	TT; Action Level=1.3	Table 6	Tables 1,5	Action Level = 1.3
07758-98-7	Copper (II) Sulfate	Yes (¥)					
14808-60-7	Crystalline Silica (Quartz)	Yes		Via solids and TSS			
07447-39-4	Cupric chloride dihydrate	Yes (¥)					
00057-12-5	Cyanide		Yes	0.2	Table 6	Tables 1,5	0.2

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
00319-85-7	Cyclohexane (beta BHC)		Yes		Table 6	Tables 1,5	0.005
00058-89-9	Cyclohexane (gamma BHC)		Yes	0.0002	Table 6	Tables 1,5	0.0002
1490-04-6	Cyclohexanol,5-methyl-2-(1-methylethyl)	Yes					0.05
8007-02-1	Cymbopogon citratus leaf oil	Yes					§§
8000-29-1	Cymbopogon winterianus jowitt oil	Yes					§§
01120-24-7	Decyldimethyl Amine	Yes (¥)					0.05
02605-79-0	Decyl-dimethyl Amine Oxide	Yes (¥)					0.05
00055-70-3	Dibenz(a,h)anthracene		Yes			Table 3	0.05
03252-43-5	Dibromoacetonitrile	Yes			Table 9	Tables 1	0.05
00075-27-4	Dichlorobromomethane		Yes		Table 6	Tables 1,5	0.005*
25340-17-4	Diethylbenzene	Yes					0.05
00111-46-6	Diethylene Glycol	Yes			Table 10		0.05
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt	Yes					0.05
28757-00-8	Diisopropyl naphthalenesulfonic acid	Yes					0.05
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt	Yes					0.05
07398-69-8	Dimethyldiallylammonium chloride	Yes					0.05
00084-74-2	Di-n-butyl phthalate		Yes		Table 6	Tables 1,5	0.05
00122-39-4	Diphenylamine		Yes		Table 7	Tables 1,5	0.005
25265-71-8	Dipropylene glycol	Yes					0.05
34590-94-8	Dipropylene glycol methyl ether	Yes					0.05
00139-33-3	Disodium Ethylene Diamine Tetra Acetate	Yes					0.05
64741-77-1	Distillates, petroleum, light hydrocracked	Yes					§§
05989-27-5	D-Limonene	Yes					0.05
00123-01-3	Dodecylbenzene	Yes					0.05
27176-87-0	Dodecylbenzene sulfonic acid	Yes					0.05
42504-46-1	Dodecylbenzenesulfonate isopropanolamine	Yes					0.05
00050-70-4	D-Sorbitol / Sorbitol	Yes					0.05
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase	Yes					0.05
00959-98-8	Endosulfan I		Yes		Table 6	Table 3	0.05
33213-65-9	Endosulfan II		Yes		Table 6	Table 3	0.05
07421-93-4	Endrin aldehyde		Yes		Table 6	Tables 1,5	0.005
149879-98-1	Erucic Amidopropyl Dimethyl Betaine	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
00089-65-6	Erythorbic acid, anhydrous	Yes					0.05
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	Yes					0.05
00107-21-1	Ethane-1,2-diol / Ethylene Glycol	Yes	Yes		Table 7	Tables 1,5	0.05
111-42-2	Ethanol, 2,2-iminobis-	Yes					0.05
26027-38-3	Ethoxylated 4-nonylphenol	Yes					0.05
09002-93-1	Ethoxylated 4-tert-octylphenol	Yes					0.05
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					§§
67254-71-1	Ethoxylated Alcohols (C10-12)	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					§§
78330-21-8	Ethoxylated C11-14-iso, C13-rich alcohols	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					0.05
09005-67-8	Ethoxylated Sorbitan Monostearate	Yes					0.05
09005-70-3	Ethoxylated Sorbitan Trioleate	Yes					0.05
118-61-6	Ethyl 2-hydroxybenzoate	Yes					0.05
00064-17-5	Ethyl alcohol / ethanol	Yes					0.05
00100-41-4	Ethyl Benzene	Yes	Yes	0.7	Table 6	Tables 1,5	0.005
93-89-0	Ethyl benzoate	Yes					0.05
00097-64-3	Ethyl Lactate	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
09003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)	Yes					0.05
00075-21-8	Ethylene oxide	Yes			Table 9	Tables 1,5	0.05
05877-42-9	Ethyloctynol	Yes					0.05
8000-48-4	Eucalyptus globulus leaf oil	Yes					§§
61790-12-3	Fatty Acids	Yes					§§
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine	Yes					§§
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	Yes					§§
09043-30-5	Fatty alcohol polyglycol ether surfactant	Yes					§§
07705-08-0	Ferric chloride	Yes			Table 10		
07782-63-0	Ferrous sulfate, heptahydrate	Yes					
00206-44-0	Fluoranthene		Yes		Table 6	Tables 1,5	0.05
00086-73-7	Fluorene		Yes		Table 6	Tables 1,5	0.05
16984-48-8	Fluoride		Yes	4	Table 7	Tables 1,5	2.2
00050-00-0	Formaldehyde	Yes			Table 8	Tables 1,5	
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	Yes					0.05
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	Yes					0.05
00075-12-7	Formamide	Yes					0.05
00064-18-6	Formic acid	Yes			Table 10		0.05
00110-17-8	Fumaric acid	Yes			Table 10		0.05
65997-17-3	Glassy calcium magnesium phosphate	Yes					
00111-30-8	Glutaraldehyde	Yes					0.05
00056-81-5	Glycerol / glycerine	Yes					0.05
09000-30-0	Guar Gum	Yes					0.05
64742-94-5	Heavy aromatic petroleum naphtha	Yes					0.05
09025-56-3	Hemicellulase	Yes					0.05
00076-44-8	Heptachlor		Yes	0.0002		Tables 1,5	0.0004
01024-57-3	Heptachlor epoxide		Yes	0.0002		Tables 1,5	0.0002

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
	Heterotrophic plate count		Yes	TT[292]			
07647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid	Yes					
07722-84-1	Hydrogen Peroxide	Yes			Table 10		
64742-52-5	Hydrotreated heavy napthenic distillate	Yes					§§
00079-14-1	Hydroxy acetic acid	Yes					0.05
35249-89-9	Hydroxyacetic acid ammonium salt	Yes					0.05
09004-62-0	Hydroxyethyl cellulose	Yes					0.05
05470-11-1	Hydroxylamine hydrochloride	Yes					0.05
39421-75-5	Hydroxypropyl guar	Yes					0.05
00193-39-5	Indeno(1,2,3-cd)pyrene		Yes		Table 6	Tables 1,5	0.05
07439-89-6	Iron		Yes		Table 7	Tables 1,5	0.3
35674-56-7	Isomeric Aromatic Ammonium Salt	Yes					0.05
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic	Yes					§§
00064-63-0	Isopropanol	Yes			Table 10		0.05
00098-82-8	Isopropylbenzene (cumene)	Yes	Yes		Table 9	Tables 1,5	0.005
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	Yes					0.05
08008-20-6	Kerosene	Yes					§§
64742-81-0	Kerosine, hydrodesulfurized	Yes					§§
00063-42-3	Lactose	Yes					
8022-15-9	Lavandula hybrida abrial herb oil	Yes					§§
07439-92-1	Lead		Yes	TT; Action Level 0.015	Table 6	Tables 1,5	Action level = 0.015
64742-95-6	Light aromatic solvent naphtha	Yes					§§
01120-21-4	Light Paraffin Oil	Yes					§§
	Lithium		Yes		Table 10		
07439-95-4	Magnesium		Yes		Table 7	Tables 1,5	
546-93-0	Magnesium Carbonate	Yes					
1309-48-4	Magnesium Oxide	Yes					

[292] Treatment Technology specified.

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
1335-26-8	Magnesium Peroxide	Yes					
14807-96-6	Magnesium Silicate Hydrate (Talc)	Yes					
07439-96-5	Manganese		Yes		Table 7	Tables 1,5	0.3
07439-97-6	Mercury		Yes	0.002	Table 6	Tables 1,5	0.002
01184-78-7	Methanamine, N,N-dimethyl-, N-oxide	Yes					0.05
00067-56-1	Methanol	Yes	Yes		Table 10		0.05
119-36-8	Methyl 2-hydroxybenzoate	Yes					0.05
00074-83-9	Methyl Bromide		Yes		Table 6	Tables 1,5	0.005
00074-87-3	Methyl Chloride / chloromethane		Yes	0.005	Table 6	Tables 1,5	0.005
00078-93-3	Methyl ethyl ketone / 2-Butanone		Yes		Table 7	Tables 1,5	0.05
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	Yes					0.05
08052-41-3	Mineral spirits / Stoddard Solvent	Yes					§§
64742-46-7	Mixture of severely hydrotreated and hydrocracked base oil	Yes					§§
07439-98-7	Molybdenum		Yes		Table 7		
00141-43-5	Monoethanolamine	Yes					0.05
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					0.05
64742-48-9	Naphtha (petroleum), hydrotreated heavy	Yes					§§
00091-20-3	Naphthalene	Yes	Yes		Table 6	Tables 1,5	0.05
38640-62-9	Naphthalene bis(1-methylethyl)	Yes					0.05
00093-18-5	Naphthalene, 2-ethoxy-	Yes					0.05
68909-18-2	N-benzyl-alkyl-pyridinium chloride	Yes					0.05
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	Yes					0.05
07440-02-0	Nickel		Yes		Table 6	Tables 1,5	
	Nitrate, as N		Yes	10	Table 7	Tables 1,5	10
07727-37-9	Nitrogen, Liquid form	Yes					
	Nitrogen, Total as N		Yes			Table 5	
00086-30-6	N-Nitrosodiphenylamine		Yes		Table 6	Tables 1,5	0.05
26027-38-3	Nonylphenol Ethoxylate	Yes					0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
68412-54-4	Nonylphenol Polyethoxylate	Yes					0.05
	Oil and Grease		Yes			Table 5	
8000-27-9	Oils, cedarwood	Yes					§§
121888-66-2	Organophilic Clays	Yes					
	Oxyalkylated alkylphenol	Yes					0.05
628-63-7	Pentyl acetate	Yes					0.05
540-18-1	Pentyl butanoate	Yes					0.05
8009-03-8	Petrolatum	Yes					§§
64742-65-0	Petroleum Base Oil	Yes					§§
	Petroleum distillate blend	Yes					
64742-52-5	Petroleum Distillates	Yes					§§
	Petroleum hydrocarbons		Yes				
64741-68-0	Petroleum naphtha	Yes					0.05
	pH		Yes			Table 5	
00085-01-8	Phenanthrene		Yes		Table 6	Tables 1,5	0.05
00108-95-2	Phenol		Yes		Table 6	Tables 1,5	0.05
	Phenols		Yes		Table 6	Tables 1,5	
101-84-8	Phenoxybenzene	Yes					0.05
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					§§
8002-09-3	Pine oils	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					§§§
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl- ω-hydroxy	Yes					§§§
31726-34-8	Poly(oxy-1,2-ethanediyl),alpha-hexyl-omega-hydroxy	Yes					§§§

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
9004-32-4	Polyanionic Cellulose	Yes					§§§
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized	Yes					§§§
56449-46-8	polyethlene glycol oleate ester	Yes					§§§
	Polyethoxylated alkanol	Yes					
9046-01-9	Polyethoxylated tridecyl ether phosphate	Yes					§§
63428-86-4	Polyethylene glycol hexyl ether sulfate, ammonium salt	Yes					§
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate	Yes					§§§
	Polymeric Hydrocarbons	Yes					§§
09005-65-6	Polyoxyethylene Sorbitan Monooleate	Yes					0.05
61791-26-2	Polyoxylated fatty amine salt	Yes					0.05
65997-18-4	Polyphosphate	Yes					
07440-09-7	Potassium		Yes		Table 8		
00127-08-2	Potassium acetate	Yes					§
1332-77-0	Potassium borate	Yes					
12712-38-8	Potassium borate	Yes					
20786-60-1	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	Yes		Table 10	Table 3[293]	1.0
00057-55-6	Propylene glycol						1.0
00107-98-2	Propylene glycol monomethyl ether	Yes			Table 10		0.05
00110-86-1	Pyridine		Yes		Table 7	Tables 1,5	0.05
68953-58-2	Quaternary Ammonium Compounds	Yes			Table 9	Tables 1	§§

[293] TOGS lists this parameter as CAS 58-55-6.

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
62763-89-7	Quinoline,2-methyl-, hydrochloride	Yes					0.05
15619-48-4	Quinolinium, 1-(phenylmethl),chloride	Yes					0.05
8000-25-7	Rosmarinus officinalis l. leaf oil	Yes					§§
00094-59-7	Safrole		Yes		Table 8	Table 3	0.05
	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	Table 6	Tables 1,5	0.05
07631-86-9	Silica, Dissolved	Yes			Table 8		
07440-22-4	Silver		Yes		Table 6	Tables 1,5	0.1
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					1.0 (chlorite)
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					§
1301-73-2	Sodium hydroxide	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					
68608-26-4	Sodium petroleum sulfonate	Yes					

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
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					0.05
	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		Table 7	Tables 1,5	250
	Sulfide		Yes		Table 7	Tables 1,5	
14265-45-3	Sulfite		Yes		Table 7	Table 1	
	Surfactant blend	Yes					
68442-77-3	Surfactant: Modified Amine	Yes					§§
	Surfactants MBAS		Yes				
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	0.005	Table 6	Tables 1,5	0.005
00533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione / Dazomet	Yes					0.05
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	Yes					0.05
00075-57-0	Tetramethyl ammonium chloride	Yes					§
00064-02-8	Tetrasodium Ethylenediaminetetraacetate	Yes					§
07440-28-0	Thallium		Yes	0.002	Table 6	Tables 1,5	0.002
00068-11-1	Thioglycolic acid	Yes					0.05
00062-56-6	Thiourea	Yes			Table 10		0.05

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L)[291]
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	Yes					§§§
68917-35-1	Thuja plicata donn ex. D. don leaf oil	Yes					§§
07440-32-6	Titanium		Yes		Table 7		
00108-88-3	Toluene	Yes	Yes	1	Table 6	Tables 1,5	0.005
	Total Dissolved Solids		Yes			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					§
	Triethanolamine	Yes					0.05
68299-02-5	Triethanolamine hydroxyacetate	Yes					0.05
00112-27-6	Triethylene Glycol	Yes					0.05
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated	Yes					§§
00150-38-9	Trisodium Ethylenediaminetetraacetate	Yes					§
05064-31-3	Trisodium Nitrilotriacetate	Yes					§0.05
07601-54-9	Trisodium ortho phosphate	Yes					
00057-13-6	Urea	Yes					0.05
07440-62-2	Vanadium		Yes		Table 7	Table 1	
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer	Yes					§§§
	Volatile Acids		Yes		[294]		
7732-18-5	Water	Yes					
8042-47-5	White Mineral Oil	Yes					§§
11138-66-2	Xanthan gum	Yes					§§§
	Xylenes	Yes	Yes	10		Table 1,5	0.005
13601-19-9	Yellow Sodium of Prussiate	Yes					
07440-66-6	Zinc		Yes		Table 6	Tables 1,5	5.0
	Zirconium		Yes				0.05

[294] Several volatile compounds regulated via SPDES Table 6. Need to evaluate constituents.

CAS Number	Parameter Name	Used in Additives[285, 286]	Found in Flowback[287]	USEPA MCL or TT (mg/L)[288, 289]	SPDES Tables[290]	TOGS111 Tables	NYS MCL, (mg/L) [291]
							§,§§

6.1.3.4 Potential Impacts to Primary and Principal Aquifers

An uncontained and unmitigated surface spill could result in rapid contamination of a portion of a Primary or Principal aquifer.

Aside from the NYC Watershed and water supply system, about one half of New Yorkers rely on groundwater as a source of potable water. To enhance regulatory protection in areas where groundwater resources are most highly productive and vulnerable, NYSDOH identified categories of areas for use in geographic targeting. In order of priority, these areas are designated as follows: public water supply wellhead areas; primary water supply aquifer areas; principal aquifer areas; and other areas. The Department's Division of Water Technical & Operational Guidance Series (TOGS) 2.1.3 clarifies the meaning of Primary Water Supply Aquifer (also referred to as a Primary Aquifer) and Principal Aquifer. TOGS 2.1.3 further defines "highly vulnerable" areas as "aquifers which are highly susceptible to contamination from human activities at the land surface over the identified aquifer." This TOGS also further defines "highly productive" aquifers as those "with capability to provide water for public water supply of a quantity and natural background quality which is of regional significance."

NYSDOH identified eighteen Primary Aquifers across New York State, defined in TOGS 2.1.3 as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems." Primary Aquifers are generally capable of providing more than 100 gallons of drinking water per minute from an individual well.

NYSDOH has also identified Principal Aquifers, which are defined in the TOGS as "highly productive but which are not intensively used as sources of water supply by major municipal systems at the present time." The TOGS further states that these areas need special protections, but awards Principal Aquifers a slightly lower priority than that afforded Primary Aquifers. Principal Aquifers are used by individual households, as well as smaller public water supply systems, such as schools or restaurants. However, Principal Aquifers are generally capable of providing 10 to 100 or more gpm of drinking water. Principal Aquifers could become Primary Aquifers depending on future public water supply use.

The groundwater table in the Primary and Principal Aquifers generally ranges from 0 to 20 feet in depth, and is overlain with sands and gravels. Because Primary and Principal Aquifers are largely located and contained in unconsolidated material (i.e., sand and gravel), the high permeability of soils that overlie these aquifers and the shallow depth to the water table make these aquifers particularly susceptible to contamination from surface activity. TOGS 2.1.3 notes that the aquifer designations provide a rationale for enhancing regulatory protections beyond those provided by existing programs including the SPDES, Chemical Bulk Storage, and Solid and Hazardous Wastes.

The Department has issued regulations prohibiting installation of certain facilities that threaten these aquifers. For example, 6 NYCRR Part 360 "Solid Waste Facilities" provides that landfills are generally not permitted to be constructed above, or within, Primary or Principal Aquifer areas. Likewise, the Department has, since 1982, inserted special conditions into permits for drilling oil, gas and other ECL 23 wells within the boundaries of these aquifers.

As an example of the number and distribution of public supply systems that rely on Primary and Principal Aquifers within areas that could be developed by high-volume hydraulic fracturing, Figure 6.4 depicts public water supply systems that draw from Primary and Principal Aquifers within the area underlain by the Marcellus Shale where the shale occurs at a depth of at least 2,000 feet below the ground surface. The Primary Aquifer areas in this area follow the major river valleys, and serve hundreds of public water supplies, including a number of significantly sized municipalities, such as Binghamton and Endicott, as well as their surrounding areas. There are approximately 1,074 public supply systems that rely on Primary and Principal Aquifers in this area, and the total population served by these combined water supplies is at least 544,740. The total population within the area is approximately 906,000. Therefore, roughly 60.1% of the population in this prospective area is served by community groundwater supplies that draw from Primary and Principal Aquifer areas. The remainder of the population in this area is served by individual private wells or public surface water supplies or community supplies outside of Primary and Principal Aquifer areas.

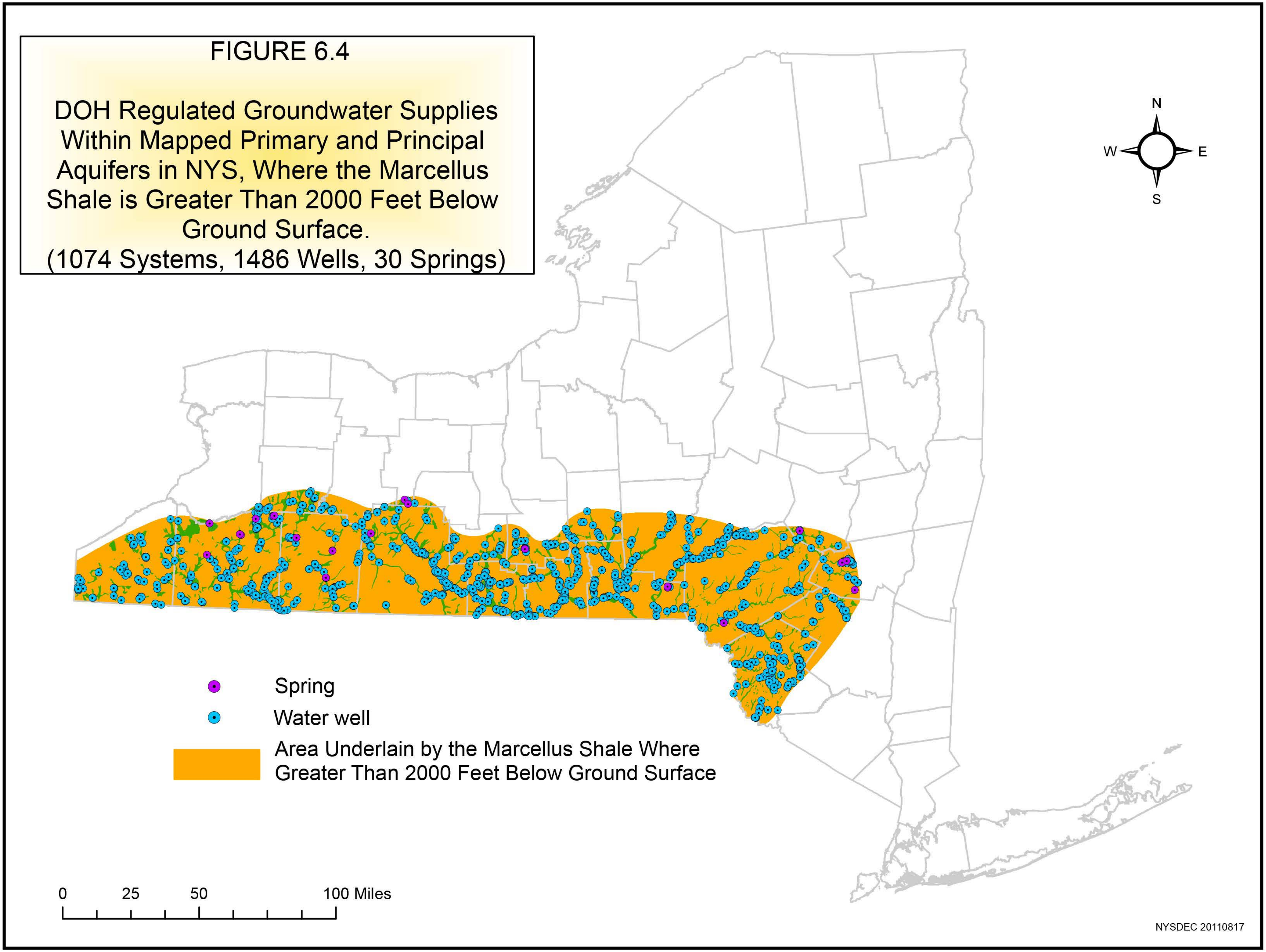


FIGURE 6.4
DOH Regulated Groundwater Supplies Within Mapped Primary and Principal Aquifers in NYS, Where the Marcellus Shale is Greater Than 2000 Feet Below Ground Surface.
(1074 Systems, 1486 Wells, 30 Springs)
N
W
E
S
Spring
Water well
Area Underlain by the Marcellus Shale Where Greater Than 2000 Feet Below Ground Surface
0
25
50
100 Miles
NYSDEC 20110817

The Department is chiefly concerned with surface contamination in Primary and Principal Aquifer areas because of the risk that uncontained and unmitigated surface spills could reach the aquifer in a short amount of time, due to the permeable character of the soils above the aquifers, and the shallow depth to the aquifers (generally 0-20 feet below the ground). Water quality management programs for such aquifers focus on preventing contaminants from reaching the waters in the first instance, because once they become contaminated, it is difficult and expensive to reclaim an aquifer as a source of drinking water.

As discussed elsewhere, detailed well pad containment requirements and setbacks proposed for high-volume hydraulic fracturing are likely to effectively contain most surface spills at and in the vicinity of well pads. Nevertheless, despite the best controls, there is a risk of releases to Primary or Principal Aquifers of chemicals, petroleum products and drilling fluids from the well pad.

Therefore, the Department concludes that high-volume hydraulic fracturing operations have the potential to cause a significant adverse impact to the quality of the drinking water resources provided by Primary and Principal Aquifers, even if the risk of such events is relatively small.

Conclusion

The Department finds that the proposed high-volume hydraulic fracturing operations, although temporary in nature, may pose risks to Primary and Principal Aquifers that are not fully mitigated by the measures identified in this SGEIS.

The proposed activity could result in a degradation of drinking water supplies from accidents, construction activity, runoff and surface spills. Accordingly, the Department concludes that high-volume hydraulic fracturing operations within Primary and Principal Aquifers pose the risk of causing significant adverse impacts to water resources. As discussed in Chapter 7, standard mitigation measures may only partially mitigate such impacts. Such partial mitigation would be unacceptable due to the potential consequences posed by such impacts.

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, has the potential to 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 1992 GEIS. The unique aspect of the proposed multi-well development method is that continuous or intermittent activities would 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 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. 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 1992 GEIS.

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."[295] This remains the case today. Turbidity, or suspension of solids in the water supply, can result from any aquifer penetration (including monitoring wells, water wells, oil and gas wells, mine shafts and construction pilings) if sufficient porosity and permeability or a natural subsurface fracture is present to transmit the disturbance. The majority of these situations correct themselves in a short time.

[295] NYSDEC 1992, GEIS, p. 47.

6.1.4.2 Fluids Pumped Into the Well

Fluids for hydraulic fracturing are pumped into the wellbore for a short period of time per fracturing stage, until the rock fractures and the proppant has been placed. For each horizontal well the total pumping time is generally between 40 and 100 hours. ICF International, under its contract with NYSERDA to conduct research in support of 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):[296]

> 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 would 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 x 10-8 (fewer than 1 in 50 million wells).*

More recently, regulatory officials from 15 states have testified that groundwater contamination as a result of hydraulic fracturing, which includes this pumping process, has not occurred (Appendix 15).

6.1.4.3 Natural Gas Migration

As discussed above, turbidity is typically a short-term problem which corrects itself as suspended particles settle. The probability of groundwater contamination from fluids pumped into a properly-constructed well is very low. Natural gas migration is a more reasonably anticipated risk posed by high-volume hydraulic fracturing. The 1992 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:

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[296] ICF Task 1, 2009, p. 21.

- 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 1992 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 form a barrier to 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 1992 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. Section 4.7 of this document explains how the natural occurrence of shallow methane in New York can affect water wells, which needs to be considered when evaluating complaints of methane migration that are perceived to be related to natural gas development.

6.1.5 Unfiltered Surface Drinking Water Supplies: NYC and Syracuse

There are two major surface drinking water sources and systems located within New York that have been granted permission by EPA and NYSDOH to operate as unfiltered drinking water supplies pursuant to regulations promulgated under the federal SDWA, known as the Surface Water Treatment Rule (SWTR). These unfiltered systems are the NYC and City of Syracuse water supplies and associated watersheds. For a drinking water system to qualify for filtration avoidance under the SWTR, the system cannot be the source of a waterborne disease outbreak, must meet source water quality limits for coliform and turbidity and meet coliform and total trihalomethane MCLs in finished water. Disinfectant residual levels and redundant disinfection capability also must be maintained. Filtration avoidance further requires that a watershed control program be implemented to minimize microbial contamination of the source water. This program must characterize the watershed's hydrology, physical features, land use, source water quality and operational capabilities. It must also identify, monitor and control manmade and naturally occurring activities that are detrimental to water quality. The watershed control program must also be able to control activities through land ownership or written agreements.

Heightened public health sensitivities are associated with unfiltered surface water systems because the only treatment that these drinking waters receive before human consumption is basic disinfection through such methods as chlorine addition or ultraviolet light irradiation. In unfiltered systems, there is no application of widely employed treatment measures such as chemical coagulation/flocculation or physical filtration to remove pathogens, sediments, organic matter or other contaminants from the drinking water.

The NYC drinking water supply watershed (NYC Watershed) is located in portions of Delaware, Dutchess, Greene, Putnam, Schoharie, Sullivan, Ulster and Westchester Counties. Approximately 9.4 million residents rely on the NYC water supply: 8.4 million in NYC and 1 million in portions of Orange, Putnam, Ulster and Westchester Counties. The NYC Watershed contains 19 reservoirs and 3 controlled lakes that supply, on average, 1.1 to 1.3 billion gallons of potable water daily. Historically, 90% of this system's drinking water has been supplied by the "Catskill" and "Delaware" portions of the NYC Watershed, which are located west of the Hudson River (an area that may be described as the "Catskill/Delaware Watershed"). On average, the remaining 10% of the water supply flows from the "Croton" portion of the NYC Watershed that is located in the counties to the east of the Hudson River. An extensive system of aqueducts and tunnels transmit waters by gravity throughout the NYC Watershed and water supply system. The NYC Watershed covers 2,000 square miles, an area that comprises 4.2% of the total land area of New York State.

Eight of the reservoirs located in the Croton portion of the NYC Watershed have been formally determined by the Department, pursuant to Clean Water Act sec. 303(d), to be impaired due to excess nutrient phosphorus (Amawalk, Croton Falls, Diverting, East Branch, Middle Branch, Muscoot, New Croton and Titicus Reservoirs). Designation as "impaired" means that these reservoirs are in a condition that violates state water quality standards due to a specified pollutant. The Cannonsville Reservoir in Delaware County previously had been declared to be impaired due to excess nutrient phosphorus; however, its status was improved by active water quality remedial management efforts, including wastewater treatment plant upgrades, septic system repairs and replacements, construction of stormwater retrofits, and installation of best management practices on several hundred farms located throughout the Catskill and Delaware Watershed, most notably in Delaware County. As a result of this comprehensive and aggressive watershed protection program, the Department has determined that the Cannonsville Reservoir has been returned to regulatory compliance. The two reservoirs located in the Catskill portion of the NYC Watershed have been determined by the Department to be impaired due to excessive levels of suspended sediment (Ashokan and Schoharie Reservoirs).

The most recent EPA Filtration Avoidance Determination (FAD) was granted to NYC by EPA, in consultation with NYSDOH, in 2007 for the unfiltered use of the Catskill and Delaware systems and interconnected reservoir basins located in watershed communities to the east of the Hudson River. Waters flowing from the Croton portion of the NYC Watershed have been required to be filtered by EPA (at a cost of approximately $3 billion for construction of the filtration plant). Systems of aqueducts and interchanges, however, allow for Croton waters to be transferred and intermixed with waters from the Catskill and Delaware systems to assure an adequate water supply in stressed or emergency situations, such as significant drought or major infrastructure failure.

The City of Syracuse, with a population of approximately 145,000, has also been granted permission by EPA and NYSDOH to operate an unfiltered drinking water supply. The most recent filtration avoidance determination was issued by NYSDOH to Syracuse in 2004. The unfiltered source water is Skaneateles Lake, a Finger Lake that is located approximately 20 miles to the south and west of Syracuse. The Skaneateles Lake watershed comprises a total area of 59 square miles that includes the lake - which is approximately 14 miles long and 1 mile wide. Reports issued by the Syracuse Department of Water state that Skaneateles Lake generally provides between 32 and 34 million gallons of potable water daily. The most recent NYSDOH source water assessment found that Skaneateles Lake had a moderate susceptibility to contamination, including a level of farm pasture land that results in a high potential for protozoan contamination. Copper sulfate treatments are at times administered to Skaneateles Lake to control phosphorus-induced algae growth and associated adverse impacts such as poor taste and odor.

6.1.5.1 Pollutants of Critical Concern in Unfiltered Drinking Water Supplies

One of the fundamental concepts framing the effective protection of unfiltered drinking water is "source water protection." Management programs in such watershed necessarily focus on systematically preventing contaminants from reaching the waters in the first instance, as there is no mechanism in place (such as a filtration plant) to remove contaminants once they have entered the water. Once polluted, it very difficult and very expensive to return these water supplies back to their original condition. In both the NYC and City of Syracuse watersheds, extensive efforts have been undertaken to stringently treat sewage discharges. Within the Skaneateles Lake watershed, any discharge, whether treated sewage effluent or otherwise, to any surface water is prohibited. Within the NYC Watershed, all sewage treatment plants must achieve an extraordinarily stringent level of treatment consistent with "tertiary treatment, micro-filtration and biological phosphorus removal." These are the most technologically advanced sewage treatment plants in New York State. Therefore, the critical remaining potential for impairment of these two unfiltered water supplies stems from human activities that place contaminants on the ground that can then be washed into reservoirs and tributaries via storm water runoff, or flow into them from contaminated groundwater.

The National Research Council of the National Academies of Sciences undertook a detailed assessment of the risks and sensitivities associated with the NYC Watershed and water supply system. This peer-reviewed report provides useful background on the distinctive nature of risks resulting from potential surface pollution in unfiltered drinking water watersheds and supplies.[297] The concerns and management methods discussed in this report are also relevant and applicable to the City of Syracuse drinking water supply.

In general, the pollutants of key concern when managing an unfiltered drinking water system are: (i) nutrient phosphorus; (ii) microbial pathogens; (iii) suspended sediment (or "turbidity"); and

[297] National Research Council, 2000.

(iv) toxic compounds. As explained below, the adverse impacts of these contaminants are substantially heightened in unfiltered drinking water systems.

Phosphorus: Excess phosphorus leads to algae blooms, including increased growth of toxin emitting blue-green algae. Algae blooms lead to high bacteria growth (due to bacterial consumption of algae) that, in turn, deplete the reservoir bottom waters of dissolved oxygen. Low dissolved oxygen suffocates or drives off fish. Low oxygen levels cause a change in the biology of reservoir waters (to anaerobic conditions) that result in impaired water taste, odor, and color. For example, iron, manganese and H_2S are brought into the water column under these low oxygen conditions. The higher levels of dead algae, bacteria and other chemicals in the water constitute an increase in organic matter that can react with chlorine during the drinking water disinfection process - causing elevated levels of "disinfection by-products"; many of these chlorinated organic compounds are suspected by the EPA of being carcinogens and have been identified in a number of medical studies as a factor linked to early term miscarriage. Finally, the increased material suspended in water, which results from phosphorus-induced algae blooms, can interfere with the effectiveness of chlorination and ultraviolet light irradiation on pathogens, and thereby foster the transport waterborne pathogens to water consumers.

Phosphorus is a naturally-occurring element that is found in human and animal wastes, animal and plant materials, fertilizers and eroded soil particles. While essential for life, excess phosphorus at very low levels can cause the adverse environmental and public health impacts discussed above during the warm weather growing season. Guidance value concentrations, set by the Department to limit adverse impacts from phosphorus in NYC Watershed reservoirs, range between 15 and 20 parts per billion (ppb).

Microbial Pathogens: A surface drinking water source may be adversely impacted by a range of disease-causing microorganisms such as bacteria, viruses and protozoa. Such organisms can result from a variety of sources but to a significant extent result from human and animal wastes or possible re-growth in bio-slimes that may form within a drinking water supply system. Both the NYC and Syracuse drinking water supplies are required by EPA and NYSDOH regulations to employ two forms of disinfection in series that, when combined with effective source water protection programs, are highly effective in destroying or de-activating bacteria, viruses and protozoa.

However, there are two disinfection-resistant protozoa that have emerged in recent decades that can cause significant intestinal illness in otherwise healthy humans, and result in severe illness and even death in individuals with compromised immune systems. These protozoa, *Giardia lamblia* and *Cryptosporidium parvum*, both have life stages where they form cysts (or oocysts) that can survive standard disinfection treatments and infect human hosts. The basic public health management response to such organisms is to limit specific human and animal waste transmission pathways to waters on the landscape and to require controls that limit such occurrences as algae blooms and suspended sediments, which can assist in the transmittal of pathogens. As discussed below, inadequately effective controls will likely result in the imposition of a costly filtration requirement by EPA or NYSDOH in accordance with the SDWA and the underlying SWTR.

Sediment or Turbidity: Sediment laden, or turbid, water can increase the effective transportation of pathogens, serve as food for pathogens, promote the re-growth of pathogens in the water distribution system, and shelter pathogens from exposure to attack by disinfectants such as chlorine or ultraviolet light. The organic particles that are a cause of turbidity can combine with chlorine to create problematic disinfection by-products that are possible carcinogens and suspected by medical studies of increasing the risk of miscarriage.

EPA, in its SWTR, prohibits raw water turbidity measurements in unfiltered drinking water at the intake to the distribution system in excess of 5 nephelometric turbidity units (essentially, very clear water).[298] More than one violation per year is grounds for EPA or NYSDOH to require construction of a water filtration plant. Such a plant for the Catskill and Delaware portions of the NYC water supply has been estimated to cost between $8 to $10 billion with an additional $200 (plus) million a year in operational and maintenance expenses. An overview of the public health concerns raised by turbidity in drinking water are discussed in greater detail at: *U.S. EPA, Guidance Manual for Compliance with the Interim Enhanced Surface Water Treatment Rule: Turbidity Provisions*, Office of Water, EPA 815-R-99-010, April 1999, Chapter 7 (and numerous cited references); *see* also Kistemann, T., *et al.*, *Microbial Load of Drinking Water Reservoir Tributaries During Extreme Rainfall and Runoff*, Applied Environmental Microbiology, Vol. 68, No. 5, pp. 2188-2197 (May 2002); Naumova, E., *et al.*, *The Elderly and Waterborne*

[298] 40 CFR §141.71(a)(2).

Cryptosporidium Infection: Gastroenteritis Hospitalizations Before and During the 1993 Milwaukee Outbreak, Emerging Infectious Diseases, Vol. 9 No. 4, pp. 418-425 (2003).

Toxic Compounds: Unfiltered drinking water supplies have a heightened sensitivity to chemical discharges as there is no immediately available method to remove contaminants from the drinking water source waters. Well pad containment practices and setbacks are likely to effectively contain most spills at those locations. There is a continuing risk, however, of releases from chemicals, petroleum products and drilling fluids from the well pad 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. The intensive level of trucking activity associated with high-volume hydraulic fracturing, including the transport of chemical and petroleum products, presents an additional risk of surface water contamination due to truck accidents and associated releases. Given the topography of much of the NYC and Skaneateles Lake watersheds, many of the roadways are in immediate proximity to tributaries. Such proximity increases the risk that chemical and petroleum spills would not, or could not, be effectively intercepted before entering the drinking water supply.

6.1.5.2 Regulatory and Programmatic Framework for Filtration Avoidance

The basic statutory and regulatory framework applicable to unfiltered drinking water supplies is provided by the federal Safe Drinking Water Act (SDWA), 42 U.S.C. sec. 300f, et al. The SDWA directed EPA to adopt regulations requiring public water supplies using surface waters to apply filtration systems to treat their water unless protective "criteria" or "standards" could be met. Pursuant to this grant of authority, EPA issued the SWTR, 40 CFR sec. 141.71, et al. Subject to continuing oversight, EPA has delegated authority to administer the SDWA within New York to the NYSDOH pursuant to State statutory and regulatory authority that is consistent with the federal protocol.

There are numerous "filtration avoidance criteria" specified in the SWTR. These criteria must be met for a drinking water supply system to maintain its unfiltered status. The first two criteria address fecal coliform and turbidity limits in raw water before disinfection. The next four criteria address assuring the effectiveness of disinfection and the maintenance of sufficient levels of disinfection agents in the water distribution system. The next five criteria variously address landscape control programs for *Giardia lamblia,* water supply system inspections, prohibition on waterborne disease outbreaks, and maximum contaminant level compliance for total coliform and disinfection by-products in drinking water after disinfection.

Another key provision operates to drive overarching watershed planning and protection programs, along with cooperative agreements with individuals and municipalities situated within the unfiltered watershed: "The public water system must demonstrate through ownership and/or written agreements with landowners within the watershed that it can control *all human activities which may have an adverse impact on the microbiological quality of the source water*." 40 CFR sec. 141.71(b)(2)(iii) (emphasis added). High-volume hydraulic fracturing and associated activities are within the scope of "human activities" covered by this regulatory provision. As discussed above, human activities that increase levels of phosphorus and sediment, or heighten storm water flows that could transmit microbial pathogens into waters, would all have an "impact on the microbiological quality of the source water."

Major efforts have been undertaken to cooperatively assure equitable implementation of programs to protect the NYC Watershed and water supply. In 1997, essentially all stakeholders associated with the NYC Watershed entered into the "1997 New York City Watershed Memorandum of Agreement." This binding three volume agreement specified extensive programs with respect to land acquisition, extra-territorial regulations promulgated by NYC, the establishment of a Watershed Protection and Partnership Council, and an array of specific programs to limit pollution from septic systems, construction excavations, salt storage facilities, runoff from impervious surfaces, timber harvesting, waste water treatment plants, unstable streams and farms. An extensive and updated source water protection program also is detailed in the FAD that was issued to NYC (covering environmental infrastructure, protection and remedial water quality efforts, watershed monitoring and regulatory implementation). Protection programs, as well as programs to equitably address the concerns of local residents, were also detailed in a Department Water Supply Permit that was finalized and issued to NYC in January 2011. It is estimated that at least $1.6 billion has been invested in NYC Watershed protection programs since 1997.

Syracuse has developed similar programs to prevent contamination of Skaneateles Lake and its watershed. Specific regulations have been developed to address a range of human activities that could adversely impact water quality – including sewage treatment plants, septic systems, and erosion and sediment controls at construction sites. Syracuse implements a "Watershed Agricultural Program" to cooperatively limit pollution that could result from crop land and animal agricultural activities. A program of conservation easements in certain sensitive lands has also been developed to limit human activity that might harm water quality.

6.1.5.3 Adverse Impacts to Unfiltered Drinking Waters from High-Volume Hydraulic Fracturing

Activities associated with high-volume hydraulic fracturing involve a significant amount of land clearing and excavation. New roads, sufficient to reach the well pad and of a design capable of handling a high volume of fully loaded truck traffic, would need to be cleared and cut. The often steep terrain of the NYC and Skaneateles Lake watersheds would necessitate a significant level of cut and fill roadway excavations, as well as soil stockpiles, that would expose soils to erosive activities. The excavation and grading of level well pads (generally ranging from 3 to 5 acres in size) to support drilling activities would create significant additional amounts of exposed soils and cut and fill excavations. Gas transmission pipelines of various sizes would necessarily be cut through the watersheds, often in straight lines and down hills in a manner that can accelerate and channelize water during precipitation events. Both the NYC Watershed and Skaneateles Lake watershed regularly receive high precipitation events that operate to mobilize exposed soil particles.

The clearing of vegetation, and the excavation and compaction of soils, associated with new roads, pipelines and drilling well pads in the NYC and Skaneateles Lake watersheds also will increase the volume and intensity of stormwater runoff, even if subject to stormwater control. While not fully "impervious" this less pervious landscape will increase runoff. Moreover, to support high volumes of truck traffic, narrow existing dirt roads may need to be paved and widened, as has been the experience in Pennsylvania. One acre of impervious surface is estimated to create the same amount of runoff as 16 acres of naturally vegetated meadow or forest.[299] Therefore, new impervious surfaces (as well as the substantially less-pervious surfaces created by the removal of vegetation and compaction of soils associated with construction excavations) can transmit very high volumes of stormwater relative to natural conditions that then operate to destabilize road-side ditches and streams, and cause additional erosion. As

[299] Schuler, 1994, p. 100.

discussed, elevated turbidity or suspended sediment levels present particular public health concerns in an unfiltered drinking water supply, a problem that already significantly affects the Catskill portion of the NYC Watershed, including the Schoharie and Ashokan Reservoirs.

As in other areas of the state, erosion and sediment control measures would significantly limit the adverse impacts of stormwater flow from construction excavations, erosion, soils compaction and increased imperviousness associated with high-volume hydraulic fracturing. However, even with such stormwater controls, the heightened sensitivity of these unfiltered watersheds make the potential for adverse impacts to water quality from sedimentation due to construction excavations significant during levels of projected peak activity. Even with state-of-the art stormwater controls a risk of increased stormwater runoff from accidents or other unplanned events cannot be entirely eliminated. The potential consequences of such events – loss of the FAD – is significant even if the risk of such events occurring is relatively small. Similarly, the risks associated with high volumes of truck traffic transporting chemical and petroleum products associated with high-volume hydraulic fracturing is inconsistent with effective protection of an unfiltered drinking water supply. This is especially so, as a number of factors, discussed above, are already operating to stress the NYC and Syracuse source waters. This concern is exemplified by an extensive study by researchers from SUNY ESF and Yale published in 2008. This peer-reviewed report concluded that the current rate of excavations and associated increases in impervious and less pervious surfaces within the NYC Watershed would likely result in the phosphorus impairment of all reservoirs over an approximate 20 year time frame. Hall, M., R. Germain, M. Tyrell, and N. Sampson, P*redicting Future Water Quality from Land Use Change Projections in the Catskill-Delaware Watersheds,* pp. 217-268 (2008) (available at http://www.esf.edu/es/faculty/hall.asp). This report does not take into consideration the accelerated development associated with high-volume hydraulic fracturing.

6.1.5.4 Conclusion

The Department finds that high-volume hydraulic fracturing activity is not consistent with the preservation of the NYC and Syracuse watersheds as unfiltered drinking water supplies. Even with all of the criteria and conditions identified in the revised draft SGEIS, a risk remains that significant high-volume hydraulic fracturing activities in these areas could result in a degradation of drinking water supplies from accidents, surface spills, etc. Moreover, such large scale industrial activity in these areas, even without spills, could imperil EPA's FADs and result in the affected municipalities incurring substantial costs to filter their drinking water supply.

Accordingly, and for all of the aforementioned reasons, the Department concludes that high-volume hydraulic fracturing operations within the NYC and Syracuse watersheds pose the risk of causing significant adverse impacts to water resources. As discussed in Chapter 7, standard mitigation measures such as stormwater controls would only partially mitigate such impacts. Such partial mitigation is unacceptable due to the potential consequences – adverse impacts to human health and loss of filtration avoidance – posed by such impacts.

6.1.6 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 as a result of an improperly constructed well; 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 8.4.5, 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.[300]

[300] ICF Task 1, 2009,

6.1.6.1 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). Hydraulic fracturing is not known to cause wellbore failure in properly constructed wells.

6.1.6.2 Subsurface Pathways

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 under hypothetical assumptions of a hydraulic connection. Appendix 11 provides ICF's full discussion of the principles governing potential fracture fluid flow under this hypothetical condition. ICF's conclusion is that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers." [301] 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; and
- 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.

[301] ICF Task 1, 2009, p. 34

As noted in Section 2.3.6, 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 Environmental, under its contract with NYSERDA, provided the following additional information regarding the Marcellus and Utica Shales:[302]

> The Marcellus and Utica Shales dip southward from the respective outcrops of each member, and most of the extents 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.

Natural Controls on Underground Fluid Migration

As noted by ICF (Subpart 5.11.1.1 and Appendix 11) and Alpha (as cited above) , 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. Figure 4.2 shows that most of the bedrock formations above the Marcellus Shale are other shales. That shales must be hydraulically fractured to produce fluids is evidence that these rocks do not readily transmit fluids. The high salinity of native water in the Marcellus and other Devonian shales is evidence that fluid has been trapped in the pore spaces for a significant length of time, implying that there is no mechanism for discharge.

As previously discussed, hydraulic fracturing is engineered to target the prospective hydrocarbon-producing zone. The induced fractures create a pathway to the intended wellbore, but do not create a discharge mechanism or pathway beyond the fractured zone where none existed before. The pressure differential that pushes fracturing fluid into the formation is diminished once the rock has fractured, and is reversed toward the wellbore during the flowback and production phases.

[302] Alpha, 2009, p. 3-3.

Darcy's Law is a universally accepted scientific principle of hydrogeology. It states the relationship that explains fluid flow in porous media. Flow rate, Q, is calculated by

$$Q=KA(P_{high}-P_{low})/\mu L$$

where K= permeability, A= cross sectional area, P=pressure, μ=fluid viscosity and L=length of flow. The factor "P_{high}-P_{low}" describes a pressure differential, and Darcy's Law explains the relationship between pressure and fluid flow. During hydraulic fracturing operations, the pressure in the well is greater than the pressure in the formation and drives the fluid and sand into the rock creating the induced fractures. If induced fractures do intersect an open fault or wellbore that diverts fluid from the target formation during pumping, this would be detected by required pressure monitoring during the fracturing process. Permit conditions will require pumping operations to cease if this occurs, until the anomalous condition is evaluated and addressed. Cessation of pumping will remove the pressure differential and stop further flow away from the target formation. Additionally, the force exerted by lithostatic pressure (i.e., the weight of overlying rocks) tends to close natural fissures at depth, so even when such fissures exist they are not necessarily transmissive. This is the reason that hydraulic fracturing requires the use of proppant to keep induced fractures open to transmit natural gas to the wellbore. Also, even if it is assumed that fractures in overlying strata are transmissive, there is no reason to believe that the fractures of different strata are aligned in a manner that would make hydraulic connections possible.

Once pumping ceases and hydraulic fracturing is accomplished, the well is turned into the production system at the surface which is at a much lower pressure than the formation. Therefore gas flows to the well and the surface. At this point there is no pressure differential that would cause fluid to move in any direction other than towards the gas well.

All of the above factors that inhibit vertical fracturing fluid migration would also inhibit horizontal migration beyond the fracture zone for the distances required to impact potable water wells in the Marcellus and other shales from high-volume hydraulic fracturing under the conditions specified by ICF. Because of regional dip, the geographic location of any target reservoir where it is more than 1,000 feet below the presumed base of fresh water would be at least several miles south of any location where water wells are completed in the same rock formation.

Mapped Marcellus Hydraulic Fracturing Stages

Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas.[303] Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.

6.1.7 Waste Transport

Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and production brine are classified as non-hazardous industrial-commercial waste which would be hauled under a New York State Part 364 waste transporter permit issued by the Department. All Part 364 transporters would identify the general category of wastes transported and obtain written authorization from each destination facility, which must be maintained at the place of business and made available to the Department upon request.

Manifesting is not required for non-hazardous industrial-commercial waste, so there is no tracking and verification of disposal destination on an individual load basis. Although the Department's regulations do not classify drilling and production wastes as hazardous, like all wastes they must be handled and disposed of in accordance with all applicable regulatory requirements. One concern is that wastes will not be properly identified or may not be taken to appropriate, permitted facilities. Chapter 7 provides mitigation for this concern in the form of a waste tracking procedure similar to that which is required for medical waste even though the hazards are not equivalent. Another concern relates to potential spills as a result of trucking accidents. It should be noted that the developing practice of treating and reusing flowback water on the same well pad would reduce the number of truck trips for hauling flowback water to other

[303] Fisher, 2010, pp. 30-33.

destinations. Information about traffic management related to high-volume hydraulic fracturing is presented in Section 7.8.

6.1.8 Fluid Discharges

Direct discharge of fluids onto the ground or into surface water bodies from the well pad are prohibited. Discharges would be managed at treatment facilities, appropriately recycled, or in permitted disposal wells.

6.1.8.1 POTWs

Surface water discharges from water treatment facilities are regulated under the Department's SPDES program. Acceptance by a POTW 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.

Flowback water may be sent to POTWs. However, treatability of flowback water presents a potential environmental concern because 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. Table 6.1 provides information on flowback water composition based on a limited number of samples from Pennsylvania and West Virginia.

Appendix 21 is a list of POTWs with approved pretreatment and mini-pretreatment programs. Note that this is not a list of facilities approved to accept wastewater from high-volume hydraulic fracturing. Rather, it is a list of facilities that have SPDES permit conditions and requirements allowing them to accept wastewater from hauled or other significant industrial sources in accordance with 40CFR Part 403. To accept a source of wastewater, the facility must first evaluate the pollutants present in that source of wastewater against an analysis of the capabilities of the individual treatment units and the treatment system as a whole to treat these pollutants; that analysis is known as a Maximum Allowable Headworks Loading analysis (MAHW, or headworks analysis). 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 ECL 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 concentrations of TDS that exist in both flowback water and production brine, requires that the permittee submit a headworks analysis specific to the parameters expected present in high-volume hydraulic fracturing wastewater, including TDS and NORM, to both the Department and EPA Region 2 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 Department 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 and EPA 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 production brine, the permittee may assess the impacts of the proposed discharge against the existing headworks analysis.

The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production brine prior to the issuance of the drilling permit. Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.

Flowback water and production brine must be fully characterized prior to acceptance by a POTW for treatment. Note in particular Appendix C. IV of TOGS 1.3.8, *Maximum Allowable Headworks Loading*. The POTW must perform a MAHW analysis to assure that the flowback water and production 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 influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge. In the case of NORM, anyone proposing to discharge flowback water or production brine to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge. For example, due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7. As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited.

Specific information regarding high volume hydraulic fracturing additives, such as chemical makeup and aquatic toxicity, will be required for this analysis. A complete listing of all ingredients in each chemical additive to be used shall be included as part of a headworks analysis, along with aquatic toxicity data for each of the additives. 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 production brine from wells permitted pursuant to this Supplement.

In conducting the headworks analysis, the parameters that must be analyzed include, at a minimum:

- pH, range, SU;
- Oil and Grease;
- Solids, Total Suspended;
- Solids, Total Dissolved;
- Chloride;
- Sulfate;
- Alkalinity, Total ($CaCO_3$);
- BOD, 5 day;
- Chemical Oxygen Demand (COD);
- Total Kjeldahl Nitrogen (TKN);
- Ammonia, as N;
- Total Organic Carbon;
- Phenols, Total;
- the following scans:
  - Priority Pollutants Metals;
  - Priority Pollutants VOC;
  - Priority Pollutants SVOC Base/Neutral; and
  - Priority Pollutants SVOC Acid Extractable;
- Radiological analysis 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;and
- Thorium - EPA Method 910, Standard Methods 7500-Th;

- constituents that were present in the hydraulic fracturing additives.

The high concentrations of TDS present in this source of wastewater may prove to be inhibitory to biological wastewater treatment systems. It has been noted that the concentrations of TDS in the return and process water increase as a higher percentage of native water is produced and then stabilize 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.

The Department has performed a very basic analysis to determine the potential available capacity for POTWs to accept high-volume hydraulic fracturing wastewater. The Department estimates that the POTWs within the approximate area of shale development in New York have an aggregate available flow capacity of approximately 300 MGD, which is the difference between existing flow and permitted flow. Based on this capacity, an estimate was developed to determine the existing total treatment capacity based on the actual flows, existing TDS levels and allowable TDS discharge limits. This estimate was based on a conservative assumption of influent TDS from production brine. This estimate assumes that all of these POTWs would be willing to accept this wastewater to their maximum available capacity, and that no other increased discharges or other growth in the service area are expected. A TDS level of 350,000 mg/L will be used, as this is on the upper end of expected concentrations. Discharge levels from POTWs would be limited to 1,000 mg/L. Typical influent levels of TDS at a POTW are approximately 300 mg/L. Therefore, a typical POTW can be expected to have a disposal capacity of approximately 700 mg/L (1,000 – 300mg/L) of TDS. Again assuming an influent level of 350,000 mg/L of TDS and a disposal capacity of 700 mg/L at an existing POTW, the dilution ratio of existing POTW flow to allowable high-volume hydraulic fracturing wastewater influent flow is 500:1 (350,000 divided by 700). Based on this analysis, the maximum total capacity for disposal of high-volume hydraulic fracturing wastewater is estimated to be less than 1 MGD. The estimated production brine per well may range from 400 gpd to 3,400 gpd depending on the life of the well.

The above analysis is subject to a number of assumptions which, when actual conditions are factored in, will limit the available capacity to much less than 1 MGD. The analysis assumes that the treatment facilities are willing to accept this source of wastewater; following its December 2008 letter to POTWs outlining the requirements to accept high-volume hydraulic fracturing wastewater, the Division of Water has yet to receive any requests from any POTW in the State to accept this source of wastewater. The analysis assumes that POTWs are equipped to take this source of wastewater and that haulers are willing to pump the waste into the POTW at the rate that will be required to protect the POTW; no POTWs in New York State currently have TDS-specific treatment technologies, so the ability to accept this wastewater is limited by influent concentration and flow rates. The analysis assumes that the receiving water has assimilative capacity to accept additional TDS loadings from POTWs and that the background TDS in the receiving water is less than the in-stream water quality standard of 500 mg/L; there are several streams in New York State which cannot accept additional TDS loads. Based on the above, there is questionable available capacity for POTWs in New York State to accept high-volume hydraulic fracturing wastewater.

Case Study: One wellpad is expected to have 8 wells. Each well is expected to produce 3,000 gallons of production brine. Assuming 3,000 gpd x 8 wells = 24,000 gpd. With a 500:1 ratio needed for disposal, a POTW with an existing flow of 12 mgd would be needed to dispose of the production brine from this single wellpad.

Further, because of the inability of biological treatment systems to remove certain high-volume hydraulic fracturing additives in flowback water, as previously described, POTWs are not usually equipped to accept influent containing these contaminants. The potential for inhibition of biological activity and sludge settling and the potential for radionuclide concentration in the sludge impacts sludge disposal options.

As noted previously, acceptance of wastewater from high-volume hydraulic fracturing operations must consider the impacts to POTW operation, sludge disposal, effluent quality, and POTW health and safety. Concentrations of NORM, specifically radium, in natural gas drilling wastewater have the potential to impact POTW sludge disposal. At this time there is a lack of detailed information on levels of NORM in POTW sludge and to what extent NORM that is introduced to a POTW is concentrated in the sludge. Therefore, to ensure that POTW sludge disposal is not affected, an influent radium-226 limit of 15 pCi/L for high-volume hydraulic fracturing wastewater, to be determined prior to admixture with other POTW influents, would be required in SPDES permits for any POTW that proposes to accept high-volume hydraulic fracturing wastewater. It is noted that there are a number of water bodies in NY where the ambient levels of TDS already exceed the water quality standard or where TDS has already been fully allocated in existing SPDES permits. This may further limit the ability of POTWs to accept these discharges.

6.1.8.2 Private Off-site Wastewater Treatment and/or Reuse Facilities

Privately owned facilities built specifically for the reuse and/or 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 if the operator of the facility intends to discharge treated effluent to surface or groundwater. The treatment methods that would be applicable to these facilities are discussed in Chapter 5. A number of adverse impacts are possible resulting from improper maintenance or overloading of these systems, resulting in either surface or water discharges that do not comply with applicable standards. However, properly maintained and regulated systems, along with waste tracking and SPDES permitting control measures as described in Chapter 7 would mitigate the potential for these impacts. The same limitations and impacts noted regarding the effects of discharges from POTWs to the waters of the State, including the ability of the receiving water to accept additional TDS loads, as described in Section 6.1.8.1 above, also apply to privately-owned off-site treatment works.

6.1.8.3 Private On-site Wastewater Treatment and/or Reuse Facilities

As noted in Chapter 5 of this Draft SGEIS, on-site treatment of flowback water for purposes of reuse is currently being used in Pennsylvania and other states. The treated water is blended with fresh water at the well site and reused for hydraulic fracturing, with the treatment system residue hauled off-site. A number of adverse impacts are possible resulting from improper maintenance or overloading of these systems, resulting in either surface or water discharges that do not comply with applicable standards. However, properly maintained and operated treatment and/or reuse systems, along with the waste tracking measures described in Chapter 7, would mitigate the potential for these impacts. Because all applicable technology-based requirements must be applied in NPDES/SPDES permits under the Clean Water Act section 402(a) and implementing regulations at 40 CFR 125.3, an NPDES/SPDES permit issued for drilling activity would need to be consistent with 40 CFR Part 435, Subpart C, which states that “there shall be no discharge of wastewater pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e. production brine, drilling muds, drill cuttings, and produced sand.”

6.1.8.4 Disposal Wells

As stated in the 1992 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 would 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.

6.1.8.5 Other Means of Wastewater Disposal

Wastewater generated by high-volume hydraulic fracturing would be able to be treated and disposed of to the extent that available capacity exists using the disposal options referenced in Section 6.1.8.4 above. Should wastewater be generated in volumes exceeding available capacity within the State, the wastewater would require transport and disposal at facilities not located in New York State, or additional treatment facilities to be constructed. Potential impacts that may result from insufficient wastewater treatment capacity would include either storage of wastewater and associated potential for leaks or spillage, illegal discharge of wastewater to the ground surface or directly to waters of the State, and increased truck traffic resulting from transport of wastewater to out of state treatment and disposal facilities.

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 1992 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 NORM Considerations - Cuttings

Gamma ray logs from deep wells drilled in New York over the past several decades show the Marcellus Shale to be higher in radioactivity than other bedrock formations including other potential reservoirs that could be developed by high-volume hydraulic fracturing. However, 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 because – as set forth in Section 5.2.4.2 – the levels are similar to those naturally encountered in the surrounding environment.

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 about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system. The geotechnical stability and bearing capacity of buried cuttings, if left in a common pit, may need to be reviewed prior to pit closure.[304]

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.

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

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, production 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."[305] Accordingly, construction of drill pads within flood plains raises serious and significant environmental issues and risks.

6.3 Freshwater Wetlands

State regulation of wetlands is described in Chapter 2. The 1992 GEIS summarizes the potential impacts to wetlands associated with interruption of natural drainage, flooding, erosion and sedimentation, brush disposal, increased access and pit location, and those potential impacts are applicable to high-volume hydraulic fracturing. 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, also extend to wetlands.

6.4 Ecosystems and Wildlife

The 1992 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). Significant habitats are defined as areas that 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. This section considers the potential impact of high-volume hydraulic fracturing on all terrestrial habitat types, including forests, grasslands (including old fields managed for grasslands, and pasture and hay fields) and shrublands. Four areas of concern related to high-volume hydraulic fracturing are:

1) fragmentation of habitat;

[305] NYSDEC, 1992, GEIS, p. 8-44

2) potential transfer of invasive species;

3) potential impacts on endangered and threatened species; and

4) use of certain State-owned lands.

When the 1992 GEIS was developed, the scale and scope of the anticipated impact of oil and gas drilling in New York State was much different than it is today. Development of low-permeability reservoirs by high-volume hydraulic fracturing have the potential to draw substantial development into New York, which is reasonably anticipated to result in potential impacts to habitats (fragmentation, loss of connectivity, degradation, etc.), species distributions and populations, and overall natural resource biodiversity.

The development of Marcellus Shale gas will have a large footprint.[306] In addition to direct loss of habitat, constant activity on each well pad from construction, drilling, and waste removal can be expected for 4 to 10 months, further affecting species. If a pad has multiple wells, it might be active for several years. More land is disturbed for multi-well pads, but fewer access roads, infrastructure, and total pads would be needed. Well pad sites are partially restored after drilling, but 1-3 acres is typically left open for the life of the well (as are access roads and pipelines), which is expected to be 20 to 40 years.

6.4.1 Impacts of Fragmentation to Terrestrial Habitats and Wildlife

Fragmentation is an alteration of habitats resulting in changes in area, configuration, or spatial patterns from a previous state of greater continuity, and usually includes the following:

[306] Environmental Law Clinic, 2010.

- Reduction in the total area of the habitat;
- Decrease of the interior to edge ratio;
- Isolation of one habitat fragment from other areas of habitat;
- Breaking up of one patch of habitat into several smaller patches; and
- Decrease in the average size of each patch of habitat.

General Direct, Indirect, and Cumulative Impacts:

Habitat loss, conversion, and fragmentation (both short-term and long-term) would result from land grading and clearing, and the construction of well pads, roads, pipelines, and other infrastructure associated with gas drilling.[307]

Habitat loss is the direct conversion of surface area to uses not compatible with the needs of wildlife, and can be measured by calculating the physical dimensions of well pads, roads, and other infrastructure. In addition to loss of habitat, other potential direct impacts on wildlife from drilling in the Marcellus Shale include increased mortality, increase of edge habitats, altered microclimates, and increased traffic, noise, lighting, and well flares. Existing regulation of wellhead and compressor station noise levels is designed to protect human noise receptors. Little definitive work has been done on the effects of noise on wildlife.[308]

Habitat degradation is the diminishment of habitat value or functionality; its indirect and cumulative effects on wildlife are often assessed through analysis of landscape metrics. Indirect and cumulative impacts may include a loss of genetic diversity, species isolation, population declines in species that are sensitive to human noise and activity or dependent on large blocks of habitat, increased predation, and an increase of invasive species. Certain life-history characteristics, including typically long life spans, slow reproductive rates, and specific habitat requirements for nesting and foraging, make raptor (birds of prey) populations especially vulnerable to disturbances. Direct habitat loss has less impact than habitat degradation through

[307] Environmental Law Clinic, 2010.

[308] New Mexico Dept. Game & Fish, 2007.

fragmentation and loss of connectivity due to widespread activities like oil and gas development.[309]

Biological systems are exceedingly complex, and there can be serious cascading ecological consequences when these systems are disturbed. Little baseline data are available with which comparisons can later be made in the attempt to document changes, or lack thereof, due to oil and gas development. In cases where serious adverse consequences may reasonably be expected, it is prudent to err on the side of caution.[310]

Habitat fragmentation from human infrastructure has been identified as one of the greatest threats to biological diversity. Research on habitat fragmentation impacts from oil and gas development specific to New York is lacking. However, the two following studies from the western United States are presented here to illustrate qualitatively the potential impacts to terrestrial habitats that could occur in New York. A quantitative comparison between these studies and potential impacts in New York is not possible because these studies were conducted under a regulatory structure that resulted in well spacing that differs from those anticipated for high-volume hydraulic fracturing in New York. Additional research would be necessary to determine the precise impacts to species and wildlife expected from such drilling in New York's Marcellus Shale.

While fragmentation of all habitats is of conservation concern, the fragmentation of grasslands and interior forest habitats are of utmost concern in New York. Some of the bird species that depend on these habitat types are declining. This decline is particularly dramatic for grasslands where 68% of the grassland-dependent birds in New York are declining.[311]

Projected Direct Impacts

Study 1, General Discussion: The Wilderness Society conducted a study in 2008[312] that provided both an analytical framework for examining habitat fragmentation and results from a hypothetical GIS analysis simulating the incremental development of an oil and gas field to

[309] New Mexico Dept. Game & Fish, 2007.

[310] New Mexico Dept. Game & Fish, 2007.

[311] Post 2006.

[312] Wilbert et al., 2008.

progressively higher well pad numbers over time. Results of the sample analysis gave a preliminary estimate of the minimum potential fragmentation impacts of oil and gas development on wildlife and their habitats; the results were not intended to be a substitute for site-specific analyses.

The study identified a method to measure fragmentation (landscape metrics), and a way to tie various degrees of fragmentation to their impacts on wildlife (from literature). Two fragmentation indicator values (road density and distance-to-nearest-road or well pad) were analyzed for impacts to a few important wildlife species present in oil and gas development areas across the western U.S.

Study 1, Findings: The total area of direct disturbance from well pads and roads used in oil and gas development was identified for a hypothetical undeveloped 120-acre site, with seven separate well-pad densities - one pad per 640 acres, 320 acres, 160 acres, 80 acres, 40 acres, 20 acres, and 10 acres:

1. Well pads: the disturbance area increased approximately linearly as pad density increased;

2. Total road length: the disturbance area increased more rapidly in the early stages of development;

3. Mean road density: the rate of increase was higher at earlier stages of development. The size of the pre-development road system had an effect on the magnitude of change between subsequent development stages, but the effect decreased as development density increased;

4. Distance-to-nearest-road (or well pad): the rate of decrease was higher at earlier stages of development than at later stages; and

5. Significant negative effects on wildlife were predicted to occur over a substantial portion of a landscape, even at the lower well pad densities characteristic of the early stages of development in gas or oil fields.

This suggests that landscape-level planning for infrastructure development and analysis of wildlife impacts need to be done prior to initial development of a field. Where development has already occurred, the study authors recommend that existing impacts on local wildlife species be measured and acknowledged, and the cumulative impacts from additional development be assessed.

Study 1, Implications for New York: The study results emphasize the importance of maintaining undeveloped areas. Note that the degree of habitat fragmentation and the associated impacts on wildlife from such development in real landscapes would be even greater than those found in the study, which used conservative estimates of road networks (no closed loops, shorter roads, and few roads pre-development) and did not include pipelines and other infrastructure.

Projected Indirect and Cumulative Impacts

Study 2, General Discussion: The Wilderness Society conducted a study in 2002[313] that analyzed the landscape of an existing gas and oil field in Wyoming to identify habitat fragmentation impacts. As fragmentation of the habitat occurred over a wide area, cumulative and indirect impacts could not be adequately addressed at the individual well pad site level. Rather, analyzing the overall ecological impacts of fragmentation on the composition, structure, and function of the landscape required a GIS spatial analysis. A variety of metrics were developed to measure the condition of the landscape and its level of fragmentation, including: density of roads and linear features; acreage of habitat in close proximity to infrastructure; and acreage of continuous uniform blocks of habitat or core areas.

Study 2, Findings: The study area covered 166 square miles, and contained 1864 wells, equaling a density of 11 wells per square mile.[314] The direct physical footprint of oil and gas infrastructure was only 4% of the study area; however, the ecological impact of that infrastructure was much greater. The entire study area was within one-half mile of a road, pipeline corridor, well head, or other infrastructure, while 97% fell within one-quarter mile. Study results also showed the total number, total acreage, and the percent of study area remaining in core areas decreased as the width of the infrastructure impact increased. No core areas remained within one-half mile of infrastructure, and only 27% remained within 500 feet of infrastructure. These results, combined with a review of the scientific literature for fragmentation impacts to western focal species, indicated there was little to no place in the study area where wildlife would not be impacted.

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313 Weller et al. 2002.

314 Note that this density is between that of single horizontal wells (9 per square mile) and vertical wells (16 per square mile) expected in New York (section 5.1.3.2).

Study 2, Implications for New York: This study demonstrated that impacts to wildlife extended beyond the direct effects from the land physically altered by oil and gas fields. Note that the overall impacts predicted in the study were likely conservative as the data were only assessed at the individual gas field scale, not the broader landscape. While well densities from multiple horizontal wells from a common pad (a minimum of 1 well pad per square mile) would be less than in this study, all three drilling scenarios might result in negative impacts to wildlife in New York, as the impacts predicted to the complement of species in Wyoming were so extreme.

6.4.1.1 Impacts of Grassland Fragmentation

Grassland birds have been declining faster than any other habitat-species suite in the northeastern United States.[315] The primary cause of these declines is the fragmentation of habitat caused by the abandonment of agricultural lands, causing habitat loss due to reversion to later successional stages or due to sprawl development. Remaining potential habitat is also being lost or severely degraded by intensification of agricultural practices (e.g., conversion to row crops or early and frequent mowing of hayfields).

Stabilizing the declines of populations of grassland birds has been identified as a conservation priority by virtually all of the bird conservation initiatives, groups, and agencies in the northeastern US, as well as across the continent, due to concern over how precipitous their population declines have been across portions of their ranges (for the list of species of concern and their population trends, see Table 6.2). In New York, grassland bird population declines are linked strongly to the loss of agricultural grasslands, primarily hayfields and pastures; it is therefore critical to conserve priority grasslands in order to stabilize or reverse these declining trends.

[315] Morgan and Burger 2008.

Table 6.2 - Grassland Bird Population Trends at Three Scales from 1966 to 2005.[316] (New July 2011)

Species	New York trend (%/year)	New York population remaining (%)	USFWS Region 5 trend (%/year)	USFWS Region 5 population remaining (%)	Survey-wide trend (%/year)	Survey-wide population remaining (%)
Northern Harrier[1]	-3.4	25.9	1.1	153.2	**-1.7**	**51.2**
Upland Sandpiper[1]	-6.9	6.2	-0.7	76.0	0.5	121.5
Short-eared Owl[1]	--	--	--	--	**-4.6**	**15.9**
Sedge Wren[1]	-11.5	0.9	0.5	121.5	**1.8**	**200.5**
Henslow's Sparrow	-13.8	0.3	-12.6	0.5	**-7.9**	**4.0**
Grasshopper Sparrow[1]	**-9.4**	**2.1**	**-5.2**	**12.5**	**-3.8**	**22.1**
Bobolink[1]	-0.5	82.2	-0.3	88.9	**-1.8**	**49.2**
Loggerhead Shrike[1]	--	--	**-11.4**	**0.9**	**-3.7**	**23.0**
Horned Lark[2]	**-4.7**	**15.3**	**-2.1**	**43.7**	**-2.1**	**43.7**
Vesper Sparrow[2]	**-7.9**	**4.0**	**-5.4**	**11.5**	**-1.0**	**67.6**
Eastern Meadowlark[2]	**-4.9**	**14.1**	**-4.3**	**18.0**	**-2.9**	**31.7**
Savannah Sparrow[2]	**-2.6**	**35.8**	**-2.3**	**40.4**	**-0.9**	**70.3**

[1]Highest priority or [2]High priority for conservation

Note: Background colors correspond with "regional credibility measures" for the data as provided by the authors. **Blue** indicates no deficiencies, **Yellow** (yellow) indicates a deficiency, and **Red** indicates an important deficiency.

Bold indicates significant trends (P<0.05).

Some of New York's grassland birds have experienced steeper declines than others, or have a smaller population size and/or distribution across the state or region, and are therefore included in the highest priority tier in Table 6.2: northern harrier (*Circus cyaneus*), upland sandpiper (*Bartramia longicauda*), short-eared owl (*Asio flammeus*), sedge wren (*Cistothorus platensis*), Henslow's sparrow (*Ammodramus henslowii*), grasshopper sparrow (*Ammodramus savannarum*), bobolink (*Dolichonyx oryzivorus*), and loggerhead shrike (*Lanius ludovicianus*). Species included in the high priority tier are those that have been given relatively lower priority, but whose populations are also declining and are in need of conservation. The high priority tier in

[316] Morgan and Burger, 2008.

Table 6.2 includes: horned lark (*Eremophila alpestris*), vesper sparrow (*Pooecetes gramineus*), eastern meadowlark (*Sturnella magna*), and savannah sparrow (*Passerculus sandwichensis*).

While these birds rely on grasslands in New York as breeding habitat (in general), two of these species (northern harrier and short-eared owl) and several other raptor species also rely on grasslands for wintering habitat. For this reason, a third target group of birds are those species that rely on grassland habitats while they over-winter (or are year-round residents) in New York, and include: snowy owl (Bubo scandiacus), rough-legged hawk (Buteo lagopus), red-tailed hawk (Buteo jamaicensis), American kestrel (Falco sparverius), and northern shrike (Lanius excubitor).

The specific effects of drilling for natural gas on nesting grassland birds are not well studied. However, the level of development expected for multi-pad horizontal drilling and minimum patch sizes of habitat necessary for bird reproduction, unless mitigated, will result in substantial impacts from the fragmentation of existing grassland habitats. Minimum patch sizes would vary by species and by surrounding land uses, but studies have shown that a minimum patch size of between 30-100 acres is necessary to protect a wide assemblage of grassland-dependent species.[317]

6.4.1.2 Impacts of Forest Fragmentation

Forest fragmentation issues were the subject of two assessments referenced below which are specific to the East and address multiple horizontal well drilling from common pads. These studies, therefore, are more directly applicable to New York than previously mentioned western studies of vertical drilling. The Multi-Resolution Land Characteristic Dataset ("MRLC") (2004) indicates the following ratios of habitat types in the area underlain by the Marcellus shale in New York: 57% forested; 28% grassland/agricultural lands; and 3% scrub/shrub. The other 12% is divided evenly between developed land and open water/wetlands. As forests are the most common cover type, it is reasonable to assume that development of the Marcellus Shale would have a substantial impact on forest habitats and species.

[317] USFWS n.d., Sample and Mossman 1997, Mitchell et al, 2000.

Today, New York is 63% (18.95 million acres) forested[318] and is unlikely to substantially increase. Current forest parcelization and fragmentation trends will likely result in future losses of large, contiguous forested areas.[319] Therefore, protecting these remaining areas is very important for maintaining the diversity of wildlife in New York.

The forest complex provides key ecosystem services that provide substantial ecological, economic, and social benefits (water quality protection, clean air, flood protection, pollination, pest predation, wildlife habitat and diversity, recreational opportunities, etc.) that extend far beyond the boundaries of any individual forested area.

Large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches,[320]

Lands adjacent to well pads and infrastructure can also be affected, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on interior forest conditions.

Forest ecologists call this the edge effect. While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge.[321] Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest birds, for example, avoid areas near edges during nesting season because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, such as white-tailed deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory. Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on

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[318] NYSDEC, Forest Resource Assessment and Strategy, 2010.

[319] NYSDEC, Forest Resource Assessment and Strategy, 2010.

[320] Johnson, 2010, p. 19.

[321] Johnson, 2010, p. 11.

forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

Lessons Learned from Pennsylvania

Assessment 1, General Discussion: The Nature Conservancy (TNC) conducted an assessment in 2010[322] to develop credible energy development projections for horizontal hydraulic fracturing in Pennsylvania's Marcellus Shale by 2030, and how those projections might affect high priority conservation areas, including forests. The projections were informed scenarios, not predictions, for how much energy development might take place and where it was more and less probable. Project impacts, however, were based on measurements of actual spatial footprints for hundreds of well pads.

Potential Direct Impacts, Methodology and Assessment Findings: Projections of future Marcellus gas development impacts depended on robust spatial measurements for existing Marcellus well pads and infrastructure. This assessment compared aerial photos of Pennsylvania Department of Environmental Protection (PADEP) Marcellus well permit locations taken before and after development and precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania.

Well pads in Pennsylvania occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad (Figure 6.5).[323]

[322] Johnson, 2010.

[323] This is larger than the 7.4 acres predicted by IOGA to be disturbed in New York (section 6.4b).

Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	3.1	8.8
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	5.7	
Indirect forest impact from new edges	21.2	
TOTAL DIRECT AND INDIRECT IMPACTS	30	

Figure 6.5 - Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context[324] (New July 2011)

Another key variable for determining land-use and habitat impacts in this assessment was the number of wells on each pad; more wells per pad translated to less disturbance and infrastructure on the landscape. It is technically possible to put a dozen or more Marcellus wells on one pad. For the 242 well pads assessed in this study, the average in Pennsylvania has been 2 wells per pad to date (IOGA estimates the same for New York) as companies quickly moved on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). TNC assumed that in many cases, the gas company would return to these pads later and drill additional wells. This assumption may not be valid in New York where there is a three-year limit on well development (ECL 23-0501).

The TNC assessment developed low, medium, and high scenarios for the amount of energy development that might take place in Pennsylvania. The projections included a conservative estimate of 250 horizontal drilling rigs, each of which could drill one well per month, resulting in

[324] Taken from Johnson, 2010, p. 10.

an estimated 3,000 wells drilled annually. Estimates in New York predict less activity than this, but activity could result in approximately 40,000 wells by 2040.

The low scenario (6,000 well pads) assumed that each pad on average would have 10 wells, or 1 well pad per 620 acres. Because many leases are irregularly shaped, in mixed ownership, or their topography and geology impose constraints, TNC concluded that it is unlikely this scenario would develop in Pennsylvania. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur.[325]

The medium scenario for well pads assumed 6 wells on average would be drilled from each pad (10,000 well pads), or 1 pad per 386 acres. Industry generally agreed that 6 is the most likely number of wells they would be developing per pad for most of their leaseholds in Pennsylvania.[326]

The high scenario assumed each pad would have 4 wells drilled on average (15,000 well pads), or 1 pad per 258 acres. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years. While this scenario would result in a loss of less than 1% of Pennsylvania's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3% of local forest habitats.

In summary, 60,000 wells could be drilled by 2030 in the area underlain by the Marcellus Shale in Pennsylvania on between 6,000 and 15,000 new well pads (there are currently about 1,000), depending on how many wells are placed on each pad.

A majority (64%) of projected well locations were found in a forest setting for all three scenarios. By 2030, a range of between 34,000 and 82,000 acres of forest cover could be cleared by new Marcellus gas development in Pennsylvania. Some part of the cleared forest area would become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started.

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[325] Note that while no definitive number is provided in section 5.1.3.2, this is expected to be the most common spacing for horizontal drilling in New York's Marcellus Shale.

[326] Note that IOGA assumes that 6 horizontal wells would be drilled per pad in New York.

Potential Direct Impacts, Implications for New York: Direct land disturbance from horizontal hydraulic fracturing of Marcellus Shale in New York is expected to result in 7.4 acres of direct impacts from each well pad and associated infrastructure. This is different from the experiences in Pennsylvania where nearly 9 acres of habitat was removed for each well pad and its associated infrastructure. Under either scenario, the direct impacts are substantial.

The most likely drilling scenario in Pennsylvania would result in a density of 1 pad per 386 acres. However, given New York's regulatory structure, a spacing of 1 pad per 640 acres is anticipated. If spacing units are less than 640 acres, or if there are less than 6-8 horizontal wells per pad, the percentage of land disturbance could be greater. Again, using the set of currently pending applications as an example, the 47 proposed horizontal wells would be drilled on eleven separate well pads, with between 2 and 6 wells for each pad. Therefore, greater than 1.2% land disturbance per pad estimated by industry can be expected in New York.

Potential Indirect Impacts, Methodology and Assessment Findings: To assess the potential interior forest habitat impact, a 100-meter buffer was created into forest patches from new edges created by well pad and associated infrastructure development (Figure 6.6). For those well sites developed in forest areas or along forest edges (about half of the assessed sites), TNC calculated an average of 21 acres of interior forest habitat was lost. Thus, the total combined loss of habitat was 30 acres per well pad due to direct and indirect impacts. Figure 6.5 summarizes these data.

In addition to the direct clearing of between 34,000 to 82,000 acres of forest cover in Pennsylvania, forest interior species could be negatively impacted within an additional 85,000 to 190,000 forest acres adjacent to Marcellus development. Forest impacts would be concentrated where many of Pennsylvania's largest and most intact forest patches occur, resulting in fragmentation into smaller patches by well pads, roads, and other infrastructure. In contrast to overall forest loss, projected Marcellus gas development scenarios in Pennsylvania indicate a more pronounced impact on large forest patches. Impacts to forest interior species would vary depending on their geographic distribution and density. Some species, such as the black-throated blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state, while widely distributed species such as the scarlet tanager, would be relatively less affected.

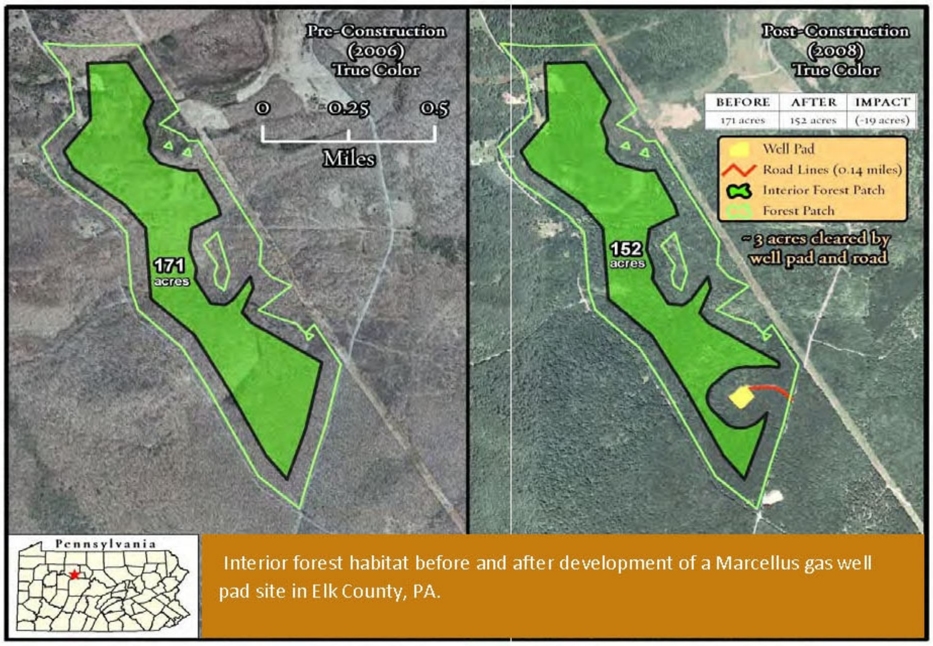
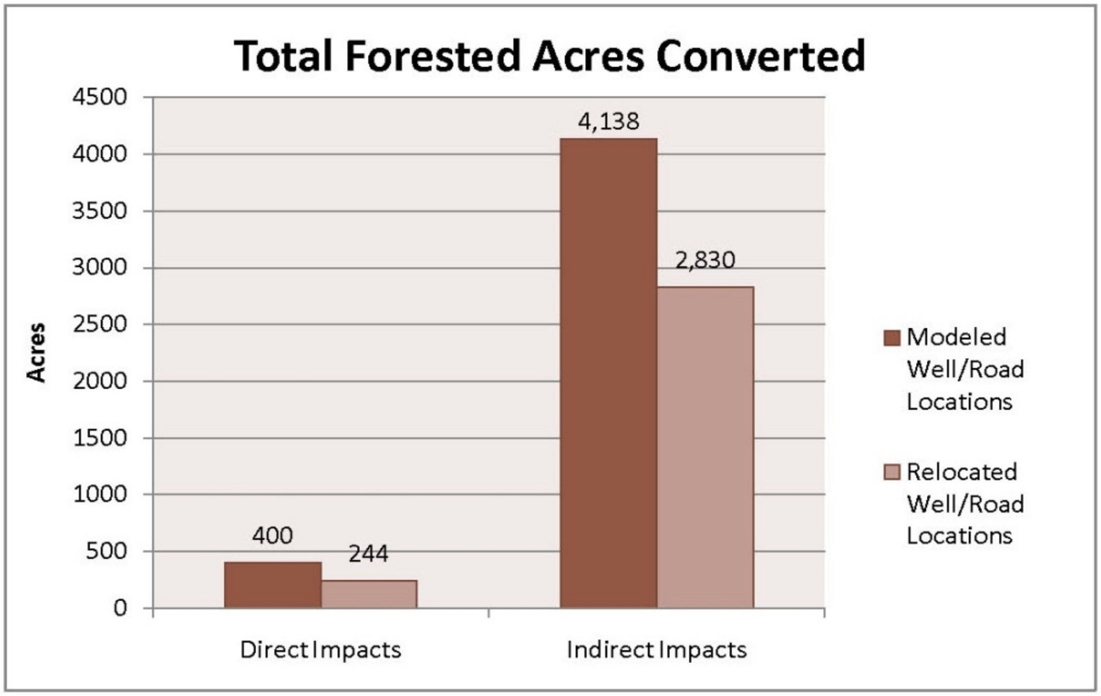


Figure 6.6 – Interior Forest Habitat Before & After Development of a Marcellus Gas Well Pad, Elk County PA[327] (New July 2011)

This study went on to find that locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas. To address this finding and explore potential ways in which conservation impacts could be minimized, TNC examined how projected Marcellus gas pads could be relocated to avoid forest patches in a specific region of Pennsylvania. To reduce the impacts to forest habitats, the wells were hypothetically relocated, where practicable, to nearby existing openings maintained by human activity (e.g., old fields, agricultural fields). If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. This exercise did not eliminate forest impacts in this heavily forested Pennsylvania landscape, but there was a significant reduction in impacts. Total forest loss declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by one-third (Figure 6.7). The study authors recommend that information about Pennsylvania's important natural habitats be an important part of the calculus about trade-offs and optimization as energy development proceeds.

[327] Taken from Johnson, 2010, p. 11.

Figure 6.7 - Total Forest Areas Converted[328] (New July 2011)



Potential Indirect Impacts, Implications for New York: For each acre of forest directly cleared for well pads and infrastructure in New York, an additional 2.5 acres can be expected to be indirectly impacted. Interior forest bird species with restricted breeding habitats, such as the black-throated blue and cerulean warblers, might be highly impacted.

Additional assessment work conducted for New York based on estimates and locations of well pad densities across the Marcellus landscape could better quantify expected impacts to forest interior habitats and wildlife.

New York Forest Matrix and Landscape Connectivity

Forest matrix blocks contain mature forests with old trees, understories, and soils that guarantee increased structural diversity and habitat important to many species. They include important stabilizing features such as large, decaying trunks on the forest floor and big, standing snags. Set within these matrix forests are smaller ecosystems offering a wide range of habitat (wetlands,

[328] Taken from Johnson, 2010, p. 27

streams, and riparian areas) that depend on the surrounding forested landscape for their long-term persistence and health. These large, contiguous areas are viable examples of the dominant forest types that, if protected, and in some cases allowed to regain their natural condition, serve as critical source areas for all species requiring interior forest conditions. Few remnants of such matrix blocks remain in the Northeast; it is therefore critical to conserve these priority areas to ensure long-term conservation of biodiversity.[329]

Assessment 2, General Discussion: The New York Natural Heritage program in 2010[330] identified New York's forest matrix blocks and predicted corresponding forest connectivity areas. Securing connections between major forested landscapes and their imbedded matrix forest blocks is important for the maintenance of viable populations of species, especially those that are wide-ranging and highly mobile, and ecological processes such as dispersal and pollination over the long term. Identifying, maintaining, and enhancing these connections represents a critical adaptation strategy if species are to shift their ranges in response to climate change and other landscape changes.

Assessment 2, Findings. Figure 6.8 depicts the large forested landscapes within New York and predicts the linkages between them, called least-cost path (LCP). A least-cost path corridor represents the most favorable dispersal path for forest species based on a combination of percent natural forest cover in a defined area, barriers to movement, and distance traveled. Thus, as many species that live in forests generally prefer to travel through a landscape with less human development (i.e., fewer impediments to transit) as well as in a relatively direct line, the predicted routes depict a balance of these sometimes opposing needs.

Assessment 2, Implications for New York: The area underlain by the Marcellus Shale in New York is 57% forested with about 7% of that forest cover occurring on State-owned lands. It is reasonable to assume high-volume horizontal hydraulic fracturing would have negative impacts to forest habitats similar to those predicted in Pennsylvania (Section 6.4.1.2).

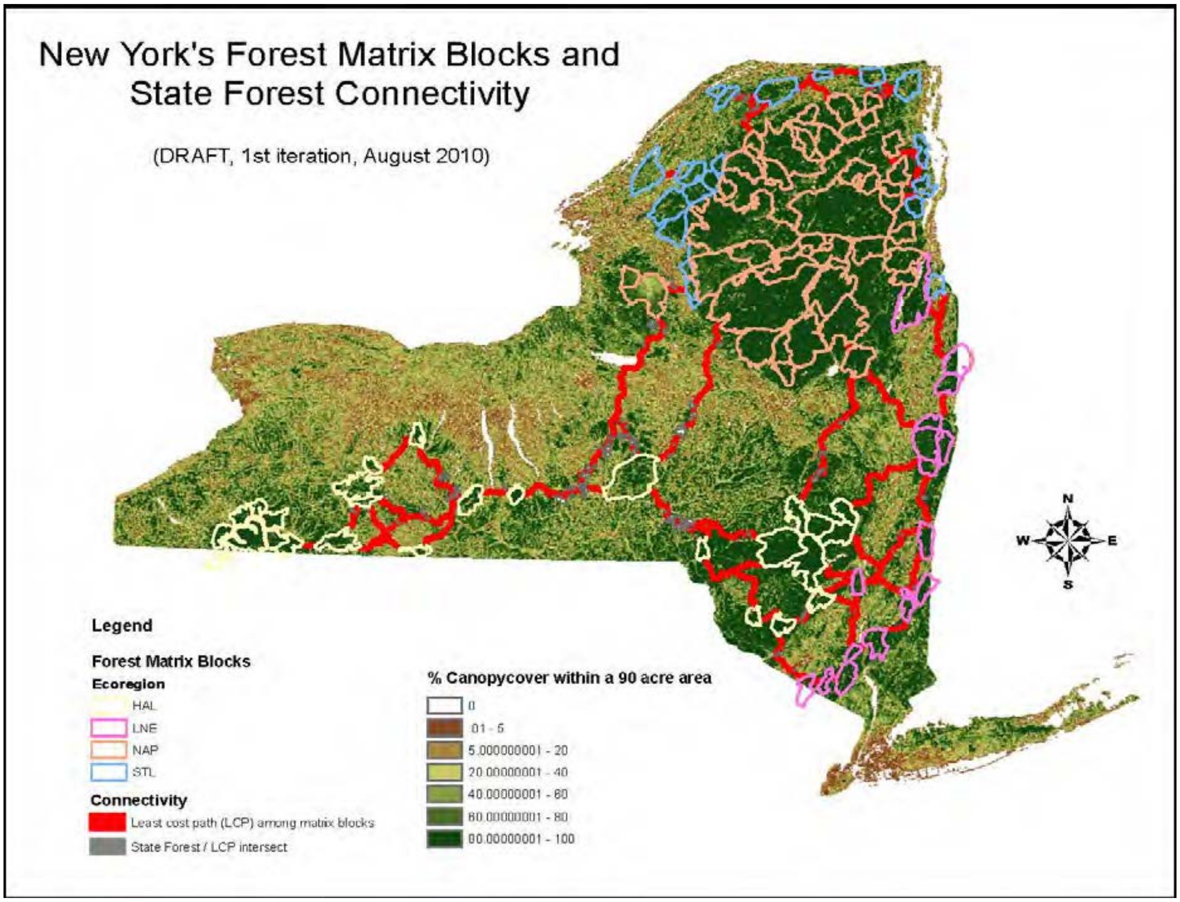
In order to minimize habitat fragmentation and resulting restrictions to species movement in the area underlain by the Marcellus, it is recommended that forest matrix blocks be managed to

[329] TNC 2004.

[330] NYSDEC, Strategic Plan for State Forest Management, 2010.

create, maintain, and enhance the forest cover characteristics that are most beneficial to the priority species that may use them.

Figure 6.8 - New York's Forest Matrix Blocks and State Connectivity[331] (New July 2011)



HAL = High Allegheny Plateau; LNE = Lower New England/Northern Piedmont; NAP= Northern Appalachian/ Acadian; STL= St. Lawrence-Champlain Valley

6.4.2 Invasive Species

An invasive species, as defined by ECL §9-1703, 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.

[331] Taken from NYSDEC, Strategic Plan for State Forest Management, 2010.

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.[332]

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.

6.4.2.1 Terrestrial

Terrestrial plant species which are widely recognized as invasive[333] or potentially-invasive in New York State, and are therefore of concern, are listed in Table 6.3 below.

Table 6.3 - Terrestrial Invasive Plant Species In New York State (Interim List) [334,335]

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*

[332] ECL §9-1701.

[333] As per ECL §9-1703.

[334] NYSDEC, DFWMR March 13, 2009. Interim List of Invasive Plant Species in New York State

[335] 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.

Terrestrial – Herbaceous	
Common Name	**Scientific Name**
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*
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 fresh water 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.

6.4.2.2 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[336] or potentially-invasive in New York State are listed in Table 6.4.

[336] As per ECL §9-1703.

Table 6.4 - Aquatic, Wetland & Littoral Invasive Plant Species in New York State (Interim List)[337,338]

Floating & Submerged Aquatic	
Common Name	**Scientific Name**
Carolina Fanwort	*Cabomba caroliniana*
Rock Snot (didymo)	*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*

337 NYSDEC, DRWMR March 13, 2009 Interim List of Invasive Plant Species in New York State

338 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.

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 potential mechanisms for the possible transfer of invasive aquatic species may include trucks, hoses, pipelines and other equipment used for water withdrawal and transport.

6.4.3 Impacts to Endangered and Threatened Species

The area underlain by the Marcellus Shale includes both terrestrial and aquatic habitat for 18 animal species listed as endangered or threatened in New York State (Table 6.5 and Figure 6.9) protected under the State Endangered Species Law (ECL 11-0535) and associated regulations (6 NYCRR Part 182). Some species, such as the northern harrier and upland sandpiper, are dependent upon grassland habitat for breeding and foraging and can be found in many counties within the project area. Species such as the rayed bean mussel and mooneye fish are aquatic species limited to only two counties on the western edge of the project area. Other species are associated with woodlands, with bald eagles nesting in woodlands adjacent to lakes, rivers and ponds throughout many counties within the project area. The area also includes habitat for cerulean warblers and eastern hellbenders, two species currently under consideration for listing by both the State and the federal government.

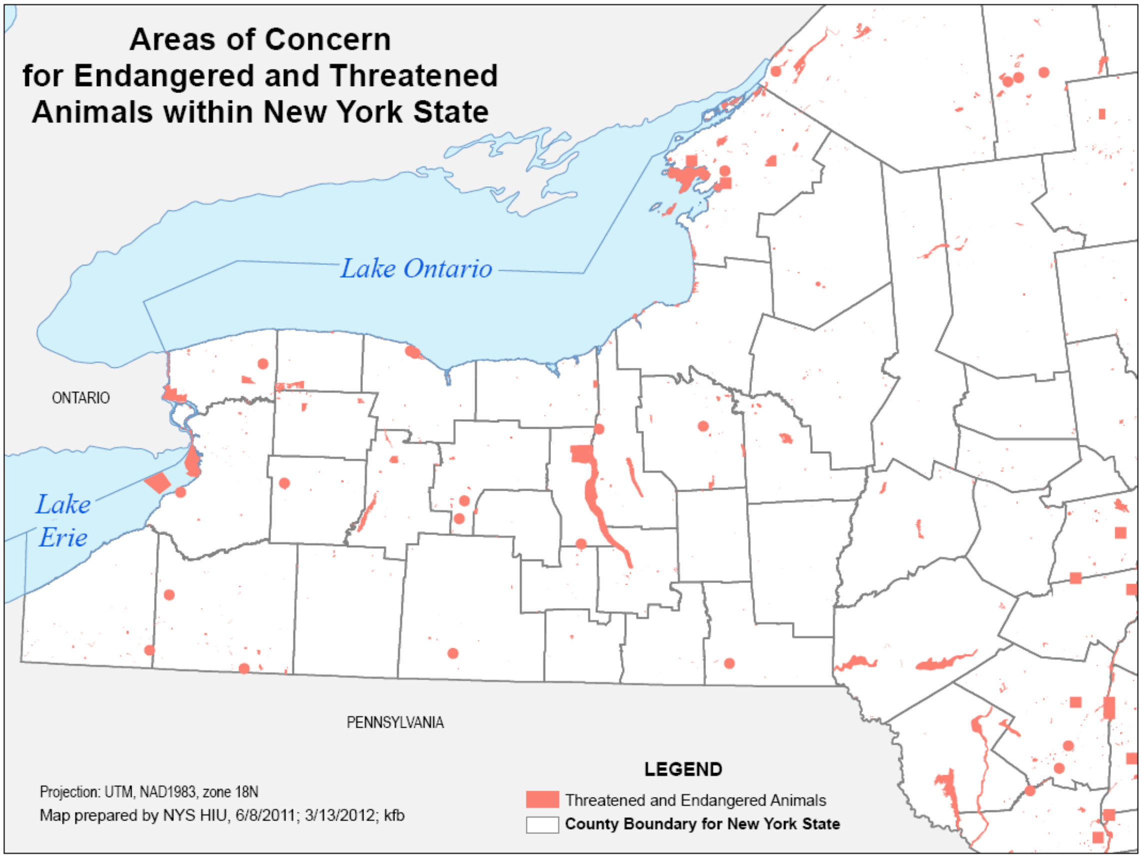
Endangered and threatened wildlife may be adversely impacted through project actions such as clearing, grading and road building that occur within the habitats that they occupy. Certain species are unable to avoid direct impact due to their inherent poor mobility (e.g., Blanding's turtle, club shell mussel). Certain actions, such as clearing of vegetation or alteration of stream beds, can also result in the loss of nesting and spawning areas. If these actions occur during the time of year that species are breeding, there can be a direct loss of eggs and/or young. For species that are limited to specific habitat types for breeding, the loss of the breeding area can result in a loss of productivity in future years as adults are forced into less suitable habitat. Any road construction through streams or wetlands within habitats occupied by these species can result in the creation of impermeable barriers to movement for aquatic species and reduce dispersal for some terrestrial species. Other impacts from the project, such as increased vehicle traffic, can result in direct mortality of adult animals. In general, the loss of habitat in areas occupied by listed species can result in reduced numbers of breeding pairs and lowered productivity.

Table 6.5 - Endangered & Threatened Animal Species within the Area Underlain by the Marcellus Shale [339](New July 2011)

Common Name	**Scientific name**	**NYS Listing**	**Primary Habitats**
Henslow's Sparrow	*Ammodramus henslowii*	Threatened	Grassland
Short-eared Owl	*Asio flammeus*	Endangered	Grassland
Upland Sandpiper	*Bartramia longicauda*	Threatened	Grassland
Northern Harrier	*Circus cyaneus*	Threatened	Grassland, wetlands
Sedge Wren	*Cistothorus platensis*	Threatened	Grassland
Peregrine Falcon	*Falco peregrinus*	Endangered	Cliff faces
Bald Eagle	*Haliaeetus leucocephalus*	Threatened	Forest, open water
Least Bittern	*Ixobrychus exilis*	Threatened	Wetlands
Pie-billed Grebe	*Podilymbus podiceps*	Threatened	Wetlands
Eastern Sand Darter	*Ammocrypta pellucida*	Threatened	Streams
Mooneye	*Hiodon tergisus*	Endangered	Large Lakes, Rivers
Longhead Darter	*Percina macrocephala*	Threatened	Large Streams, Rivers
Brook Floater	*Alasmidonta varicosa*	Threatened	Streams and Rivers
Wavyrayed Lampmussel	*Lampsilis fasciola*	Threatened	Small, Medium Streams
Green Floater	*Lasmigona subviridis*	Threatened	Small, Medium Streams
Clubshell	*Pleurobema clava*	Endangered	Small, Medium Streams
Rayed Bean	*Villosa fabalis*	Endangered	Small Streams
Timber rattlesnake	*Crotalus horridus*	Threatened	Forest

[339] November 3, 2010

Figure 6.9 - Areas of Concern for Endangered and Threatened Animal Species, March 31, 2011 (New July 2011)



6.4.4 Impacts to State-Owned Lands

State-owned lands play a unique role in New York's landscape because they are managed under public ownership to allow for sustainable use of natural resources, provide recreational opportunities for all New Yorkers, and provide important wildlife habitat and open space. They represent the most significant portions of large contiguous forest patch in the study area. Industrial development on these lands is, for the most part, prohibited, and any type of clearing and development on these lands is limited and managed. Given the level of development expected for multi-pad horizontal drilling, it is anticipated that there would be additional pressure for surface disturbance on state-owned lands. Surface disturbance associated with gas extraction could have a significant adverse impact on habitats contained on the state-owned lands, and recreational use of those lands.

Forest Habitat Fragmentation

As described earlier, large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, and provide more habitat for forest interior species. State-owned lands, by their very nature, consist of large contiguous forest patches. While some fragmentation has occurred, the level of activity associated with multi-well horizontal drilling (e.g., well pad construction, access roads, pipelines, etc.) would negatively impact the state's ability to maintain the existing large contiguous patches of forest.

The Department has stated that protecting these areas from further fragmentation is a high priority. One of the objectives stated in the Strategic Plan for State Forest Management is to "emphasize closed canopy and interior forest conditions to maintain and enhance" forest matrix blocks. It is critical therefore, that any additional road, pipeline and well pad construction be carefully assessed in order to avoid further reducing this habitat (see also Section 6.4.1). Given the State's responsibility to protect these lands as steward of the public trust, the State has a heightened responsibility, as compared to its role with respect to private lands, to ensure that any State permitted action does not adversely impact the ecosystems and habitat on these public lands so that they may be enjoyed by future generations.

Public Recreation

State-owned lands have been acquired over the past century to provide compatible public recreation opportunities, protect watersheds, and provide sustainable timber harvesting. Drilling and trucking activities disturb the tranquility found on these lands and can cause significant visual impacts. Also, many State Forest roads serve as recreational trails for bicyclists, horseback riders, snowmobilers and others. The level of truck traffic associated with horizontal drilling and high-volume hydraulic fracturing presents safety issues, and would significantly degrade the experience for users of these roads, if not altogether during the drilling and construction phases of development.

Legal Considerations

State Forests have an identity that is distinct from private lands, prescribed by the NYS Constitution, the ECL and the Environmental Quality Bond Acts of 1972 and 1986, under the provisions of which they were acquired. New York State Constitution Article XIV, Section 3(1) states:

> *"Forest and wild life conservation are hereby declared to be policies of the state. For the purposes of carrying out such policies the legislature may appropriate moneys for the acquisition by the state of land, outside of the Adirondack and Catskill parks as now fixed by law, for the practice of forest or wild life conservation."*

ECL Section 9-0501(1), in keeping with the above constitutional provision, authorizes the state to acquire reforestation areas, "which are adapted for reforestation and the establishment and maintenance thereon of forests for watershed protection, the production of timber and other forests products, and for recreation and kindred purposes,. . .which shall be forever devoted to the planting, growth and harvesting of such trees..."

Similarly, ECL Section 11-2103(1) authorizes the state to acquire "lands, waters or lands and waters…for the purpose of establishing and maintaining public hunting, trapping and fishing grounds."

ECL Section 9-0507 provides the Department discretionary authority to lease oil and gas rights on reforestation areas, provided that "such leasehold rights shall not interfere with the operation of such reforestation areas for the purposes for which they were acquired and as defined in Section 3 of Article XIV of the Constitution." The expected volume of truck traffic, the expected acreage that would be converted to non-forest use in the form of well pads, roads and pipelines, and noise and other impacts, raise serious questions as to how the surface activities anticipated with horizontal drilling and high-volume hydraulic fracturing could be viewed as consistent with this provision of the ECL.

For Wildlife Management Areas (WMAs) there are additional legal considerations stemming from the use of federal funds. Many WMAs were purchased using Federal Aid in Wildlife Restoration (Pittman-Robertson) funds and all are managed/maintained using Pittman-Robertson funds. Under these provisions, any surface use of the land must not be in conflict with the intended use as a WMA. These areas are managed for natural habitats to benefit wildlife, and disturbance associated with multi-pad wells raises questions about compatibility with essential wildlife behaviors such as breeding, raising young, and preparation for migration. Also, selling or leasing of minerals rights must be approved by the U.S. Fish and Wildlife Service, and may require reimbursement of the federal government for revenue generated. In addition, siting well pads on WMAs purchased with Conservation Fund monies may require additional mitigation under federal statutes and/or compensation.

6.5 Air Quality

6.5.1 Regulatory Overview

This section provides a comprehensive list of federal and New York State regulations which could potentially be applicable to air emissions and air quality impacts associated with the drilling, completion (hydraulic fracturing and flowback) and production phases (processing, transmission and storage). At each of these phases, there are a number of air emission sources that may be subject to regulation. These general regulatory requirements are then followed by specific information regarding emission sources that have potential regulatory implications, as presented below in Sections 6.5.1.1 to 6.5.1.8. Certain discussions reflect new industry information provided in response to Department requests, as well as finalization, clarification, and revision to EPA regulations and policy. For example, the definition of what constitutes a stationary source or "facility" has been refined for criteria pollutants. These discussions are then followed with Department rule-applicability determinations on in instances where such decisions can be made as part of the SGEIS, as well as how the Department envisions the permitting of specific operations should proceed (Section 6.5.1.8).

Applicable Federal Regulations

Prevention of Significant Deterioration of Air Quality (PSD): Under the PSD program, a federally-enforceable permit is required in order to restrict emissions from new major or major modification to existing sources (e.g., power plants and manufacturing facilities which emit criteria air pollutants in quantities above 100 tons per year) located in areas classified as attainment or unclassifiable with respect to the http://www.epa.gov/ttn/naaqs/. That is, PSD requirements apply to all pollutants that do not exceed the NAAQS in the source location area. The NAAQS are numerical maximum pollution levels set to protect public health and welfare which have been established for ozone (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), fine particulate matter (PM10 and PM2.5), carbon monoxide (CO) and lead. The federal PSD program is contained in 40 CFR Section 52.21 and the federally approved State program is found at 6 NYCRR Part 231.

Nonattainment New Source Review (NNSR): This federal program applies to new major or modified existing major sources in areas where the NAAQS are exceeded. The requirements for source emissions and potential impacts are more restrictive than through the PSD program. The federal program is found at 40 CFR Section 51.165 and the federally approved State program is found at 6 NYCRR Part 231. In New York State, nonattainment requirements are currently applicable to major sources of O_3 precursors (NO_x and VOC) and direct PM2.5 and its precursor emissions (SO_2 and NOx). EPA has approved 6 NYCRR Part 231 into the State Implementation Plan. The regulation is described further under "Applicable State Regulations" below.

New Source Performance Standards (NSPS): Section 111 of the Clean Air Act (CAA) requires EPA to adopt emissions standards that are applicable to new, modified, and reconstructed sources. The requirements are meant to force new facilities to perform as well as or better than the best existing facilities (commonly known as "best demonstrated technology"). As new technology advances are made, EPA is required to revise and update NSPS applicable to designated sources. The following federal NSPS may apply:

- 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). Subpart JJJJ applies to manufacturers, owners and operators of SI ICE which affects new, modified, and reconstructed stationary SI ICE (i.e., generators, pumps and compressors), combusting any fuel (i.e., gasoline, natural gas, LPG, landfill gas, digester gas etc.), except combustion turbines. The applicable emissions standards are based on engine type, fuel type, and manufacturing date. The regulated pollutants are NO_x, CO and VOC and there is a sulfur limit on gasoline. Subpart JJJJ would apply to facilities operating spark ignition engines at compressor stations;

- 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition (CI) ICEs. Subpart IIII applies to manufacturers, owners and operators of CI ICE (diesel) which affects new, modified, and reconstructed (commencing after July 11, 2005) stationary CI ICE (i.e., generators, pumps and compressors), except combustion turbines. The applicable emissions standards (phased in Tiers with increasing levels of stringency) are based on engine type and model year. The regulated pollutants are NO_x, PM, CO, non-methane hydrocarbons (NMHC), while the emissions of sulfur oxides

(SO_x) are reduced through the use of low sulfur fuel. Particulate emissions are also reduced by standards. Subpart IIII would apply to facilities operating compression ignition engines at compressor stations;

- 40 CFR Part 60, Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. Subpart KKK applies to gas processing plants that are engaged in the extraction of natural gas liquids from field gas and contains provisions for VOC leak detection and repair (LDAR);

- 40 CFR Part 60, Subpart LLL - Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions. Subpart LLL governs emissions of SO_2 from gas processing plants, specifically gas sweetening units (remove H_2S and CO_2 from sour gas) and sulfur recovery units (recover elemental sulfur); and

- 40 CFR Part 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

National Emission Standards for Hazardous Air Pollutants (NESHAPs): Section 112 of the CAA requires EPA to adopt standards to control emissions of hazardous air pollutants (HAPs). NESHAPs are applicable to both new and existing sources of HAPs, and there are NESHAPs for both "major" sources of HAPs and "area" sources of HAPs. A major source of HAPs is one with the potential to emit in excess of 10 Tpy of any single HAP or 25 Tpy of all HAPs, combined. An area source of HAPs is a stationary source of HAPs that is not major. The aim is to develop technology-based standards which require levels met by the best existing facilities. The pollutants of concern in the oil and gas sector primarily are the following: BTEX, formaldehyde, and n-hexane. The following federal NESHAPs may apply:

- 40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE). Appendix 17 has been revised from the initial analysis to reflect the requirements in the final EPA rule;

- 40 CFR Part 63, Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks. Subpart H applies to equipment that contacts fluids with a HAP concentration of 5%;

- 40 CFR Part 63, Subpart HH - NESHAPs from Oil and Natural Gas Production Facilities. Subpart HH controls air toxics from oil and natural gas production operations and contains provisions for both major sources and area sources of HAPs. Emission sources affected by this regulation are tanks with flash emissions (major sources only), equipment leaks (major sources only), and glycol dehydrators (major and area sources). Further details on this subpart are presented in section 6.5.1.2;

- 40 CFR Part 63, Subpart HHH - NESHAPs from Natural Gas Transmission and Storage Facilities. Subpart HHH controls air toxics from natural gas transmission and storage operations. It affects glycol dehydrators located at major sources of HAPs; and

- 40 CFR Part 61, Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources). Subpart V applies to equipment that contacts fluids with a volatile HAP concentration of 10%.

Applicable New York State Regulations

New York State Air Regulations are codified at 6 NYCRR Part 200 *et seq*, and can be obtained from the Department's web site at http://www.dec.ny.gov/regs/2492.html. Some of the applicable regulations are briefly described below.

- Part 200 - General Provisions;

    - Section 200.1 Definitions (relevant subsections);

      (cd) *Stationary source.* Any building, structure, facility or installation, excluding nonroad engines, that emits or may emit any air pollutant;

      (aw) *Nonroad engine.* (1) Except as specified in paragraph (2) of this subdivision, a nonroad engine is an internal combustion engine:

      (iii) that, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicators of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.

      (2) An internal combustion engine is not a nonroad engine if:

      (iii) the engine otherwise included in subparagraph (1)(iii) of this subdivision remains or would remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A *location* is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced would be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (*i.e.* at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph does not apply to an engine after the engine is removed from the location;

- Section 200.6 - Acceptable Ambient Air Quality. Section 200.6 states, "notwithstanding the provisions of this Subchapter, no person shall allow or permit any air contamination source to emit air contaminants in quantities which alone or in combination with emissions from other air contamination sources would contravene any applicable ambient air quality standard and/or cause air pollution. In such cases where contravention occurs or may occur, the commissioner shall specify the degree and/or method of emission control required". This regulation prohibiting air pollution, allowing the Department to evaluate ambient impacts from emission sources; and

- Section 200.7 - Maintenance of Equipment. Section 200.7 states, "any person who owns or operates an air contamination source which is equipped with an emission control device shall operate such device and keep it in a satisfactory state of maintenance and repair in accordance with ordinary and necessary practices, standards and procedures, inclusive of manufacturer's specifications, required to operate such device effectively.

- Part 201 - Permits and Registrations;

  - 201-2.1 Definitions.

    (21) Major stationary source or major source or major facility (see further details and discussions below);

  - 201-5 - State Facility Permits. Subpart 201-5 contains the criteria to issue "**s**tate facility permits" to facilities that are not considered to be major. These are generally facilities with the following characteristics: (1) Their actual emissions exceed 50% of the level that would make them major, but their potential to emit as defined in 6 NYCRR Part 200 does not place them in the major category, (2) They require the use of permit conditions to limit emissions below thresholds that would make them subject to certain state or federal requirements, or (3) They have been granted variances under the Department's air regulations;

- 201-6 - Title V Facility Permits. Subpart 201-6 contains the requirements and procedures for CAA "Title V Permits". These include facilities that are judged to be major under the Department's regulations, or that are subject to NSPSs, to a standard or other requirements regulating HAPs or to federal acid rain program requirements; and

- 201-7 - Federally Enforceable Emission Caps. Subpart 201-7 provides the ability to accept federally enforceable permit terms and conditions which restrict or cap emissions from a stationary source or emission unit in order to avoid being subject to one or more applicable requirements.

- Part 212 - General Process Emission Sources. In general, Part 212 regulates emissions of particulate, opacity, VOCs (from major sources), NO_x (from major sources) and is mainly used to control air toxics from industries not regulated in other specific 6 NYCRR Parts;

- Part 227- Stationary Combustion Installations (see Appendix 16 for more details):

  - 227-1- Stationary Combustion Installations. Subpart 227-1 regulates emissions from stationary combustion installations.

  - 227-2 - Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NO_x). Subpart 227-2 imposes NO_x limits on major sources (with a potential to emit 100 tons of NO_x per year) located in the attainment areas of the northeast ozone transport region;

- Part 229 - Petroleum and Volatile Organic Liquid Storage and Transfer. Part 229 regulates petroleum and volatile organic liquid storage and transfer (i.e., gasoline bulk plants, gasoline loading terminals, marine loading vessels, petroleum liquid storage tanks or volatile organic liquid storage tanks); and

- Part 231- New Source Review (NSR) for New and Modified Facilities. Part 231 addresses both the federal NSR and PSD requirements for sources located in nonattainment or attainment areas and the relevant program requirements. For new major facilities or modification of existing major facilities, Part 231 applies to those NSR pollutants with proposed emissions increases greater than the major facility or significant project threshold, as applicable. The applicable PSD major facility threshold (100 or 250 tons per year) is determined by whether the facility belongs to one of the source categories listed in 6 NYCRR §201-2.1(b)(21)(iii). Reciprocating internal combustion engines are not on the list, making the major source threshold 250 tons per year (instead of 100 tons/year) for PSD applicable pollutants. For the nonattainment pollutants, the threshold levels are lower, and depend on the location of the proposed new facility or modification. For the Marcellus Shale area, which is located within the Ozone Transport Region (OTR), for regulatory purposes, the area is treated as moderate ozone nonattainment. The major facility thresholds are 50 tons per year for VOC and 100 tons per year for NOx.

The following sections discuss what regulatory determinations the Department has made with respect to operations associated with drilling and completion activities and how the regulatory process would be used for further permitting determinations related to the offsite compressor stations and its association with the well pad operations.

6.5.1.1 Emission Analysis NO_x - 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 and 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 their target formations. For the development of the Marcellus Shale, this power would 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 appear as Table 6.6 below.

Table 6.6 - EPA AP-42 Emissions Factors Tables

EPA 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 value by the VOC weight fraction of the fuel gas.

EPA 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
Exhaust (TOC)	6.8	2.10	1.12	0.35
Evaporative (TOC)	0.30	0.09	0.00	0.00
Crankcase (TOC)	2.2	0.69	0.02	0.01
Refueling (TOC)	0.5	0.15	0.00	0.00

Engine Emissions Example Calculations

A characterization of the significant NO_x 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,[340] using NO_x emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus Shale formation outside New York State, a representative NO_x emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential

[340] Engine information provided by Chesapeake Energy

to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NO_x emission would be:

$$NO_x \text{ emissions} = (6.4 \text{ g/Hp-hr}) \times (5400 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 333.7 \text{ Tpy}$$

The actual emissions from the engines would be much lower than the above PTE estimate, depending on the number of wells drilled and the time it takes to drill the wells at a well site in a given year.

2. Horizontally Drilled/ High-Volume Hydraulically Fractured Wells - Completion Phase

For diesel-drive 2333 Hp fracturing pump engine(s),[341] using NO_x emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus Shale formation outside New York State, a representative NO_x 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 NO_x emission would be:

$$NO_x \text{ emissions} = (6.4 \text{ g/Hp-hr}) \times (2333 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 144.1 \text{ Tpy}$$

The actual emissions from the engines would be lower than the above PTE estimate, depending on the time it takes to hydraulically fracture each well and the number of wells hydraulically fractured at a well site in a given year.

3. Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Production Phase

Using recent permit application information from a natural gas compressor station in the Department's Region 8, a NO_x 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.[342] The engine(s) is expected to run year round (8760 hr/yr).

$$NO_x \text{ emissions} = (2.0 \text{ g/Hp-hr}) \times (2500 \text{ Hp}) \times (8760 \text{ hr/yr}) \times (\text{ton}/2000 \text{ lb}) \times (1 \text{ lb}/453.6 \text{ g}) = 48.3 \text{ TPY}$$

[341] Engine information provided by Chesapeake Energy.

[342] Engine information provided by Chesapeake Energy.

Since the engines in the example comply with the NO_x RACT emission limits, non-applicability of the rule implies merely avoiding the monitoring requirements that were designed for permanently located engines. In addition to NO_x RACT requirements, Title V permitting requirements could also apply to other air pollutants such as CO, SO_2, particulate matter (PM), ozone (as VOCs), and elemental lead, with the same emission thresholds as for NO_x. An initial review of other emission information for these engines, such as CO and PM emission factor data, reveals an unlikely possibility of reaching major source thresholds triggering Title V permitting requirements for these facilities as discussed further in Section 6.5.1.8.

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 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 Subpart HH. 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 Pennsylvania indicates 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 would still likely be required to maintain records of the exemption determination as outlined in 40 CFR §63.774(d) (1) (ii). Sources with a throughput of 3 MMscf/day or greater and benzene emissions of 1.0 Tpy or greater are subject to the rule's emission reduction requirements. 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 (fracturing 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 for a short period of time for testing purposes. Recovering the gas to a sales gas line is called a reduced emissions completion (REC). See Section 6.6.8 for further discussion of RECs.

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 Public Service Commission (PSC) has not historically authorized construction of sales lines before the first well is drilled on a pad (see Section 8.1.2.1 for a discussion of the PSC's role and a presentation of reasons why pre-authorization of gathering lines have been suggested under certain circumstances), therefore, estimates of emissions from both flaring and venting of flowback gas are included in the emissions tables in Section 6.5.1.6**.** Unless PSC revisits this policy in the future in order to allow for REC, the well pad activities would be required to minimize these emissions due to the potential for relatively high short-term VOC and CO emissions, as estimated by the Industry Information Report. The modeling and regional emission assessments, as well as regulatory applicability discussions, have incorporated industry's quantifications of the short term operations associated with flaring and venting. Thus, the well permitting process would be constrained by the assumed amount of gas to be vented or flared (or the corresponding average maximum hours of operations).

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.

Gas from the Marcellus Shale in New York is expected to be "dry", i.e., have little or no VOC content, and "sweet", i.e., have little or no H_2S. 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 can be improved as more experience is gained in a shale play. Based on industry information submitted in response to Department requests, it is expected that no more than four wells could be drilled, completed, and hooked up to production in any 12-month period. Therefore, the annual emission estimates presented in Section 6.5.1.7 are based on an assumed maximum of four wells per site per year.

6.5.1.5 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 Pennsylvania's Marcellus Shale area indicates insufficient BTEX and other liquid hydrocarbon content to justify installation of collection and storage equipment for natural gas liquids. However, in the instances where "wet" gas is encountered and there is a need to store the condensate in tanks either at the well pad or at the compressor station, potential VOC and HAP (e.g., benzene) emissions should be minimized to the maximum extent practicable and controlled where necessary. The ALL report notes that it is difficult to properly quantify the loss of vapors from these tanks, but notes that in states where substantial quantities of condensate are recovered, either a vapor recovery system or flaring is used to control emissions. If such condensate tanks are to be used in New York, a vapor recovery system would be required to be installed instead of flaring the emissions since the latter creates additional combustion emissions and other potential issues.

6.5.1.6 Emissions Tables

Estimated annual emissions from drilling, completion and production activities are based on industry's response to the Department's information requests[343] (hereafter Industry Information Report) that a maximum number of four wells would be drilled at a given pad in any year (see further discussion in the modeling section). These estimates are presented in Table 6.7, Table 6.8, Table 6.9, and Table 6.10 below.

[343] ALL Consultant Information Request Report on behalf of IOGANY, dated September 16, 2010.

Table 6.7 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Flaring (Tpy)(Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	1.4	2.3
NO_x	15.1	5.8	3.8	24.7	4.9	29.6
CO	8.3	3.2	9.2	20.7	24.5	45.2
VOC	0.8	0.2	2.4	3.4	0.7	4.1
SO_2	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.03	0.14	0.08	0.22

Table 6.8 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Venting (Tpy)(Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	0.0	0.9
NO_x	15.1	5.8	3.8	24.7	0.0	24.7
CO	8.3	3.2	9.2	20.7	0.0	20.7
VOC	0.8	0.2	2.4	3.4	0.6	4.0
SO_2	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.03	0.14	0.0	0.14

Table 6.9 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Flaring (Tpy) (Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	1.4	2.3
NO_x	15.1	5.8	3.8	24.7	4.9	29.6
CO	8.3	3.2	9.2	20.7	24.5	45.2
VOC	0.8	0.2	2.4	3.4	0.7	4.1
SO_2	0.02	0.01	0.07	0.1	0.22	0.31
Total HAPs	0.09	0.02	0.31	0.42	0.69	1.11

Table 6.10 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Venting (Tpy) (Updated July 2011)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	0.5	0.2	0.2	0.9	0.0	0.9
NO_x	15.1	5.8	3.8	24.7	0.0	24.7
CO	8.3	3.2	9.2	20.7	0.0	20.7
VOC	0.8	0.2	2.4	3.4	21.9	25.3
SO_2	0.02	0.01	0.07	0.1	0.0	0.1
Total HAPs	0.09	0.02	0.31	0.42	0.002	0.422

It is important to understand that the "totals" columns in these tables are not meant to be compared to the major source thresholds discussed in section 6.5.1.2 for the purpose of determining source applicability to the various regulations. This is because these estimates include emissions from activities which are not considered stationary sources, as detailed in the discussions in Section 6.5.1.8. These estimates should be looked upon merely as giving a relative sense of the expected well pad emissions and what the relation is to major source thresholds.

6.5.1.7 Offsite Gas Gathering Station Engine

For gas gathering compression, it is anticipated that most operators would 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.

The final revision to NESHAPs Subpart ZZZZ has placed very strict limits on formaldehyde emissions from reciprocating internal combustion engines (see Appendix 17). Future, 4-stroke lean-burn engines would be required to have an oxidation catalyst that would reduce formaldehyde emissions by approximately 90%.

The annual emissions data for a typical gas gathering compressor engine is given in Table 6.11 below.[344]

Table 6.11 - Estimated Off-Site Compressor Station Emissions (Tpy)

Component	Controlled 4-Stroke Lean Burn Engine
PM	0.5
NO_x	33.3
CO	6.6
SO_2	0.0
Total VOC	5.0
Total HAP	2.7

[344] ALL Consulting August 26, 2009.

6.5.1.8 Department Determinations on the Air Permitting Process Relative to Marcellus Shale High-Volume Hydraulic Fracturing Development Activities.

A determination would first be made as to whether these internal combustion engines (ICEs) would qualify for the definition of non-road or stationary sources. This, in turn, determines whether the engines are subject to requirements such as NSPS or NESHAPs.

When considering applicability of these rules, engines can fall into three general classes: stationary, mobile, or nonroad. The applicable NSPS regulations (40 CFR Part 60, Subpart IIII and Subpart JJJJ) and NESHAP (40 CFR Part 63 Subpart ZZZZ) define stationary internal combustion engines as excluding mobile engines and nonroad engines. The New York State definition of stationary sources given in 6.5.1 also notes the non-road engine exclusion. The latter engines are defined at 40 CFR Part 1068 (General Compliance Provisions for Nonroad Program), which is virtually the same as it appears in 40 CFR Part 89 (Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines) as well as in New York's regulations at NYCRR Part 200.1, as given in Section 6.5.1. Paragraph (1)(iii) of the definition describes a nonroad engine that would be portable or would be part of equipment that would be considered portable, with the exception given in paragraph 2(iii) if the engines are to remain at the same location for more than 12 months.

It is clear from the Industry Information Report that the engines used to power the drilling and well development equipment would be used at a given well pad for maximum of less than half a year (see discussions in ALL, 8/26/09 and the modeling section on the timeframes of engine use), even if the maximum of four wells per pad were to be completed in a year. Thus, these engines are considered as nonroad engines and are not subject to the NSPS, NESHAP or permitting requirements.

However, as detailed in the following section, the environmental consequences of these engines are fully analyzed and mitigated where necessary in keeping with SEQRA. For example, the use of ULSF with a 15 ppm sulfur content would be required for use in all drilling and well development equipment engines. This limit is required for stationary engines in the final NESHAPS Subpart ZZZZ rule as discussed in Appendix 17. In addition, a set of control measures would be required on most of these engines in order to meet NAAQS, as fully addressed in the modeling analysis section. The permitting of the various activities associated with drilling and development activities in the Marcellus Shale would be consistent with regulatory scheme in 6 NYCRR Part 200, et. seq. for regulating emissions of air pollutants. Thus, the Department would not subject the nonroad engines to the regulatory requirements applicable to stationary source, such as the determination of what constitutes a major source per Part 201. In instances throughout the country reviewed by the Department in terms of permitting gas drilling and production activities, the determination of a stationary source or facility has relied on the association of the compressor stations and nearby well emissions, but in none of these were the nonroad engine emissions included in the permitting emission calculations. This approach would also be followed in New York as the appropriate regulatory scheme.

Thus, in accounting for the well site operation emissions in the permitting process, the emissions from Tables 1 to 4 above would only include the remaining activities at the site which are essentially a small line heater (1 million Btu) a small compressor (150 horsepower), and possibly a flare. Tables 1 to 4 indicate that for the three higher emission pollutants, NO_x, CO and VOCs, these sources would add up to a maximum of 8.7, 33.7, and 3.1 Tpy, respectively, under the normal dry gas scenario for each pad. In the unlikely event of encountering "wet" gas, the VOC emissions could be 24.3 Tpy. However, these CO and VOC emissions are associated with the transient sources, the flare and gas venting, respectively, which are to be minimized, as would be apparent in the discussions to follow. In addition, in the unlikely event that a glycol dehydration would be located at a well site instead of the compressor station, the strict regulatory requirement noted in Section 6.5.1 would limit the VOC (benzene) emissions to below 1 Tpy. Thus, total HAPs emissions from a well pad would be much less than even the major source threshold of 10 Tpy for a single HAP.

Therefore, the process which the Department would follow in permitting the air emissions from Marcellus Shale activities would start with the compressor station permit application review. As noted in Section 8.1.2.1, this SGEIS for drilling wells is not meant to address the full extent of the compressor station permitting and the environmental consequences, which falls under the purview of the PSC and would be dealt with on a case by case basis. The applicable Public Service Law, Article VII, would be followed in which PSC would be the lead agency for the environmental review, however the Department would remain the agency responsible for reviewing and acting on the air permit application. In this review, the Department would incorporate all of the applicable regulations, including the determination of what constitutes a source or facility. The air quality analysis has considered the impacts of a potential compressor station which is hypothetically placed next to the well pad in the modeling assessment of standards and other compliance thresholds.

Section 112(n) of the CAA (Section 112) applies specifically to HAPs. The EPA, on September 22, 2009, clarified that for the purposes of New Source Review (NSR) and Title V applicability review, the process of facility determination should include a detailed consideration of the traditional set of three criteria used by EPA in past actions. In this determination, a set of related and adjacent activities could be "aggregated" if they meet the requirements of the criteria.

The Department would follow EPA's process for the determination of a stationary source or facility for criteria pollutants, as also guided by recent applicability determinations by EPA and other states. Details of the Department's approach are presented in Appendix 18. The process would involve requesting information during the compressor station permit application phase using a set of questions framed from previous EPA determinations. A sentinel aspect of EPA's regulation and policy, which New York's approach is adapting, is the use of case-by-case information to make an informed decision. That process would also consider information requested on drilling wells which could be associated with the compressor stations.

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 low-permeability gas reservoirs, an air quality modeling analysis was undertaken by the Department's Division of Air Resources (DAR). The original modeling analysis 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, and it addressed a number of issues raised in public comments during the SGEIS scoping process. The analysis also incorporated subsequently-developed information on operational scenarios specific to multi-well horizontal drilling and hydraulic fracturing, to help determine possible air permitting requirements.

The initial modeling analysis has been updated based on information from both the Industry Information Report and related public information which has become available since September 2009. In particular, industry has indicated that: 1) simultaneous drilling and completion operations at a single pad would not occur; 2) the maximum number of wells to be drilled at a pad would be four in any 12-month period; and 3) flowback impoundments are not contemplated. The effects of these operational changes are discussed where appropriate. It is to be noted that the revision from maximum of ten wells down to four wells per pad per year affects only the annual emissions and the modeled annual impacts and not the short term impacts. Therefore, the annual impacts were revisited to determine if the reduced emissions had an effect on the previous conclusions reached on standards compliance. In instances where previous impacts due to emissions using ten wells did not pose an exceedance, the annual impacts have not been recalculated since these represent conservative concentrations versus the revised maximum of four well operations. Instances where this approach is used are noted in the subsequent discussions.

Due to remaining issues with exceedances of the 24-hour PM2.5 ambient standard and the adoption of new 1-hour SO_2 and NO_2 standards by EPA since the initial modeling analysis, a supplemental modeling analysis was performed. The approach to this assessment and the consequent results are presented in a separate section which follows this section. That assessment has incorporated the discussions from an industry modeling exercise for PM2.5 and PM10, as well as more recent EPA guidance documents on modeling for these pollutants.

This section presents the initial 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 Information Report.[345] To a limited extent, certain supplemental information from ICF International's report to NYSERDA[346] was also used. The applicability determinations of the Department's air permitting regulations and the verification approach to the emission calculations are contained in Section 6.5.2.

[345] ALL Consulting, 2009,

[346] ICF Task 2, 2009,

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. The supplemental modeling analysis indicates that, although the operational time frame for certain equipment (e.g., engines) over a given year would be reduced according to the Industry Information Report,[347] the consequences of these reduced annual emissions are only qualitatively addressed in the following sections since these do not affect any of the initial conclusions reached on annual impacts. That is, the reduced annual emissions from certain operations which were initially demonstrated to meet the corresponding standards and thresholds would only be lowered by this new information.

The air quality analysis relied upon recommended EPA and the Department's 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 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 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

[347] ALL Consulting, 2010.

guide the set of conditions under which a site specific assessment might or might not be necessary. Based on information in the Industry Information Report and an update to EPA's dispersion model, the initial PM10/PM2.5 modeling approach and conclusions have been updated.

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 would 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 Information 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 well pad 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 Information Report, Section 2.1.5 and Exhibit 2.2.1 of the ICF report, and in Chapter 5 of the SGEIS, and would 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 to any reliable extent without a well-defined source. The best approach to address these sources is to apply best minimization techniques, as recommended in Section 6.5.1.5 for condensate tanks. However, in instances where speciated VOCs or HAPs are available and provided by industry, 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 three “types” of potential sources: 1) combustion from engines, compressors, line heaters, and flares; 2) short-term venting of gas constituents which are not flared; and 3) emissions from truck activities near the well pad. 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 Information 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 Information 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 m 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 initial industry report noted 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 would 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. The Industry Information Report indicates that the number of wells drilled in a year at a given well pad would be four and asserts that there would not be any simultaneous operations of the well drilling and completion equipment engines. These revisions are incorporated in the supplemental modeling analysis section. Their influence on the results in this section is addressed in places where deemed of consequence.

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 Information 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 Information 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 Information Report as containing “heavier” hydrocarbons such as benzene. The industry and ICF reports note that gas samples in the Marcellus Shale have detected neither these heavier species of VOCs, nor H_2S. However, the Industry Information 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 Information 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 from processes other than flowback 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 Information 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 6.12 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.

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 CAA and are specifically exempt from permitting activities. Thus, these emissions are also not addressed in general 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 the Department's Commissioner's Policy CP-33.[348] Again, if these emissions are large enough, a modeling analysis is performed for an EIS. For the assessment of PM2.5 per CP-33, the emission calculations are not to include those associated with incidental roadway traffic away from the onsite operations.

[348] http://www.dec.ny.gov/chemical/8912.html.

Emissions of both PM10 and PM2.5 due to truck operations at the well pad were initially calculated by DAR's Mobile Source Panning Section 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 use of trucks at the well pad. These emissions are well below the CP-33 threshold of 15 Tpy. 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.

In order to address on-road truck traffic movement and emissions in the area underlain by the Marcellus Shale, estimates of regional emissions have been calculated based on information provided in the Industry Information Report. These regional emissions and their consequence are discussed in the section to follow. In addition, at the well pad, EPA's updated emission model MOVES (Motor Vehicle Emission Simulator) was used instead of the MOBILE 6e model used in the initial analysis. The MOVES model was also applied to generate regional emissions of on-road mobile sources associated with Marcellus Shale well development and included PM2.5 emissions. These estimates have been incorporated in the discussions of regional annual emissions. Results from the MOVES model indicate that the very low PM2.5 emissions initially estimated for a single pad are unchanged.

6.5.2.3 Modeling Procedures

EPA[349] and Department[350] guidelines 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

[349] Appendix W to 40 CFR Part 51. http://www.epa.gov/ttn/scram/guidance_permit.htm.

[350] http://www.dec.ny.gov/chemical/8923.html.

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 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 O_3 from NO_x and 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 Department “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 modeling analysis undertaken for this section. However, the potential consequences of regional emissions of VOCs and NO_x are presented in Section 6.5.3.

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 were 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 the Department’s Division of Air Resources (DAR) program policy document DAR-1.[351] 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 (NYSDOH) staff provided the requested information. For the thresholds, the Department’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.

[351] http://www.dec.ny.gov/chemical/30560.html.

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 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 6.10 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 would adequately envelope the set of conditions which would result in the maximum impacts from the relatively low-elevation or ground-level sources identified as sources of air pollutants. In addition, EPA and Department 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 gage 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-elevation sources would be well represented by the total of 12 years of data used in the analysis.

This analysis is conservative from the standpoint of the number of data years used. Certain public comments[352] recommended that the Department should use the EPA-recommended five years of data for its analysis. However, these comments do not fully recognize the conservative nature of using 12 years of meteorological data to determine the worst case impact for any potential site in the Marcellus Shale play. While the EPA and the Department guidance to use

[352] AKRF Consultants, memo dated 12/3/2009, p. 2.

five years of data applies to individual meteorological site analysis to account for possible climatological variability at the particular site, the use of 12 years of data from six different sites has a similar conservatism built into it by the end use of the overall maxima for any well pads or compressor stations. That is, the overall maxima for any specific pollutant and averaging time could be controlled by meteorological data from different NWS sites, but these maxima are being used for all potential sites in the Marcellus Shale play regardless of whether they might experience these meteorological conditions. A review of the results discussed in the next section and in Table 6.16 confirms this conclusion. Thus, it is deemed that the use of two years of data from six NWS sites to assess the maximum potential impacts is conservative.

The NWS sites and the two years of surface meteorological data which were readily available from each site are presented in Table 6.13, 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-elevation 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 by 150m 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 10m to allow for a minimum practical “buffer” zone between the equipment on the pad and its edge.

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-elevation and ground level sources which dominate the modeled set in this analysis, it is clear that maximum impacts would occur in close proximity to the sources. Thus, a dense grid of 10m spacing was placed along the “fencelines”, and extended on a Cartesian grid at 10 m grid spacing out to 100 m from the sources in all directions. In a few cases, the modeling grid was extended to a distance of 1000 m at a grid spacing of 25 m from the 100 m grid’s edge in order to determine the concentration gradients. For the combustion and venting sources, an initial grid at 10m increment was placed from the edge of the 150 m by 150 m pad area out to 1000 m, but this grid was reduced to a Cartesian grid of 20 m from spacing the “fenceline” to 500 m 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-elevation 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 Department 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 determine 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 Information 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 short term periods. 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 previously proposed 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 that 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 Information 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 previously-completed wells. For the modeling of the 24-hour PM2.5 impacts for the Supplemental Modeling section, the simultaneous operation scenario was not used based on the Industry Information Report. 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 Information 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 6.12 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-source 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 Information Report. The total emission rates for the latter sources were divided over the five representative sources in proper quantities. This scenario was revised for the Supplemental Modeling section by modeling each of the 15 completion equipment engines as individual point sources. 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. The one exception was the modeling of the NO_2 1-hour standard as describe in the next section. 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 fracturing 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 distinct types of rig engines and air 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. Revised industry information indicates that these “rain caps” open during engine operations and the supplemental modeling has incorporated this information. 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 6.11. The figure shows individual completion equipment engines as modeled in the supplemental analysis. 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 10m “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 and air compressors in Table 7 and for the hydraulic fracturing and flaring operations from Table 20 of the Industry Information 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. Although initial modeling included 10 wells per pad per year as an assumption, the resultant impacts were reviewed and relevant conclusions adjusted in the sections to follow where it was deemed of consequence to NAAQS or threshold compliance. That is, if the standards compliance was already demonstrated with the worst-case assumption of 10 wells, no revisions were necessary. On the other hand, the modeling has not included any operational limits 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 Section 6.5.2.4.

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 two "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; or b) as by-products of combustion of gas or fuel oil. A review of the data on these pollutants and their sources indicated that the two 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 Information 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 Information 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 Information 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 12 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 hydraulic fracturing pump engines, but the plume from the flame is calculated to be at a much higher elevation 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.

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 would 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 initially modeled, the averaging times of the standards are: for SO_2- 3-hour, 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 – 1-hour 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 exceedance 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 the Department's public webpage as well as from EPA's webpage.[353] For the attainment areas, EPA's Prevention of Significant Deterioration (PSD) regulations define increments for SO_2, NO_2 and PM10. More recently, EPA finalized the PSD increments for PM2.5; these are discussed below. Although, in the main, the PSD regulations apply only to major sources, the increments are consumed by both major and minor sources and would 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 can be qualified as temporary sources since the expectation is that the maximum number of wells at a pad can be drilled and completed well within a year. Even if a 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. Table 6.14 reflects incorporation of the 1-hour SO_2 and NO_2 NAAQS which are addressed in the supplemental modeling section. Furthermore, the final PSD increments for PM2.5, which become effective on December 20, 2011, are added to the Table.[354] 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% of the corresponding standards and are used to determine if a project would

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[353] http://www.dec.ny.gov/chemical/8403.html and http://www.epa.gov/ttn/naaqs/.

[354] Prevention of Significant Deterioration for PM2.5, final rule, Federal Register, Vol. 75, No. 202, October 20, 2010.

have a “significant contribution” to either an existing adverse condition or would cause a standards violation. Table 6.14 -also reflects the SILs for PM2.5 as contained in EPA’s final PSD rule.

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 exceedances 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 would 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 Department 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 Department’s public webpage.[355] 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 Department’s 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

[355] http://www.dec.ny.gov/chemical/8406.html.

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 6.14. These data represent worst case estimates of existing conditions to which the multi-well pad impacts would be added in order to determine total concentrations for comparison to the AAQS. In instances where the use of these maxima causes an exceedance of the AAQS, EPA and Department guidance identify procedures to define more case specific background levels. Per the Department's 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.

The background levels for criteria pollutants relied upon in the initial modeling analysis are still deemed conservative based on a review of observed monitoring levels in more recent years for pollutants such as PM2.5. Thus, most do not need to be updated. On the other hand, for PM2.5 24-hour averages and the new 1-hour NO_2 and SO_2 standards, more refined background levels were determined as discussed in the supplemental modeling section.

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 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 exceedances 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 Information Report, a few of the ambient thresholds could be exceeded. Certain of these exceedances 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 exceedances. 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 6.12 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 Information 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 NO_x 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 6.15. 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 6.15 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 6.14 (repeated in Table 6.16), 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 6.16 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 PM2.5 and the annual NO_2 were re-calculated for the compressor and line heater, as noted in Table 6.16. In addition, due to the promulgated PSD increments for PM2.5 in the 10/20/10 final rule, the increments are reflected in Table 6.16, along with the corresponding PM2.5 impacts (conservatively assuming to equal PM10 impacts). 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 would 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 would 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 7.6 m (30feet) stack height for the compressor and general adherence to the annual operational restrictions identified in the Industry Information 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 6.16. Unlike other cases, a simple adjustment to the stack height did not resolve these exceedances and it was determined that specific mitigation measures would need to be identified by industry. However, the Department determined one simple set of modeling 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 20 m, 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 6.16, it was determined that the receptor distance had to be beyond 80 m for PM10, and 500 m for PM2.5. In an attempt to determine if a stack height adjustment in combination with a distance limitation for public access approach can also alleviate the exceedances, 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 6.16 background levels, the receptors would be beyond 40 m and 500 m 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 $\mu g/m^3$), then the receptor distance at which a demonstration of compliance can be made is approximately 150 m.

Thus, one practical measure to alleviate the PM10 and PM2.5 standard exceedances 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 500 m would be required, but this distance could be reduced to 150 m 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 would need to be addressed by industry.

Based on recent industry and public information, supplemental modeling analysis and detailed review of potential control measures and their practical use was undertaken. The preliminary results clearly indicate that certain levels of emission reductions are likely necessary for at least the completion equipment engines. The results of the supplemental modeling and the consequent recommended mitigation measure are presented in the two sections which follow.

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 would 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 500 m 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 6.16 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 6.16 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/m^3. 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.

In addition to these results, the modeled impacts discussed in the supplemental modeling section and the remediation measures recommended to resolve modeled exceedances of both the 24-hour PM2.5 and 1-hour NO_2 NAAQS would substantially reduce both the PM2.5 and NO_2 impacts from the levels in Table 6.15 at the 500 m distance. Therefore, compliance with standards and increments can be said to be adequately demonstrated on the basis of individual pad results.

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/m^3 (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 6.17, along with this maximum normalized impact, results in the maximum 1-hour pollutant specific values in the third column of Table 6.17. The pollutants “shaded out” in the table are not vented from these sources. All of the worst case 1-hour impacts are well below the corresponding SGCs, but the maximum 1-hour impact of 61.5 µg/m^3 for H_2S (underlined top entry in the box) is above the New York standard of 14 µg/m^3.

Thus, if any “sour” gas is encountered in the Marcellus Shale, there would be a potential of exceedance of the H_2S standard. The maximum 1-hour impact occurred relatively close to the stack, and, in order to alleviate the exceedance, ambient air receptors would be excluded in all areas within at least 100 m of the stack. Alternately, it is possible to also reduce this impact by using a stack height which is higher than the conservative 3.7 m (12 ft) height provided in the Industry Information Report. Iterative calculations for the year with the maximum normalized impact indicated that a minimum stack height of 9.1 m (3 0 ft) would be necessary to reduce the impact to the 12.1 µg/m^3 value for H_2S reported in the “Max 1-hour” column of Table 6.18. With this requirement, all venting source impacts would be below the corresponding SGCs and standard.

For the set of seven pollutants resulting from the combustion sources and the dehydrator, it was previously discussed 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 Information 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 exceedances 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 exceedances were each associated with a particular source: the glycol dehydrator for benzene and the offsite compressor for formaldehyde. It should be noted that these exceedances 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 Information Report and with 90% reduction in formaldehyde emissions accounted for by the installation of an oxidation catalyst, by NESHAP Subpart JJJJ requirement for the compressor. 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 6.17 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 exceedances, 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 by either 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 (30ft), in which case it would also avoid building downwash effects, while the compressor stack would 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 would also reduce the corresponding 1-hour maxima leading to a larger margin of compliance with SGCs. With these stack modifications and the required NESHAP control measures, all of the SGCs and AGCs are projected to be met by the various combustion operations and the dehydrator. It should be noted that appropriate stack height for both the compressors and any associated dehydrators can be better determined by case-specific modeling during the compressor station permitting process if the dehydrator is to be located at the compressor station.

6.5.2.5 Supplemental Modeling Assessment for Short Term PM2.5, SO_2 and NO_2 Impacts and Mitigation Measures Necessary to Meet NAAQS.

As a supplement to the initial modeling, a number of additional model runs had to be made in order to address certain outstanding issues with PM10 and PM2.5 short term impacts from the original analysis, as well as to incorporate new information provided by industry. In addition, the re-assessment also addresses EPA's promulgated 1-hour NAAQS for SO_2 and NO_2 which became effective since September 2009. The modeling performed previously for PM10/PM2.5 was limited to a simplified set-up of the drilling and completion equipment engines and conservative set of assumptions which lead to substantial exceedances of the 24-hour NAAQS for both PM10 and PM2.5. Based on this preliminary result, it was deemed that further modeling would not resolve the exceedances without some level of emission mitigation.

Thus, industry was asked to provide a set of potential mitigation measures to alleviate these exceedances. In addition, the 2009 draft SGEIS identified a simple stack height and/or "fencing-in" of impacts option to be considered. This latter was not meant as the Department's suggested preferred mitigation option. Instead, the purpose behind the modeling with increased stack height was to provide a quantification of the level of simple physical adjustments to the operations in order for industry to incorporate the results in their assessment of mitigation and control measures. Based on both industry and public input, additional modeling analysis has been undertaken to address the PM10 and PM2.5 exceedances and the associated mitigation measures necessary to assume NAAQS compliance.

In addition to the PM10/PM2.5 issue, EPA promulgated new 1-hour standards for SO_2 and NO_2. These standards are 100 ppb (or 188 $\mu g/m^3$) for NO_2 , as the 3 year average of the 98th percentile of the daily maximum 1-hour values and 75 ppb (or 196 $\mu g/m^3$) for SO_2, as the 3 year average of the 99th percentile of the daily maximum 1-hour values, which became effective on April 12, 2010 and August 23, 2010, respectively[356]. These standards would be considered within the

[356] Federal Register: Vol 75, No. 26, pp 6474+ (2/9/10) and Vol. 75, No. 119, pp35520+ (6/22/10).

context of this SGEIS and in accordance with Subpart 200.6 requirement defined in Section 6.5.1 to assure all potential adverse impacts are identified and rectified. The additional assessments performed for these short term impacts are addressed separately to distinguish certain information for PM10/PM2.5 gathered from industry since the initial modeling analysis in the SGEIS.

A) PM 10 and PM2.5 24-hour Impact Modeling and Potential Mitigation Measures.

As part of the Industry's Responses (dated September 16, 2009) to Information Requests, IOGA referenced a modeling assessment performed by consultants for Chesapeake Energy which incorporated a number of revisions to and recommendations on the Department's modeling analysis[357]. The analysis was based on one year of Binghamton meteorological data which indicated compliance with the PM10 NAAQS and much lower PM2.5 impacts than the Department's results, but still exceedances of the PM2.5 NAAQS. Mitigation measures were listed for resolving the latter exceedances. The analysis incorporated a set of assumptions which are summarized below with the Department's position on each of these:

The PM emissions provided by ALL consultants in the Industry Information Report were not speciated with respect to PM10 and PM2.5. Based on factors in EPA's AP-42 for large uncontrolled diesel engines, the PM10 and PM2.5 emissions represent 82% and 69%, respectively, of the total PM emissions. The Department has reviewed the information and agrees that the corresponding emissions should be adjusted accordingly;

The set of 15 completion equipment engines were represented in the Department's modeling as three sets of 5 units stationed next to each other. Industry noted that since these units contributed significantly to the modeled exceedances, each of the engines should be model as a separate point source. The Department had noted this conservative step and has remodeled the units are 15 separate sources. However, unlike Chesapeake's approach of separating the 15 units in two sets at the extreme ends of the pads, the Department has no reason to believe the engines would not be placed next to each other. Thus, the engines are re-modeled as depicted in revised Figure 6.11;

[357] June 21, 2010 letter from Brad Gill of IOGA-NY to Kathleen Sanford and associated modeling files.

It is claimed that the use of ULSF would result in an additional 10% reduction in PM emissions. The Department could not readily verify the level of reduction specifically for all diesel fuel sulfur contents, but it has been considered in our discussion of resultant impacts;

It was notes that the maximum emissions provided for the completion equipment engines are only representative of two hours in the operation cycle of these units. Thus, the hourly emission rate in the modeling was "prorated" to better characterize the likely 24-hour emission rate. The Department does not agree with this approach. As noted in our previous analysis, the ALL report noted a typical hydraulic fracturing operation can require up to 10 stages of total 5 hour periods. Thus, it is likely that a relevant portion of a day could experience the maximum hourly emission rate associated with worst case impacts, as we had previously assumed. Since there is no justified or simplified approach to account for this possibility, we believe it prudent to use the maximum hourly emission rate for the revised analysis; and

It was noted that for drilling engines, the use of the EPA "capping" stack option is not appropriate since the cap is "open" when the engines are in operation. This assumption has been revised in the reassessment by using the actual stack velocities and temperatures.

Finally, the Chesapeake modeling report noted that the background levels used were the maxima observed at representative monitors and are unreasonably high. The SGEIS recognizes the conservative nature of the background levels chosen as worst case observations, but notes that more representative values can be determined in instances where such refinement is necessary. For PM2.5, the reassessment has taken a less conservative approach in accord with the Department's and EPA's modeling guidance by reviewing the monitoring data and the expected associated average values in the Marcellus Shale area. In its March 23, 2010 guidance memo[358] on PM2.5, EPA provided a screening first Tier conservative approach to addressing NAAQS compliance which was to be followed by further guidance with more refined methods.

Lacking the follow-up guidance, most states, including New York, have allowed methods more in line with Section 8.2 of EPA's Modeling Guidelines. One such approach recognized by the March 23, 2010 memo is to allow for seasonal average observed concentrations. In reviewing

[358] Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS, Stephen Page, 3/23/10.

the data at monitors in the Marcellus Shale area, especially for the latest three years, we have identified a value of 15 μg/m^3 as appropriate for the purpose of determining representative 24-hour "regional" background level. The data also indicates that more recent observations than the 2005-7 levels in the SGEIS have in general shown a downward trend. It is also noted that the modeled impacts would dominate the total impacts which are to be compared to the NAAQS. For this reason, it is deemed appropriate to use the 8th highest concentration, as the form of the NAAQS, instead of the maximum 24-hour value recommended as a first screening Tier. A conservative step was to use the 8th highest maximum from each year of meteorological data modeled since these were limited to only two years per site.

In addition to these modifications to the original PM10 and PM2.5 modeling in the SGEIS, we have incorporated industry's assertion that there would not be simultaneous drilling and hydraulic fracturing operations at a single well pad. In order to better characterize the contribution of the completion equipment engines, the drilling rig engine and the air compressors, in addition to calculating the maximum overall impacts, the modeling results were also separated for each operation to determine the need for mitigation associated with each engine type. The modeling approach was otherwise identical to the previous analysis, except the version of AERMOD was updated to the version (09292) available at the time of the analysis.

The first step in the modeling exercise was to determine the maximum 24-hour PM10 and PM2.5 impact for each of the modeled years. These results are presented in Table 6.19. It is seen that the refined impacts which incorporate the above considerations are much lower than the values in Table 6.15. This reduction is due mainly to the speciated emission rates and the modeling of completion equipment engines as individual point sources. However, the impacts are still projected to be above the PM10 and PM2.5 NAAQS, except for the PM10 impacts associated with the drilling engines. As was noted previously, these maximum impacts occur next to the well pad and concentrations drop-off relatively sharply with downwind distance. The modeled impacts were reviewed and indicate that impacts above the NAAQS-minus-background levels value occurred at distances up to a maximum of 60m for completion equipment engines and PM10, while for PM2.5 the corresponding maximum distances were 120 and 150m for the drilling and completion equipment engines, respectively. The levels of the maximum impacts also indicate that the different sets of engines could be dealt with using different mitigation measures.

As required by Part 617.11(5) (see next section for more details), the Department would pursue mitigation measures which eliminate potential adverse impacts to the maximum extent practicable. The August 26, 2009 industry report, the Industry Information Report and technical information from the public[359] identified a set of such potential measures which have been reviewed with this SEQRA requirement in mind. Certain of these suggestions would unlikely be practically implemented to any extent; for example, the use of electric engines could be very limited due to the remote nature of the drilling sites, while cleaner fuel engines are currently being investigated by engine manufacturers for future use. To the extent these alternative cleaner engines are available, the Department recommends their use. On the other hand, PM control equipment or the use of newer and cleaner engines are two measures recognized by both industry and the public as viable and the Department's review has concluded that these measures are practical. Appendix 18A provides the Department's review of the emission factors for various tiers of engines and potential after-treatment methods. Its conclusions are incorporated in the following discussions.

The discussions are limited to PM2.5 since these are the controlling impacts; that is, any measures to eliminate the PM2.5 exceedances would also assure compliance with the PM10 NAAQS. For the drilling rig and air compressor engines, the results in Table 6.19 were further analyzed to determine the impacts from each. The contribution to the overall maximum impact (Buffalo, 2007) for drilling operations was associated with the rig engines. Furthermore, industry has suggested and operational diagrams confirm that these engines are used close to the center of the well pad where the drilling actually occurs. The modeling results in Table 6.19 indicate that at a distance of 75m (from the center to the edge of the well pad) the drilling engine impacts are 30 $\mu g/m^3$, essentially due to the rig engine, which would still require mitigation when a background level of 15 $\mu g/m^3$ is used. Even if the 10% reduction in PM emissions due to the use of ULSF is achieved, as argued by industry, the resultant impact would still exceed the NAAQS. The rig engine impacts, however, are associated with ALL report's assumed Tier 1

359 For example, comments by AKRF consultants on behalf of NRDC, Memorandum from Hillel Hammer, dated December 3, 2009, page 5.

engine emission factor. If the rig engines class was restricted to the use of Tier 2 and higher, then the PM2.5 impacts would be reduced by at least a factor of 2.7 (see Table Two of Appendix 18A, 0.4/0.15) which would result in compliance with the NAAQS regardless of where these engines are located on the well pad.

Industry data in the IOGA-NY information responses indicate that a majority (71%) of engines currently in use are Tier 2 and Tier 3 engines. In addition, a small fraction (3.5%) are uncertified (Tier 0), with “unknown” emissions. It is the Department’s conclusion that these latter engines cannot be used for drilling in New York’s Marcellus Shale since it has not been demonstrated that these would result in NAAQS compliance. Furthermore, since 25% of the current drilling engines are Tier 1, their use in New York should only take place with certain control measures. The discussions in Appendix 18A conclude that of the two exhaust after-treatment measures, Diesel Oxidation Catalyst (DOC) and Continuously Regenerating Diesel Particulate Filter (CRDPF) or particulate “traps”, the latter is by far the more effective method in that it achieves almost three times the emission reduction (i.e., 85% vs 30%). The level of control achieved by the traps is necessary to alleviate all PM2.5 NAAQS exceedances from any Tier 1 drilling engines. Thus, the CRDPF traps should be the after-treatment for Tier 1 drilling engines if these are to be used in New York. This conclusion also applies to the air compressors for which the maximum PM2.5 impact is calculated to be 65ug/m^3 for Tier 1 emissions. On the other hand, Tier 2 and above drilling rig engines and air compressors demonstrate NAAQS compliance without these controls.

The Department also considered the “mitigation” of the NAAQS exceedances by stack height and distance restriction measures identified previously in the SGEIS. Although the IOGA-NY response also lists the stack height increase on the drilling engines as a potential measure, there is no indication from industry if such measures are practical given the stack configuration of these engines and the height to which these would be extended. In addition, this measure is not in strict accord with the need to mitigate the adverse impacts to the maximum extent practicable. The combination of operating these engines closer to the drilling rig, but more importantly the use of CRDPF traps on Tier 1 engines are deemed the necessary mitigation measures.

Turning next to the completion equipment engines, it seems even less practical to apply the distance and stack height increase restrictions to this class of engines. In fact, industry has previously indicated that stack height increase on these mobile units cannot be practically accomplished. A modeling run indicates that in order to meet the PM2.5 standard under the revised set of assumptions, the stack height would need to be at least doubled. Furthermore, the distance at which impacts are projected to be below the NAAQS-minus-background level was noted previously to be 150m. This is based on the Tier 2 emission factor modeled for these engines as provided by the ALL report. Consequently, the required practical approach to these engines would also require the use of the CRDPF traps as after-treatment on Tier 2 engines. For the maximum 24-hour PM2.5 case of Table 6.19 (Buffalo, 2006), the 202 $\mu g/m^3$ impact reduces to 44 $\mu g/m^3$ at a distance of 75m from the engines. Again, a 10% reduction in PM emissions due the use of ULSF does not alleviate these exceedances. Furthermore, unlike the smaller drilling engines, the ability of placing the 15 completion equipment engines (typically 14 used in Pennsylvania) near the center of the well pad is questionable. Based on industry's depiction, it is possible to separate these into two sets at either side of the hydraulic fracturing operations to further reduce impacts. In sum, however, the number of Tier 2 completion equipment engines which would require the installation of the particulate traps ranges from at least two thirds to all of the 15 engines per hydraulic fracturing job. For practical purposes, it is recommended that all Tier 2 engines be equipped with the CRDPF traps. Otherwise, each well operation might need to undergo more site specific analysis to demonstrate that a certain configuration or PM trap installation alternative would assure compliance with the 24-hour PM2.5 and PM10 NAAQS. Further details on the practicality of requiring these traps and other after-treatment control measures are discussed in the section following the SO_2 and NO_2 modeling results.

With respect to the Tier 0 and Tier 1 completion equipment engines, these emissions have not been analyzed or modeled, but for the same reasons as for the drilling engines, Tier 0 completion equipment engines should not be used in New York. In addition, based on the scaling of the maximum impact in Table 6.19 by the ratio of Tier 1 to Tier 2 emission factors (2.7), it is determined that Tier 1 engines have the potential to cause a modeled exceedance even if equipped with a particulate trap (maximum impact of 82 $\mu g/m^3$ with 85% control). Industry can suggest impact mitigation in addition to the use of PM traps in order to show compliance with the NAAQS, but lacking such a demonstration, it is the Department's interim conclusion that Tier 1 completion equipment engines should not be used in New York. On the other hand, and as also suggested by industry and the public, newer Tier 4 engines, which would likely be equipped with traps in order to achieve the required emission factors for those engines, can be used as an alternative to the Tier 2 engines with a PM trap.

B) SO_2 and NO_2 1-hour Impacts and Potential Mitigation Measures.

The 1-hour SO_2 and NO_2 NAAQS were promulgated since September 2009. Permitting and SEQRA actions after the effective date of an NAAQS are addressed by the Department to assure compliance with the NAAQS in accord with standard Department and EPA policy and requirements. EPA Region 2 recommended that the Department consider the new NAAQS in the SGEIS. In accord with the SEQRA process and the Department's Subpart 200.6 requirement, the Department has modeled the 1-hour SO_2 and NO_2 impacts to assure that all NAAQS are met.

With respect to the 1-hour SO_2 standard of 196 $\mu g/m^3$, no detailed modeling was determined necessary. Instead, the results of the previous SO_2 3-hour modeling in Table 6.15 indicated that the use of the ULSF would likely result in 1-hour impacts being below the NAAQS. Thus, the 1-hour maximum CO impact in Table 6.15 was used to scale the corresponding 1-hour maximum SO_2 impacts using the ratio of the fracturing engine SO_2 and CO emissions since these engines were responsible for the overall maxima. The resultant maximum impact is calculated to be 24 $\mu g/m^3$. Using a representative, yet conservative, maximum 1-hour SO_2 level of 126 $\mu g/m^3$ from the Elmira monitor for 2009 gives a total impact of 150 $\mu g/m^3$ which is below the corresponding NAAQS of 196 $\mu g/m^3$. Thus, no further modeling was necessary to demonstrate compliance with the 1-hour SO_2 standard.

Simple scaling to demonstrate compliance was not possible for the NO_2 1-hour impacts due to the very large concentrations projected using the same method. Instead, it was necessary to account for a number of refinements in the modeling based on EPA and Department guidelines. There are at least two main aspects to the NO_2 modeling which need to be addressed in such refinements. These issues have been raised by EPA, industry and regulatory agencies as needing further guidance. Similar to the PM2.5 guidance, EPA released a memorandum[360] on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the NO_2 NAAQS. More recently, EPA has provided further guidance [361]on particulars in the modeling approach for NO_2 1-hour NAAQS compliance determinations.

The two main issues which have been raised deal with: 1) the form of the standard, as the 3 year average of the 98% of the daily maximum 1-hour value, which the AERMOD model used for the original modeling and the revised PM2.5 modeling are not set to calculate, and 2) the ratio of NO_2 to NO_x emissions assumed for stacks from various source types. Of these, the latter is more critical since NO_2 is a small fraction of the NO_x emissions in essentially all source types and assuming all of the NO_x emissions are NO_2 is unrealistic. These issues, however, are not insurmountable. For example, there are model post processors offered by consultants which can readily resolve the first issue. At the time of our re-analysis, EPA provided the Department with a "beta" version of AERMOD which performs the correct averages for NO_2. Some limited preliminary supplemental modeling used that model version, but the Department has recalculated these impacts using the final version of AERMOD (11059) released on 4/8/11 to assure proper calculation of the 8th highest 1-hour maximum per day of meteorological data. The results discussed below reflect the use of this version of AERMOD. It should be noted that the revised version of AERMOD does not contain any changes significant enough to affect the PM2.5 analysis.

With respect to the second issue, a number of entities, including EPA and the Department, have gathered information on the NO_2 to NO_x ratios from various source types which can be incorporated in the modeling. For the specific drilling and completion equipment engines, Department staff has undertaken a review of available information and has made recommendations on this issue. The details of the recommendations are provided in Appendix 18A which are used in the analysis to be discussed shortly. In addition to this ratio, EPA and Department guidance allows the use of two methods to refine NO_2 modeled impacts; the Ozone

[360] *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program.* Memo from Stephen Page, EPA OAQPS, dated June 29, 2010.

[361] *Additional Clarifications Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS.* Memo from Tyler Fox, EPA OAQPS, dated March 1, 2011.

Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). There is no preference indicated in EPA guidance as to which method might provide more refinement. However, based on limited model evaluation results presented in the March 1, 2011 EPA guidance memorandum, the current analysis has relied upon the OLM method with the appropriate "source group" option (OLMGROUP ALL) noted in the EPA memo.

In addition to the NO_2/NO_x ratio, hourly O_3 data is necessary for the use of the method. These were taken from available Department observations at monitor sites representative of the meteorological data bases discussed in the original analysis section. Furthermore, for the determination of background 1-hour NO_2 values, we have refined EPA's first Tier screening approach of using the highest observed levels by calculating the average of the readily available 3^{rd-}highest observations from the Department's Amherst and Pinnacle State Park monitors for the year 2009. This calculated value is 50 $\mu g/m^3$ and is still conservative relative to the form of the NO_2 standard, as well as relative to further refinements allowed by EPA and Department guidance.

Appendix 18A recommends that, for engines for which emissions were calculated by the Industry Information Report and used in the Department's modeling, the NO_2 fraction of NO_x is 11% without after-treatment. Thus, an initial set of model runs were performed for the completion equipment engines using the two years of Albany data and this ratio of 0.11 in AERMOD. The results indicate that the maximum impacts from the hydraulic fracturing operations with the 0.11 factor (without the OLM approach) were approximately 3500 $\mu g/m^3$ which, although lower than those from the simple scaling of the CO impacts, are still an order of magnitude above the 1-hour standard of 188 $\mu g/m^3$ for the hydraulic fracturing operations. The impact was noted to be above the NAAQS out to a distance of 300 m from the pad. Thus, further refinements were necessary by the AERMOD-OLM approach.

First to consider, however, is that a confounding issue which this initial modeling did not include was the discovery that the NO_2 to NO_x ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of NO_2 in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher NO_2 impacts. These results clearly indicate that some form of after-treatment exhaust control method is necessary for the completion equipment engines. The after-treatment methods to reduce NO_x emissions are discussed in Appendix 18A which indicates that at present the recommended exhaust treatment method in practical use for on-road engines or engines in general is the SCR system. As noted in Appendix 18A, this preferred after-treatment method for NO_x control would reduce the NO_2 to NO_x ratio (with the CRDPF traps in place) down to essentially the same value as without the traps (i.e. 0.10). Of course, the SCR system would also substantially reduces the NO_x emissions by 90%. Therefore, the last step in the modeling of the completion equipment engines was to use the 90% reduction in emissions and the NO_2/ NO_x ratio of 0.10 with the OLM option. The analysis relied on the Tier 2 emissions provided by the Industry Information Report as the base emissions which were then reduced by 90% by the SCR controls. This level of modeling was deemed the most refinement allowed currently by Department and EPA guidance.

For the drilling engines, an initial modeling was performed first without the SCR controls and the 0.11 NO_2/NO_x ratio and the drilling rig Tier 1 emissions provided in the Industry Information Report as representative of the maximum emission case. For the compressors, Tier 2 was provided as the worst case emissions for the modeling of short term impacts. Based on two years of Albany meteorological data, it was found that the rig engines would exceed the NO_2 1-hour standard by about a factor of two and impacts would be above the NAAQS-minus-background level out to a distance of 150 m. From the modeling for PM2.5, it was found that the Tier 1 rig engines would need to be equipped with a PM trap in order to project compliance with the 24-hour PM2.5 standard. Since the traps were found to increase the NO2/ NO_x ratio by three fold, it is clear that the Tier 1 rig engine impacts would be substantially above the 1-hour NO_2 NAAQS without reductions in the NO_2 emissions. Thus, it is concluded that any Tier 1 rig engines (and compressors by analogy) would need to be equipped with both a PM trap and SCR for use in New York drilling activities.

Thus, the final set of modeling analysis used the SCR controlled Tier 2 completion equipment engine emissions with a NO_2/NO_x ratio of 0.10 and Tier 2 drilling rig engines and air compressor engines (both of which do not require PM traps) with the NO_2/ NO_x ratio set to 0.11 as noted previously. As for the completion equipment engines, the NO_2 modeling for the rig engines and compressors was based on more realistic representation of the units as individual units of five separate, but contiguous point sources as a further refinement to represent their configuration.

The emissions for each were scaled from the totals in Table 8 of the 8/26/09 Industry Report and these were placed in a north-south orientation at the same location as in Figure 6.11.

The set of NO_2 modeling with all of the meteorological data sites considered all potential sources as in previous analysis, but also provided the maximum impact for each of the three types of engines in order to determine specific potential necessary mitigation measures. However, initial modeling of the combined "drilling" scenario using two years of Albany data indicated an inconsistence in the total projected impacts in comparison to the results from the rig engines and compressors separately. This raised a potential issue with the "combined" impacts from these two operations which was related to the specifics of the OLM Ozone "distribution" approach. The resolution of this issue for the purposes of determining impacts from the rig engines and compressors and the need for potential mitigation measure was to recommend to place these two types of engines near the rig in the center of the well pad (as in the case of the PM results) and, furthermore, to separate these on either side of the drill rig to minimize combined impacts. A single year model run indicated this minimized combined impacts. From information and diagrams available, it is clear that these engines are in fact placed near the center of the pad when in actual operation.

The results of the 1-hour NO_2 impacts are presented in Table 6.19. As noted in the table, all engine are based on Tier 2 emissions, with the completion equipment engines assume to use SCR controls. The results for each of the meteorological data years, the overall maxima, the impacts at a 75-m distance (from center of pad to boundary), and the distance at which the impacts fall off to the NAAQS-background value of 138 $\mu g/m^3$ are presented for the completion equipment engines, the rig engines and the compressors. It is seen that the overall maxima are above the NAAQS. However, these need to be qualified relative to the other information tabulated in terms of potential mitigation measures necessary. It should be noted that a number of conservative assumptions are related to these impacts. First, it is noted that if the sources are placed in the center of the pad, as recommended, the impacts are much lower and essentially below the 1-hour NAAQS. Furthermore, these impacts should be adjusted downward by 10% since the tiered emission "limits" for Tier 2 and above are at most 90% NO_x as described in Appendix 18A. In addition, the background level used is conservative in that it represents the average of the third highest observations in the shale area and can be adjusted downwards.

Lastly, the distance to achieve the NAAQS minus background level is seen in the Table to be very close to the edge of the well pad. Using concentration maps for the three engine types indicate a sharp drop off of impacts such that the NAAQS minus background level is reached essentially at the well pad edge with only the 10% downward adjustment to impacts. In total, these considerations result in the NO_2 impacts being below the 1-hour NAAQS with the proper placement of the engines near the center of the well pad and the use of SCR control on the fracturing engines, coupled with Tier 2 or higher engines.

As discussed in Appendix 18A, SCR control is the only currently available NO_x reduction system for these size engines which has demonstrated the ability to practically achieve the level of reduction necessary (i.e., minimum 90%) to meet the NAAQS. Since the results of the PM2.5 modeling concluded that Tier 0 (uncertified) and Tier 1 completion equipment engines are not recommended for use in New York if CRDPF (particulate traps) are retrofitted to these, the application of SCR to Tier 2 and newer engines were considered. It is the Department's understanding from the manufacturers of these engines that the Tier 4 engines would have to be equipped with PM traps and SCR in order to meet the more stringent emission limits. It should be recalled that without the SCR control, the particulate traps increase the NO_2 to NO_x ratio by three fold and the corresponding impacts by a similar magnitude. Thus, the SCR system should be installed on all engines in which PM traps are being required for PM2.5 NAAQS compliance purposes. Any alternate system proposed by industry which has a demonstrated ability to achieve the same level of PM and NO_x reduction and, concurrently, resolve the NO_2 increase by the particulate traps in order to meet the NAAQS would be considered by the Department. At the present time, the Department is not aware of such an alternative system which has a proven record. For the purposes of the SGEIS, the Department has determined that the SCR system is necessary and adequate for this purpose. The next section discusses the practicality of using both the particulate traps and SCRs on completion equipment engines.

A summary of the Department's determination on the EPA Tier engines and the necessary mitigations to achieve the 24-hour PM2.5 and 1-hour NO_2 NAAQS is presented in tabular form in Table 6.20. The first column provides the various EPA tiers for the drilling and completion equipment engines and their time lines as presented in Appendix 18A. The next column presents sample percent of each Tier engines currently in use as provided by industry in the Information

Report. Note that based on the previous discussions, the uncertified (Tier 0) engines would not be allowed to be used in NY for Marcellus Shale activities. The third column provides the ratio of the Tier 1 emission rates for PM and NO_x to the other tiers, based on the information in Appendix 18A. The last column summarizes the determinations made by the Department on the control requirements necessary to meet the 24-hour PM2.5 (and PM10) and the 1-hour NO_2 ambient standards. As seen from the table, Tier 1 drilling engines and air compressors would require a PM trap and SCR controls, with the same controls being required on most of the completion equipment engine tiers.

Another purpose of this table is to provide an important demonstration that the Department's recommendations on control measure for these engines would result in substantial emission reduction over the current levels allowed in any other operations in other states. That is, in terms of air quality impacts, the emission reduction factor column of Table 6.20 indicates at least a factor of 3 and 2 reductions in PM2.5 and NO_2 emissions, respectively, from the Tier 1 engines. Thus, although Tier 2 and 3 drilling engines make up a majority of the engines in current use (71%), their relative emissions are much lower than the Tier 1 engines, which are recommended not to be used in NY (or have PM traps and SCR controls with about 90% reductions in emissions). Therefore, in terms of emissions reductions, the Department's requirements on the drilling engines would reduce emissions by at least half. Furthermore, since the completion equipment engines are about four times larger than the drilling engines, the imposition of PM traps and SCR on most completion equipment engines means a substantial reduction in overall PM and NO_x emissions from the set of engines to be used in New York. Any alternative emission reduction schemes which industry might further pursue would be judged against these reductions. It is clear however, that the Department would assure that any such control or mitigation measure would explicitly demonstrate compliance with the ambient air quality standards.

6.5.2.6 The Practicality of Mitigation Measures on the Completion Equipment and Drilling Engines.

The supplemental modeling assessment has concluded that in order to meet the ambient standards for the 24-hr PM2.5 and the 1-hour NO_2 NAAQS, it is necessary that the completion equipment engines tiers allowed to be used in New York to be equipped with particulate filter traps (CRDPF) and SCR control for NO_x. These are Tier 2 and newer completion equipment engines. Similarly, the Tier 1 rig engines and air compressors would be required to be equipped with both control devices if these are used in New York. The determination on the specific after-treatment controls was based on the review of available control methods used in practice (see Appendix 18A). Currently available alternative control measures considered were deemed inadequate for the purpose of achieving the level of PM2.5 and NO_x emission reductions necessary to demonstrate NAAQS compliance and/or having a proven record of use in practice.

Although industry can attempt to perform an independent assessment of alternatives to the recommended exhaust after-treatment controls, it is highly likely that a certain level of control equipment recommended would be necessary on these engines. If industry identifies viable alternative control measure which can be demonstrated to achieve the same level of emission reduction for NAAQS standard compliance, these alternative schemes would need to be submitted for Department review and concurrence prior to their use in New York. Furthermore, in recommending the use of particulate traps and the SCR technology, Department staff has considered the requirements of subsection 617.11.5 and the practicality of the chosen measures.

Taking the diesel particulate traps and the SCR controls separately, it is fair to say that since the former have a longer established history of actual use than the latter on types of engines of size in the rig engine class, the demonstration of practicality for the traps might be less onerous. For example, industry itself has identified these diesel particulate traps on Tier 2 and 3 engines in their list of mitigation measure.[362] In addition, public information (see footnote 17) also has identified the ongoing use of diesel traps as a required mitigation measure by Metropolitan Transportation Authority (MTA) for non-road engines in major construction projects in NYC. These latter engines, however, are in the size range of the smaller rig engines and not in the completion equipment engine range. Information on the ongoing practical use of particulate traps in these and similar activities have been further confirmed by Department staff through publically available information. Thus, while it can be concluded that the requirement to use particulate traps on certain EPA tiered engines is in accord with Subsection 200.6 and 617.11 of the Department's requirements, it is nonetheless necessary for industry to further assess the

[362] ALL Consulting 2010. page 43 of the ALL/IOGA September 16, 2010 Information Request Report.

practicality of their use for the completion equipment engine size range. Based on limited conversations with two of the engine manufacturers indicated that the main issue still to be resolved is the details of the engineering necessary to use PM traps as after-treatment equipment. The concern relates to the need for "stand alone" equipment for each of the completion equipment engines which differs from the built-in or add on components being currently used for the smaller on-road or off-road engines. To the Department's knowledge, currently neither PM and NO_2 control measures are being used by the gas drilling industry for other shale activities to any extent. However, it is the Department's assumption that the PM traps can be feasibly used on the Tier 1 drilling engines and compressors and the Tier 1 and 2 completion equipment engines.

For the use of SCR as the Department's preferred control measure to reduce NOx emissions from all of the completion equipment engines allowed to be used in New York, there is less information on similar size engines. As Appendix 18A notes, however, these units are widely used in a package with particulate traps on heavy duty vehicles and there is no operational reason that the same cannot be achieved with the larger completion equipment engines. One way to judge the practicality of using SCR control on these engines is to consider the costs involved. The Department has undertaken a simple approach to this issue by using the analogy to reducing exhaust stream NOx emission and its "cost effectiveness" as a means for major stationary sources to get a "waiver" from the emission control limits set forth in Subpart 227-2 (Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)). That is, if a source can demonstrate that the costs associated with the imposed emission limits are unreasonable, the Department and EPA would consider granting a waiver from meeting these limits.

Details of an analysis of the "cost effectiveness" of the SCR controls for completion equipment engines and the comparable value currently used by the Department for stationary sources is provided in Appendix 18B. It is important to note that the "cost effectiveness" is based on acceptable "engine size scaling-up" method for the completion equipment engines with certain assumptions which might not be representative of the actual cost of installation of SCR after treatment. The calculations in Appendix 18B indicate that the cost of requiring SCR on the completion equipment engines is within the value used by the Department for stationary sources and is deemed reasonable. The cost effectiveness for the smaller drilling engines should be lower. It is recognized that the applicability of 227.2 RACT requirements are meant for major individual stationary sources, but it is also to be noted that the potential annual NO_x emissions from the sum total of engine use throughout the Marcellus Shale are rather large, as discussed in the next section. Based on the conversations with the engine manufacturers, the main concern with the installation of SCR as an after-treatment control relates again to the need for a “stand-alone” system on the completion equipment engines, with the added complexity that these systems would require “continuous” maintenance to achieve the level of reduction assumed in the Department’s analysis. In addition, these discussions indicate that the cost associated with the installation of the PM traps and SCR are likely above those assumed by the Department. A calculation using the approach in Appendix 18C for PM after-treatment indicates that the “cost effectiveness” value is well above the value used for NO_x RACT waiver determinations. Thus, it is recommended that industry undertake a detailed assessment of the PM traps and SCR controls in addressing the Department’s recommendations of these controls as the required mitigation measures on certain Tier drilling and completion equipment engines in order to demonstrate compliance with the 24-hour PM2.5 and 1-hour NO_2 NAAQS.

Based on the above discussions, the Department believes that the use of particulate traps and SCR controls are reasonable and practical in achieving the mitigation of potential adverse 24-hour PM2.5 and 1-hour NO_2 impacts, respectively. As noted previously, industry can present equivalent control measures and background information for further Department considerations. Regardless of the specific measure, however, it should be made clear that the Department is required to assure compliance with ambient standards with respect to any other control measures which could put forth by industry or the public. One of the mitigation “measures” noted by industry in their Information Report, at least for NO_x emissions, is to allow for the “natural” fleet turnover of the EPA tiers as these requirements would “kick-in” over time. This suggestion is not an acceptable scheme, given that none of the engines currently in use or contemplated are the interim Tier 4 engines, which become effective in 2011, based on the Department’s knowledge and industry data. If industry is to advance such a mitigation scheme, it would submit an acceptable timeline which clearly sets out an aggressive schedule to implement the Tier 4 engines. Based on engine manufacturer’s information, there is ongoing efforts to achieve the

Tier 4 emission standards before the 2014/15 timelines noted in Table 6.20. Such an implementation schedule can be tied to the specific tiered engine after-treatment controls required by the Department.

6.5.2.7 Conclusions from the Modeling Analysis

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad and an example compressor station located next to a typical site in the area underlain by the Marcellus Shale. The analysis relied on recommended EPA and Department modeling procedures and input data assumptions. Due to the extensive area underlain by 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 area underlain by the Marcellus Shale in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were initially provided by industry and independently verified by Department 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, worst-case emission rates were developed by the Department 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 Department defined threshold levels for non-criteria pollutants. The initial modeling used limitations on simultaneous operations of the various equipment at both onsite and offsite operations for a multi-well pad 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 Information Report. It was noted that many of these exceedances 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 exceedances as one mitigation measure which could be implemented. An estimate of the distances at which the impacts would reduce to below all applicable SGCs and SGCs were provided as part of the original analysis.

Based on recent information provided by industry on the operational restrictions at the well pad, the elimination of the flowback impoundments, and a limited modeling of 24-hour PM2.5 impacts, the initial Department assessment was revisited. In addition, due to the promulgation of new 1-hour SO_2 and NO_2 NAAQS after September 2009, further modeling was performed. The significant consequences of the revised restrictions on simultaneous operations of the drilling and completion equipment engines, the number of wells to be drilled per year, and the elimination of the impoundments are incorporated in the initial modeling assessment. Further modeling details for the short term PM2.5, NO_2 and SO_2 impacts are presented in a supplemental modeling section. These results indicate the need for the imposition of certain control measures to achieve the NO_2 and PM2.5 NAAQS. These measures, along with all other restrictions reflecting industry's proposals and based on the modeling results, are detailed in Section 6.5.5 as well permit operation conditions.

Table 6.12 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → Source	SO2	NO2	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	✔	✔	✔	✔	✔	
Off-site compressors	✔	✔	✔	✔	✔	
Flowback gas flaring	✔	✔	✔	✔	✔	
Gas venting						✔
Mud-gas separator						✔
Glycol dehydrator					✔	✔

Table 6.13 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Meteorology Data Years	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 6.14 - National Ambient Air Quality Standards (NAAQS), PSD Increments & Significant Impact Levels (SILs) for Criteria Pollutants (μg/m^3)

Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2 NAAQS	196	1300		365	80
PSD Increment		512		91	20
SILs		25		5	1
PM10 NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM2.5 NAAQS				35	15
PSD Increment				9	4
SILs[363]				1.2	0.3
NO2 NAAQS	188				100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

363 The PM2.5 standards reflect the 3 year averages with the 24 hour standard being calculated as the 98th percentile value.

Table 6.15 - Maximum Background Concentration from Department 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**	Newburgh* and Belleayre	24-hour - 49 Annual - 13
PM2.5	Newburgh* and Pinnacle State Park	24-hour - 30 Annual - 11 (3 year averages per NAAQS)
CO	Loudonville	1-hour - 1714 8 hour - 1112

* Denotes the site with the higher numbers.
** For PM10, data from years 2002-4 was used.

Table 6.16 - Maximum Impacts of Criteria Pollutants for Each Meteorological Data Set

Meteorological Data Year & Location		SO_2 3-hour	SO_2 24-hour	SO_2 Annual	PM10 24-hour	PM10 Annual	PM2.5* 24-hour	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)
SO2 - 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	30***	385***	35	6.5**	9
PM2.5 - Annual	2.9	0.3	11	13.9	15	2.9	4
NO2 - 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

* SILs and increments for PM2.5 included in revised Table from EPA's final PSD rule for PM2.5

** Impacts from the off-site compressor plus the line heater only for PSD increment comparisons were recalculated for annual NO_2 and PM10 and PM2.5 24-hour cases. NA means not applicable

*** See Supplemental Modeling Section for revised analysis

Table 6.18 - Maximum Impacts of Non-Criteria Pollutants and Comparisons to SGC/AGC and New York State AAQS

Pollutant	Total Venting Emission Rate (g/s)	Impacts from all Venting Sources (µg/m^3)		All Combustion Sources and Dehydrator Impacts (µg/m^3)			
		Max 1-hr	SGC	Max 1-hr	SGC AGC	Annual	
Benzene***	0.218	140	1,300	13.2	1,300	0.90 0.10	0.13
Xylene	0.60	365	4,300	NA**	4,300	NA	100
Toluene	0.78	500	37,000	NA	37,000	NA	5,000
Hexane	9.18	5,888	43,000				
H_2S***	0.096	61.5 12.1	14*				
Formaldehyde**				4.4	30	0.20 0.04	0.06
Acetaldehyde				NA	4,500	0.06	0.45
Naphthalene				NA	7,900	NA	3.0
Propylene				NA	21,000	NA	3,000

* Denotes the New York State 1-hour standard for H_2S

** Denotes not analyzed by modeling, but the SGCs and AGCs would be met (see text)

*** AGC exceedance for benzene is eliminated by raising the dehydrator stack to 9.1m

The standard exceedance for H_2S is eliminated by using a minimum stack height of 9.1m for gas venting

The AGC exceedance for formaldehyde is eliminated by using a compressor stack height of 7.6m

Table 6.19 - Modeling Results for Short Term PM10, PM2.5 and NO_2 (New July 2011)

Met Data Location	Met Data Year	PM10, 24-hr (µg/m^3)		PM2.5, 24-hr (µg/m^3)		NO_2, 1-hour impact (µg/m^3) (see NOTE)		
		Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Rig Engine	Compressor
Albany	2007	313	76	152	36	198	256	216
	2008	268	84	129	40	198	259	230
Syracuse	2007	224	95	144	34	156	196	198
	2008	327	81	120	27	161	180	208
Binghamton	2007	281	87	154	34	194	239	208
	2008	327	89	121	35	213	231	220
Jamestown	2001	339	74	151	29	180	237	221
	2002	229	83	155	33	181	248	217
Buffalo	2006	338	106	202	55	147	269	231
	2007	318	102	189	59	148	272	231
Montgomery	2005	255	77	104	28	169	198	202
	2006	301	66	108	21	155	211	200
Maximum (µg/m^3)		339	106	202	59	213	272	231
Max @ 75m (µg/m^3)		92	75	44	30	100-140	140-170	120-150
Max Dist to NAAQS - Background (m)		60	60	150	120	<90	<100	<100

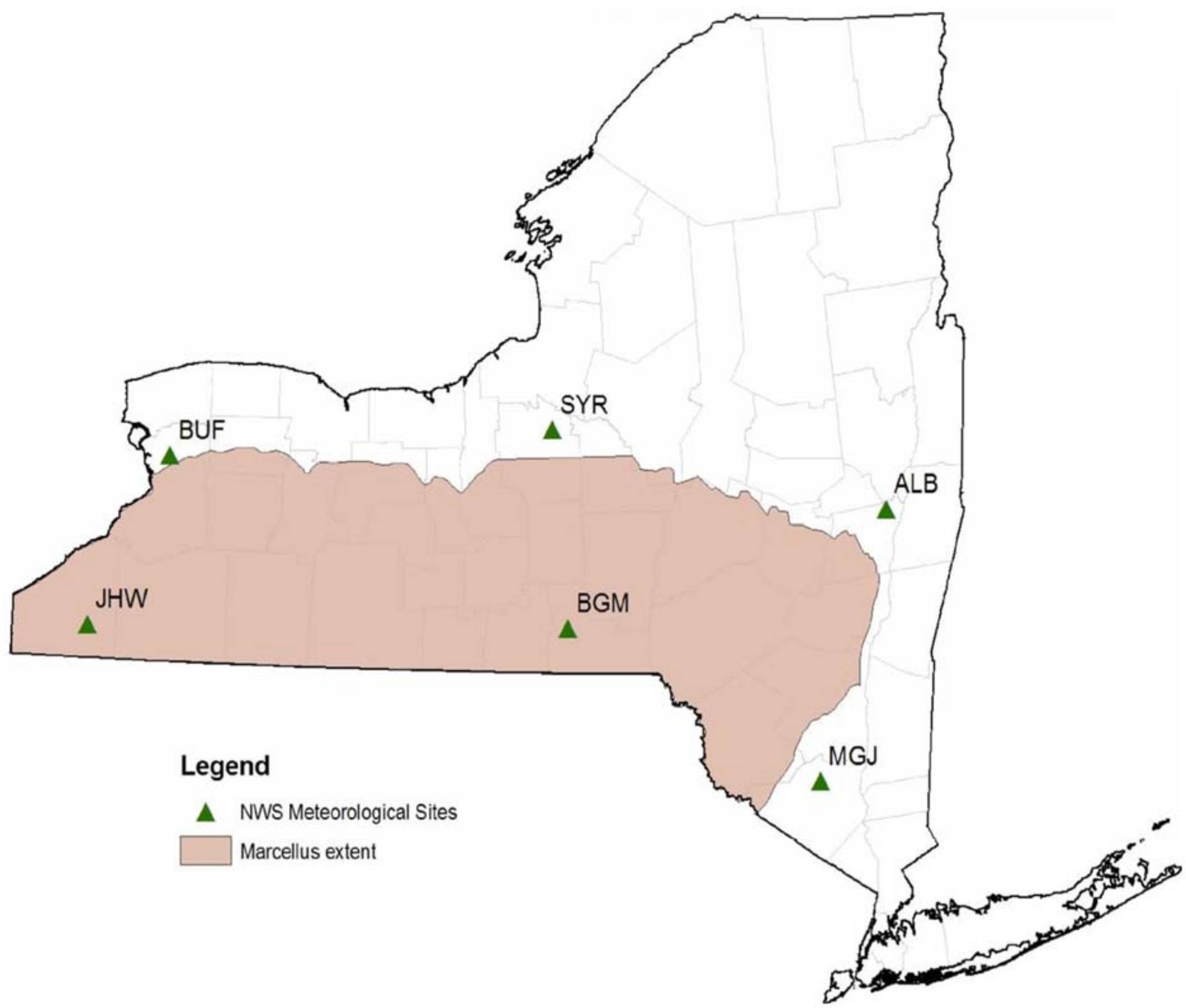
NOTE: NO_2 results reflect SCR controls on the completion equipment engines, with Tier 2 emissions used for all completion equipment, rig engines and compressors. Results are from the OLM option in AERMOD. See text for details.

Table 6.20 - Engine Tiers and Use in New York with Recommended Mitigation Controls Based on the Modeling Analysis (New July 2011)

Engine Type (year in place)	**Sample Percent in Use**	**Reduction factors in Emissions**	**Control measures considered and determined "practical" based on availability, use practice and cost.**
Drilling: Tier 1 - 1996 (five @ 500hp)	25	Others relative to Tier 1	Would need PM traps and SCR.
Drilling: Tier 2 - 2002	49	2.7 1.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 3 - 2006	22	2.7 2.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 4 - Interim (not mandated) - 2011	0	40 5.1	Would likely have PM traps built in. No SCR necessary.
Drilling: Tier 4 - 2014	0	40 23.	Would have PM traps and SCR built in.
Completion: Tier 1 - 2000 (15 @ 2250 Hp)	Assumed same as for drilling	Others relative to Tier 1	Based on modeling, propose not to allow Tier 1 engines. Alternative is traps/SCR, plus more mitigation.
Completion: Tier 2 - 2006		2.7 1.6	Would need PM trap and SCR.
Completion: Tier 4 Interim - 2011		5.3 3.5	Would likely have PM traps and SCR built in or would use in-cylinder control for PM.
Completion: Tier 4 - 2015		13 3.5	Would have PM traps and SCR built in.

Note: 3.5% of engines in use are Uncertified or Tier "0". These will not be allowed to be used in NY

Figure 6.10 - Marcellus Shale Extent Meteorological Data Sites



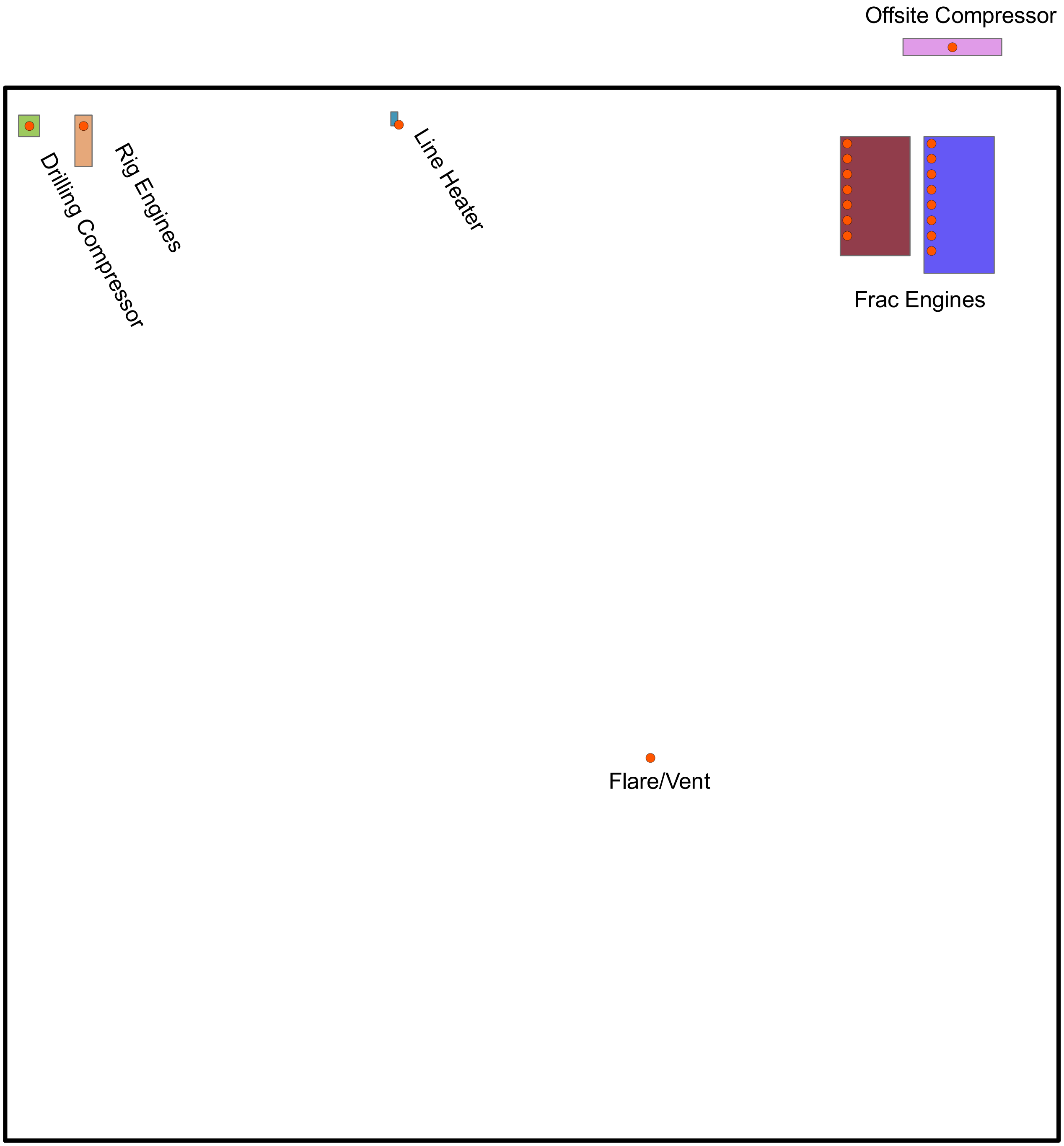


Figure 6.11- Location of Well Pad Sources of Air Pollution Used in Modeling

Buildings

- Drilling Compressor
- Frac Engines1
- Frac Engines2
- Line Heater
- Offsite Compressor
- Rig Engines

0 5 10 20 30 40 50 Meters

6.5.3 *Regional Emissions of O_3 Precursors and Their Effects on Attainment Status in the SIP*

This section addresses a remaining issue, as stressed by EPA Region 2[364] that the initial analysis did not provide a quantitative discussion of the potential regional emissions of the O_3 precursors, as contemplated in the Final Scoping for the 2009 draft SGEIS. The specific items relate to the impact of these drilling operations on the SIP for O_3 nonattainment purposes, as well as the impact of cumulative emissions from both stationary and mobile sources.

The initial analysis lacked information on the regional emissions of the cumulative well drilling activities in the whole of Marcellus Shale due to the lack of detail from industry on the likely number of wells to be drilled annually and associated emissions. It was determined that information and available data from similar shale development areas would not be suitable for a calculation of these emissions due to a variety of factors. Thus, the Department requested this emission information from industry and received the necessary data in the ALL/IOGA-NY Information Report referenced previously and in a follow-up request for mileage data for on-road truck traffic, as discussed below. The following narrative is intended to address concerns with the regional emissions as these relate to ozone attainment and similar SIP issues.

Attainment Status and Current Air Quality

The most recent nonattainment areas that have been designated by EPA are those for the 1997 8-hour ozone of 0.08 ppm (effectively 84 ppb), 1-hour ozone (0.12 ppm), annual and the 24-hour PM2.5 national ambient air quality standards (NAAQS) of 15 and 35 $\mu g/m^3$, respectively. In March 2008, EPA promulgated a revision of the 8-hour ozone NAAQS by setting the standard as 0.075 ppm. Nonattainment areas for the new standard have not as yet been established due to current efforts by EPA to reconsider a more restrictive NAAQS. EPA proposed its reconsideration of the 2008 ozone NAAQS in January 2010 taking comment on lowering the NAAQS to between 0.060 ppm and 0.070 ppm. EPA is expected to complete its reconsideration in July 2011.

Ozone and particulate matter are two of six pollutants regulated under the CAA as “criteria pollutants.” Data from Department monitors through 2010 indicate that monitored air concentrations in the established nonattainment areas for O_3 and PM2.5, as well as in the area

[364] Comments of EPA Region 2 in letter from John Filippelli dated (12/30/09), pages 2-3.

underlain by the Marcellus Shale, do not exceed the currently applicable NAAQS. In addition, there are no areas in New York State that are classified as nonattainment for the remaining four criteria pollutants: CO, lead, NO_2 and SO_2. EPA has recently promulgated revisions to the lead, SO_2 and NO_2 NAAQS and has established new monitoring requirements for the lead and NO_2 NAAQS, as well as new modeling requirements for the SO_2 NAAQS. As a result of these new requirements, the Department cannot yet determine whether ambient air quality complies with these NAAQS values. However, the Department has proposed to EPA to classify the whole state as "unclassifiable" with respect to the NO_2 1-hour NAAQS and would have to submit a recommendation to EPA on SO_2 1-hour NAAQS. As data becomes available in the next few years, the Department would assess the data and recommend to EPA designation of all areas in the State as either attainment or nonattainment.

For O_3, the Department has a wealth of information to compare against the current, but delayed, 2008 NAAQS and the range of the reconsidered NAAQS. Under the 2008 Ozone NAAQS, current air quality in the Poughkeepsie-Newburgh, NYC and Jamestown metropolitan areas would make these areas nonattainment. If the O_3 NAAQS is set at the lower values proposed by EPA, more areas of the state, including those in the Marcellus Shale play, would also be nonattainment.

State Implementation Plans

The process by which states meet their obligations to improve air quality under the CAA, (for example, the applicable NAAQS for criteria pollutants) is established in SIPs. A major component of SIPs is the establishment of emission reduction requirements through the promulgation of new regulatory requirements that work to achieve those reductions. The combined effect of both state and federal requirements is to reduce the level of pollutants in the air and bring each nonattainment area into attainment. These requirements, which apply to both stationary and mobile sources, apply to both new and existing sources and are intended to limit emissions to a level that would not result in an exceedance of a NAAQS, thus preserving the attainment status of that area. In order to judge the potential effects of the projected O_3 and PM2.5 precursors in the Marcellus Shale on the SIP process, the Department has looked at the level of these emissions relative to the baseline emissions and has come to certain conclusions on the approach necessary to assure the goal of NAAQS compliance.

Projected Emissions and Current/Potential Control Measures

The primary contributors (emission sources) to ozone pollution include those that emit compounds known as "precursors" that result in the formation of ozone. The two most important precursors are NO_x and VOCs. PM2.5, another pollutant, is also directly emitted or formed from precursors, such as ammonia, sulfur oxides and NO_x. New York State and the federal government have promulgated emission rules that apply to the sources of these pollutants in order to protect air quality and prevent exceedances of the ambient air standards. In the case of Marcellus Shale gas resource development, most emissions resulting from natural gas well production activities are expected to come from the operation of internal combustion non-road engines used in drilling and hydraulic fracturing, as well as engines that provide the power for gas compression. Additional associated emissions occur with on road truck traffic used for transportation of equipment and hydraulic fracturing fluid components.

Engine emissions have long been known to be a significant source of air pollution. As a result, control requirements for these sources have been in place for many years, and have been updated as engine technology and control methods have improved. Regulations and limits exist on both the federal and state level, and effectively mitigate the effect of cumulative emissions on air quality and the SIP. In New York, these measures include:

Particulate Matter

Locomotive Engines and Marine Compression-Ignition Engines Final Rule

Heavy Duty Diesel (2007) Engine Standard

Part 227: Stationary Combustion Installations

Sulfur

Federal Nonroad Diesel Rule

6 NYCRR Part 225: Fuel Composition and Use

NO_x & VOCs

Part 217: Motor Vehicle Emissions

Part 218: Emission Standards for Motor Vehicles and Motor Vehicle Engines

Part 248: New York State Diesel Emissions Reduction Act (DERA)

Small Spark-Ignition Engines

Federal On-board Vapor Recovery

In addition, to address mobile sources emissions which might occur due to diesel trucks idling during the drilling operations, Subpart 217-3 of the New York State ECL specifically addresses this issue by limiting heavy duty vehicle idling to less than five consecutive minutes when the heavy duty vehicle is not in motion, except as otherwise permitted. Enforcement of this regulation is performed by Department Conservation Officers and violation can result in a substantial fine.

The above requirements for stationary sources apply statewide and not just in nonattainment areas due to New York's status as part of an Ozone Transport Region state. This differs from other areas such as the Barnett Shale project in which different standards apply inside and outside of the Dallas/Fort Worth nonattainment area. Furthermore, additional requirements and potential controls specific to the operations for the Marcellus Shale gas development were addressed in Section 6.5.1 with respect to the well pad and the compressor station (e.g., NSPS and NESHAPs requirements per 40 CFR 60, subpart ZZZZ and Part 63, subpart HH). Certain of these measures restrict the emissions of O_3 precursors to the maximum extent possible with current control measure. In addition to the mandatory requirements that are in place as a result of the above rules that directly affect the types of emissions that are expected with the development of Marcellus Shale gas resources, there are a number of other recommended measures that have been incorporated in previous sections to further reduce the emissions associated with these operations and mitigate the cumulative impacts:

1. NO_x emission controls (i.e., SCRs) and particulate traps on all diesel completion equipment engines and on older tier drilling engines (see section 6.5.2);

2. Condensate and oil storage tanks should be equipped with vapor recovery units (see section 6.5.1.5); and

3. The institution of a fugitive control program to prevent leaks from valves, tanks, lines and other pressurized production operations and equipment (see section on greenhouse gas remediation).

Use of controls for excess gas releases, such as flares by REC should be implemented wherever practicable (see section 6.5.2). In addition, other measures such as the use of more modern equipment and electric motors instead of diesel engines, where available, are recommended.

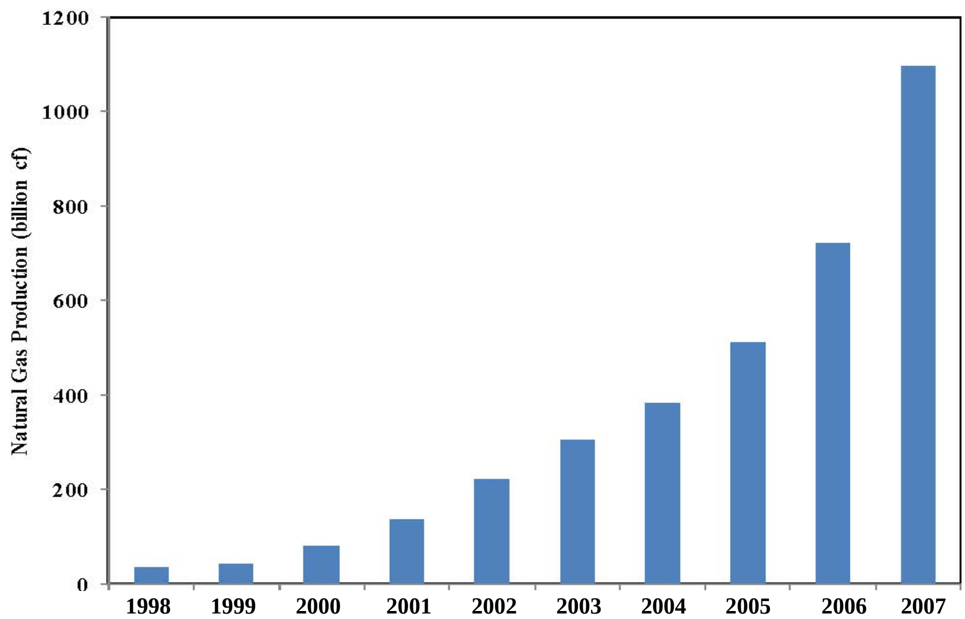
Regional NO_x and VOC Emission Estimates and Comparison to Estimates from another Gas-Producing Region

In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from the Barnett Shale formation of north Texas, which has undergone extensive development of its oil and gas resources, was reviewed. The examination of the development of the Barnett Shale could be instructive in developing an approach to emissions control and mitigation efforts for the Marcellus Shale. As a result, the Department has examined one commonly referenced study and source of information on the regulation and control of air pollution from the development of the Barnett Shale.

First, the development of the gas resources of the Marcellus Shale, as with the Barnett Shale, not be spatially distributed evenly across the geographic extent of the region, but would likely concentrate in different areas at different times, depending on many factors and limitations, including the price of natural gas at any given moment, the ease of drilling one area versus another, and other legal/environmental constraints such as potential drilling in watersheds. As such, industry cannot project at this time as to where impacts may concentrate regionally within the Marcellus Shale region. Furthermore, well development would occur over time, wherein initially there would be a "ramping-up" period, followed by a nominal "peak" drilling period, and then a leveling off or dropping off period. Some of these factors and caveats are discussed in the ALL/IOGA-NY Information Report.

Thus, the cumulative impacts of gas well drilling within the Marcellus Shale would also vary depending on what point in time those impacts are measured as the development of the gas resource expands over time. As an example of how well development proceeded in the Barnett Shale, the Figure 6.12 indicates that gas production rose dramatically from 1998-2007. This chart is being used by the Department for illustration purposes only to indicate the timeframes which might be involved in the Marcellus development and not as an actual indication of expected development. Preliminary information from Pennsylvania indicates a more rapid increase in gas well drilling and production.

Figure 6.12 - Barnett Shale Natural Gas Production Trend, 1998-2007[365]



As drilling activities “ramp up,” the potential for greater environmental impacts likewise increase. In estimating the air emissions of drilling in the Marcellus Shale, a worst case (conservative) scenario of drilling and development was developed by IOGA-NY in response to an information request from the Department. The estimates are provided in the ALL/IOGA-NY Information Report. There are a number of caveats associated with these estimates so the absolute magnitudes of emissions should be interpreted accordingly. However, an estimate of worst case emissions are projected for the maximum likely number of wells (2216) to be drilled in the Marcellus Shale for the “peak” year of operations and the emission factors and duration of operations provided in the previous industry report (8/26/09) used in the modeling assessment.

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[365] Taken from Armendariz (SMU), 2009, p. 2.

Some of the factors which were included in the estimates noted in the ALL/IOGA-NY Information Report include:

- Average emission rates for dry gas are used for every well for every phase of development;
- Maximum number of wells (both horizontal and vertical) in any year;
- No credit is taken for any mitigation measures, permit emissions controls, or state and federal regulatory requirements that are expected to reduce these estimates;
- Drilling emissions are conservatively estimated at 25 days for the horizontal wells;
- Heater emissions are included year-round in the production estimates; however, they would be seasonal and would take place during the non-ozone season;
- Off-pad compressor emissions are included in the production estimates; however, it is anticipated that most well pads would not include a compressor;
- No credit is taken for the rolling nature of development; i.e., that all wells would not be drilled or completed at the same time, on the same pad;
- No credit is taken for improved nonroad engine performance and resultant reduced NO_x emissions from the higher tier engines that would be phased in over time; and
- No credit is taken for reduced emission completions which would significantly reduce flaring and hence related NO_x and VOC emissions.

The ALL/IOGA-NY Industry Information Report predicted the ozone precursor emissions depicted in Table 6.21.

Table 6.21 - Predicted Ozone Precursor Emissions (Tpy)

	Drilling	**Completion**	**Production**	**Totals**
Horizontal - NO_x	8,376	5,903	8,347	22,626
Vertical - NO_x	409	345	927	1,681
Total NO_x	8,785	6,248	9,274	24,307
Horizontal - VOC	352	846	5,377	6,575
Vertical - VOC	17	81	597	695
Total VOC	369	927	5,974	7,270

It is seen that the total for NO_x emissions for the horizontal wells is made up of 37% each from drilling and production and 26% from completion. It is to be noted that for the latter emissions, about half is associated with potential flaring operations. For VOC emissions for the horizontal wells, the production sources dominate (82% of total). This is related to the dehydrator emissions assumed to operate for a full year. It is also noted that the completion VOC emissions are due to venting and flaring. Based on the above numbers, IOGA-NY concluded the impact from the development of the Marcellus at a worst-case peak development rate would add 3.7% to existing NO_x emissions on a statewide basis. This was based on the 2002 baseline emission inventory (EI) year used in New York's 2007 SIP demonstration for the 8-hr ozone standard[366]. A more germane comparison would be to the "upstate" area emissions where Marcellus Shale area is located. This comparative increase would be 10.4% for the same EI year. These upstate area emissions exclude the nine-county New York ozone nonattainment area, as well as the counties north and east of the area underlain by the Marcellus Shale.

The total NO_x emissions increase from this example is deemed significant, but does not account for the number of mitigation measures imposed and recommended in the revised SGEIS. For example, the use of SCR control to reduce NO_x emissions by 90% from the completion equipment engines would reduce the completion emission by about half, while the minimization of flaring operations by the use of REC would reduce the rest of these completion emissions down to a very small value which would significantly reduced the relative percentage. In addition, as noted by the IOGA-NY Information Report, the production sources used in the estimates of NO_x emissions are not likely to be used the full year and might not be even needed at many wells. Furthermore, the estimated drilling emissions assume the maximum number of days would be needed for each well and the associated use of older tier engines throughout the area and over the long-term. Thus, the relative percent of Marcellus well drilling emissions to the existing baseline is highly likely to be substantially less than the value above using the worst case estimates.

The IOGA-NY also concluded that the total VOC emissions of 7,270 Tpy from the development of the Marcellus Shale would add 0.54% to existing VOC emissions on a statewide basis. Using

[366] Ozone Attainment Demonstration for NY Metro Area - Final Proposed Revision, Appendix B, pp. 10-11 http://www.dec.ny.gov/chemical/37012.html.

the same baseline EI year as for NO_x, the relative increase for VOCs would be 1.3%. This increase is deemed small and also does not account for recommended mitigation measures such as the minimization of gas venting by REC.

The above NO_x and VOC relative emission comparisons do not include the contribution from the on road truck traffic associated with Marcellus Shale operations and which had to be estimated by the Department. The ALL/IOGA-NY Information Report included the light and heavy truck trips, but not the associated average mileage which is necessary to calculate emissions. Thus, the Department requested an average Vehicle Miles Traveled (VMT) for the two truck types and ALL Consulting provided the data in a response letter.[367] Based on this information, the Department projected the NO_x and VOC emissions from on road truck as discussed in the next subsection.

Effects of Increased Truck Traffic on Emissions

The initial modeling analysis did not address on-road mobile source emissions resulting from the drilling operations, specifically, diesel truck emissions, except at the well pad. The Department has analyzed the impact of increased emissions from truck traffic in the Marcellus Shale affected counties. As part of this analysis, the Department utilized estimates of VMT provided by ALL Consulting/IOGA-NY in response to the Department's information request to determine the environmental impacts of project related truck emissions. Industry estimated that the weighted average one way VMT for both light and heavy duty trucks to be approximately 20 to 25 miles for both horizontal and vertical wells.

The Department used these estimated average VMT for heavy-duty and light-duty trucks and the number of truck trips contained in the ALL/IOGANY Information Report to calculate the total additional VMT associated with drilling activities. These VMT, along with other existing New York-specific data were input to the EPA's Motor Vehicle Emission Simulator (MOVES) model to estimate NO_x and VOC emissions for the various truck activities. EPA Region 2 commented on the SGEIS and requested the use of the MOVES model. As EPA's approved mobile source model, MOVES incorporates revised EPA emission factors for various on-road mobile source activities and associated pollutants. The resulting emissions support a comparison of how traffic

[367] All Consulting letter of March 16, 2011 from Daniel Arthur to Brad Gill of IOGANY.

directly related to the drilling operations impacts the overall mobile emissions that normally would occur throughout the Marcellus Shale drilling area.

The estimated emissions of NO_x and VOCs (and well as other pollutants) that result from the additional light and heavy duty truck traffic expected with Marcellus well drilling are detailed in Appendix 18C. The emissions for the counties in the area underlain by the Marcellus Shale are presented for both the existing baseline activities as well as those associated with the drilling activities. In addition, the absolute and percent differences which represent the additional truck emissions are shown.

The results show that the total NO_x and VOC emissions are estimated to be 687 and 70 Tpy, respectively, and are expected to increase the existing baseline emissions by 0.66% and 0.17%. The maximum increase for any pollutant is 0.8%. These increases are deemed very small. In addition, the traffic related NO_x and VOC emissions are noted to be small fractions of the corresponding increased emissions due to other activities associated with gas drilling, as summarized in the last subsection. For example, the traffic related NO_x emissions are about 3% of the total NO_x emissions given in the above mentioned summary table. A simple estimate of traffic related emissions of PM2.5 per pad, using the total emissions and the number of maximum wells is shown in Appendix 18C to be 0.01 Tpy which is comparable to the previously estimated pad specific PM2.5 emissions noted in the modeling section which was estimated with the EPA MOBILE6 model.

Based on these results, the Department concluded that the estimated truck related emissions would be captured during the standard development of the mobile inventories for the SIP. These estimates are also noted to be within the variability associated with the MOVES model inputs.

Comparison to Barnett Shale Emission

A referenced report[368] on the Barnett Shale oil and gas production prepared by Southern Methodist University (SMU) for the Environmental Defense Fund (EDF) has been noted as a source of emission calculation schemes and resultant regional emissions for that region of Texas. In terms of the projected emissions of NO_x and VOCs, while caution should be exercised in

[368] Armendariz (SMU), 2009.

making comparisons between the two areas, a picture of emissions from the Barnett Shale may be a useful point of departure for understanding the magnitude and types of emissions to be expected with the development of the Marcellus Shale. The Department has not undertaken a review of the rationale or the methodologies used in the SMU report and is also aware of the Texas Commission on Environmental Quality (TCEQ)'s critique of the report.[369] Since the report, TCEQ has undertaken a detailed emission inventory development program to better characterize the sources and to quantify the corresponding emissions.

For the present purposes, it is necessary to provide a brief outline of the potential differences between the gas development activities and associated sources between the Barnett report and the industry projections for the Marcellus Shale. For example, the SMU report provided the relative amount of emissions from different source categories and corresponding NO_x and VOC emissions, as presented in Table 6.22 below. For comparison, the industry-provided emissions summarized above are 66.7 and 20 tons per day (Tpd) for NO_x and VOCs, respectively. However, the latter do not include some of the sources tabulated in the SMU report such that a straightforward comparison is not possible. Nonetheless, the SMU report notes that the largest group of VOC sources was condensate tank vents. Table 6.22 also indicates that fugitive emissions from production operations have a significant contribution to the VOC totals.

Table 6.22 - Barnett Shale Annual Average Emissions from All Sources[370]

Source	2007 Pollutants, Tons per day(Tpd)		2009 Pollutants, Tons per day (Tpd)	
	NOx	VOC	NOx	VOC
Compressor Engine Exhausts	51	15	46	19
Condensate And Oil Tanks	0	19	0	30
Production Fugitives	0	17	0	26
Well Drilling and Completion	5.5	21	5.5	21
Gas Processing	0	10	0	15
Transmission Fugitives	0	18	0	28
Total Daily Emissions (Tpd)	**56**	**100**	**51**	**139**

370 Adapted from Armendariz (SMU), 2009 p. 24.

These might explain the differences in VOC emissions in that industry does not expect to use condensate tanks in New York due to the dry gas encountered in the Marcellus Shale. In addition, these tank emissions, if used, would be controlled by vapor recovery systems as noted in Section 6.5.2. In addition, all efforts would need to be made by industry to minimize fugitive emissions as recommended in the greenhouse gas emission mitigations section which would reduce concomitant VOC emissions.

The SMU report also provides charts which compare the total NO_x plus VOC emissions from the Barnett oil and gas sources to totals from on-road source categories in the Dallas-Fort Worth area, concluding that the former are larger than the on road emissions in some respects. However, these comparisons are not transferrable to the Marcellus Shale situation in New York not only because VOC emissions dominate these totals, but also since the comparisons are to a specific regional mix of sources not representative of the situation to be encountered in New York. On face value, the absolute magnitude of these total emissions is much larger than even a "worst-case" scenario for the Marcellus Shale.

Again, no firm predictions or projections can be made at this time as to where or when gas drilling impacts may concentrate regionally within the Marcellus Shale, but the Department would continue to avail itself of the knowledge and lessons learned from similar regional shale gas development projects in other parts of the country.

Further Discussions and Conclusions

There are stringent regulatory controls already in place for controlling emissions from stationary and mobile sources in New York. With additional required emission controls recommended in the revised SGEIS for the operations associated with drilling activities, coupled with potential deployment of further emission controls arising from upcoming O_3 SIP implementation actions, the Department is confident that the effect of cumulative impacts from the development of gas resources in the multi-county area underlain by the Marcellus Shale would be adequately mitigated. Thus, the Department would be able to continue to meet attainment goals that it has set forth in cooperation with EPA. In addition to eliminating the use of uncertified and certain older tier engines and requiring specific mitigation measures to substantially reduce PM and NO_x emissions in order to meet NAAQS, the Department would review the need for certain additional mitigation prior to finalizing the SGEIS. As part of the information, the Department is seeking from industry an implementation timeline to expedite the use of higher tier drilling and completion equipment engines in New York. Furthermore, as the Department readies for the soon to be announced revised O_3 NAAQS and potential revisions to the PM2.5 NAAQS, the need for imposing further controls on drilling engines not being currently required to be equipped with PM traps and SCR would be revisited. If it is determined that further mitigation is necessary, further controls would be required. The review would consider the relatively high contribution to regional emissions of NO_x from the drilling engines and result from regional modeling of O_3 precursors which would be performed in preparation of the Ozone SIP.

Regional photochemical air quality modeling is a standard tool used to project the consequences of regional emission strategies for the SIP. The application of these models is very time and resource intensive. For example, these require detailed information on the spatial distribution of the emissions of various species of pollutants from not only New York sources, but from those in neighboring states in order to properly determine impacts of NO_x and VOC precursor emissions on regional O_3 levels. At present, detailed necessary information for the proper applications of this modeling exercise is lacking. However, as part of its commitment to the EPA, and in cooperation with the Ozone Transport Commission to consider future year emission strategies for the Ozone SIP, the Department would include the emissions from Marcellus Shale operations in subsequent SIP modeling scenarios. As such, properly quantified emissions specifically resulting from Marcellus Shale operations would be included in future SIP inventories to the extent that the information becomes available. Interim to this detailed modeling, the Department would perform a screening level regional modeling exercise by adding the projected emissions associated with New York's portion of the Marcellus Shale drilling to the baseline inventory which is currently being finalized. This modeling would guide the Department's finalization of the SGEIS. In addition to the availability of the regional modeling results, the Department has recommended that a monitoring program be undertaken by industry to address both regional and local air quality concerns as discussed in the next section.

6.5.4 Air Quality Monitoring Requirements for Marcellus Shale Activities

In order to fully address potential for adverse air quality impacts beyond those analyzed in the SGEIS relate to associated activities which are either not fully known at this time or verifiable by

the assessments to date, it has been determined that a monitoring program would be undertaken. For example, the consequences of the increased regional NO_x and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions, including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable. Thus, it has been determined that an air monitoring plan is necessary to address these regional concerns as well as to verify the local-scale impact of emissions from the three phases of gas field development: drilling, completion and production. The monitoring plan discussed herein is determined to be the level of effort necessary to assure that the overall activities of the gas drilling in the Marcellus Shale would not cause adverse regional or local air quality impacts. The monitoring is an integral component of the requirements for industry to undertake to satisfy the SEQRA findings of acceptable air quality levels.

Based on the results from the Department's assessments of gas production emissions, and in consideration of the well permitting approach and the modeling analysis, an air monitoring plan has been developed to address the level of effort necessary to determine and distinguish both background and drilling related concentrations of pertinent pollutants. In addition, a review of previous monitoring activities for shale drilling conducted by the TCEQ[371] and the PADEP[372] was undertaken to better characterize the monitoring needs and instrumentation. The approach selected as best suited for monitoring for New York Marcellus Shale activities combines a regional and local scale monitoring effort aimed at different aspects of emission impact characterization. These two efforts are as follows:

371 See: http://www.bseec.org/content/tceq-full-review-armendariz-study-barnett-shale-pollution.

372 See: http://www.dep.state.pa.us/dep/deputate/airwaste/aq/toxics/toxics.htm.

1) Regional level monitoring: In order to assess the impact of regional emissions of precursors including VOCs and NO_x, monitoring for O_3 and PM2.5 would need to be conducted at two locations. One would be a “background” site and another would need to be placed at a downwind location sited to reflect the likely impact area from the atmospheric transport and conversion of the precursors into secondary pollutants. These would enhance the current Department O_3 monitoring in the area. These sites would also need to be equipped with air toxics monitors so that pollutant levels can be compared to each other and to other existing sites; and

2) Near-field/local scale monitoring at various locations in the Marcellus Shale: This monitoring can be intermittent but would be carried out in areas expected to be directly impacted by one or more wells and compressor stations. The data from this monitoring effort would be used to assess the significance of the various known drilling related activities and to identify specific pollutants that may pose a concern. In addition, possible fugitive emissions of certain VOCs should be monitored to locate and mitigate emissions, beyond those necessary for worker safety purposes. The Department has identified specific well drilling activities and pollutants which have been found to be related to these activities and recommends that these are included in the near-field monitoring program See Table 6.23.

Table 6.23 - Near-Field Pollutants of Concern for Inclusion in the Near-Field Monitoring Program (New July 2011)

Well Pad and Related Activity	Pollutants of Concern
Drilling and Completing (completion equipment) Engines	1-Hour NO_2 and 24-hour PM2.5
Gas venting (could be potentially mitigated by REC)	BTEX, formaldehyde, H_2S or another odorant.
Glycol dehydrator and condensate tanks at either the well pad or at the compressor station (if wet gas is present)	BTEX, benzene, and formaldehyde.
Leaks and fugitives	Methane and VOC emissions

The near-field local scale monitoring is expected to be performed periodically with field campaigns typically lasting a few days when activities are occurring at the well pad and when the compressor station is operational and operating near maximum gas flow conditions. Since the scope of gas related emissions from one area of operation to another is limited, it is anticipated that after a few intensive near-field monitoring campaigns, adequate and representative data would be gathered to understand the potential impacts of the various phases of gas drilling and production. At that point, the level of effort and the further need for the short term monitoring would be evaluated. In addition to the near-field monitoring, it is anticipated that a similar level of short term monitoring would be conducted on a limited basis at a nearby residential location or in a representative community setting to determine the actual exposure to the public.

However, based on the results from the TCEQ and PADEP monitoring, the potential for finding relatively higher concentrations would likely be in close proximity to the well pad and compressor station.

It is expected that the cost and implementation of this monitoring would be the responsibility of industry. To carry out this monitoring plan, a specific set of monitoring equipment and procedures would be necessary. Some of these deviate from the "traditional" compliance oriented monitoring plans; for example, due to the relatively short term and intensive monitoring required at various locations of activities, the suggested approach would be to operate a mobile equipped unit. Department monitoring staff has longstanding expertise in conducting this type of monitoring over the last two decades. The most recent local-scale monitoring project carried out by the Department was the Tonawanda Community Air Quality Monitoring project.

As an alternative to industry implementing this monitoring plan in a repetitive company by company stepwise fashion as gas development progresses, it is the Department 's preference that the monitoring be undertaken by the Department's Division of Air Resources monitoring staff. However, this alternative cannot be carried out with current Department staff or equipment and would only be possible with additional staff and equipment resources. This alternative is preferred from a number of standpoints, including:

1) Overall program cost would be reduced because each operator would not be responsible for their own monitoring program. Even if the operators are able to hire a common consultant, there would be complexities in allocation the work to various locations;

2) The Department would not have to "oversee" contractor work hired either by industry or by the Department;

3) The timing and production of data analysis would be simplified and reports would be under the Department's control;

4) The Department can utilize certain existing monitor sites for the regional monitoring program;

5) The central coordination would minimize the overall costs of the monitoring; and

6) The Department would have the ability to monitor near the compressor stations which might not be within the control of the drilling operators.

If the Department was to receive the necessary funding and staff to conduct the monitoring, the following table identifies some of the specifics associated with the expected level of monitoring.

Table 6.24 - Department Air Quality Monitoring Requirements for Marcellus Shale Activities (New July 2011)

Monitoring Parameters	**Purpose of Monitoring**	**Proposed Scheme and Instrumentation Needs.**
Regional scale O_3, PM2.5, NO_2 and add toxics.	To assess the impact of regional VOC and NO_x emissions on Ozone and PM2.5 levels.	Add a Department monitoring trailer to a new site in Binghamton, plus add toxics at existing Pinnacle site and the new site.
Local/near field monitoring for BTEX, methane, formaldehyde, sulfur (plus O_3, PM2.5 and NO_2)	To assess impacts close-by to well pads, compressor stations and associated equipment (e.g. glycol dehydrator, condensate tanks). Also, limited follow- up in nearby communities.	Purpose-built vehicle with generators as a mobile laboratory. A less desirable alternative is a “stationary” trailer which would need days for initialization.
Intermittent methane and VOC leaks from sources (e.g. fugitive)	To detect and initiate company mitigation of fugitive leaks.	Forward Looking Infrared (FLIR) cameras- one for routine inspections, second to respond to complaints.
“Saturated” BTEX and other VOC species monitoring	To verify the spatial extent of the mobile monitoring results.	Manually operated canister samplers which can be analyzed for 1 to 24-hour concentrations of various toxics.

This monitoring would be the minimum level of effort necessary to properly characterize the air quality in the affected areas for the pollutants which have been identified as possibly requiring mitigation measures or having an effect due to regional emissions. In developing the monitoring approach, Department staff has reviewed the results of the monitoring conducted by TCEQ and PADEP to learn from their experiences, as well as from our own toxics monitoring experiences. To that end, it was determined that a mobile unit with the necessary equipment which would best perform the monitoring for both near-field and representative community based areas. The use of an open path Fourier-transform Infrared (FTIR) spectroscopy used in the PADEP study was evaluated, but deemed unnecessary due to the fact that the mobile unit would be detecting the same pollutants at lower more health relevant detection levels. To overcome the potential concern with spatial representativeness of the near-field monitoring program, the Department recommends augmenting the mobile vehicle with manually placed canisters which could be used on a limited basis to provide a wider areal coverage during the various activities and as a secondary confirmation of the mobile unit results.

The monitoring plan outlined above would be used to address public concerns with the actual pollutant levels in the areas undergoing drilling activities. In addition, it could assist in the identification of the level of conservatism used in the emission estimates for the well pads, the Marcellus area region, and modeling analysis which have been noted as concerns.

6.5.5 Permitting Approach to the Well Pad and Compressor Station Operations

The discussions in subsection 6.5.1.8 of the regulatory applicability section outline the approach which the Department has determined is in line with regulatory permitting requirements and which best address the issues surrounding the air permitting of the three phases of gas drilling, completion and production. The use of the compressor station air permit application process to determine the regulatory disposition and necessary control measures on a case-by-case basis is in keeping with the approach taken throughout the country, as affirmed by EPA in a number of instances. This review process would allow the proper determination of the applicable regulations to both the compressor station and all associated well operations in defining the facility to which the requirements should apply. In concert with the strict operational restrictions determined in the modeling section necessary for the drilling and completion equipment engines, the self-imposed operational and emission limits put forth by industry would assure compliance with all applicable standards. To further assure that these restrictions are adhered to for all well operations, a set of necessary conditions identified in Section 7.5.3 and Appendix 10 will be included in DMN well permits.

DMN Well Drilling Permit Process Requirements

Based on industry's self-imposed limitations on operations and the Department's determination of conditions necessary to avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, mitigation noted in Chapter 7 would be imposed in the well permitting process.

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*.[373] The policy reflected in the guide is used by Department staff in reviewing an environmental impact statement (EIS) when the Department is the lead agency under SEQRA and energy use or 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.

SEQRA 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, SEQRA 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 would minimize emissions of GHGs would 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

[373] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

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.[374]

The goal of this analysis is to characterize and present an estimate of GHG emissions for the siting, drilling and completion of 1) single vertical well, 2) single horizontal well, 3) four-well pad (i.e., four horizontal wells at the same site), and respective first-year and post first-year emissions of 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.

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.[375] Human activities result in emissions of four principal GHGs: 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 GHGs to the atmosphere.[376] 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 GHGs that are less abundant than CO_2, but even better at retaining heat.[377]

6.6.2 Emissions from Oil and Gas Operations

GHG 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

[374] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

[375] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[376] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[377] http://www.dec.ny.gov/energy/44992.html.

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 compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[378]

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.[379]

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

[378] IPIECA and API, December 2003, p. 5-2.

[379] http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.

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.[380]

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 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.[381] 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.[382]

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 API, the Gas Research Institute (GRI) and the EPA – has been directed towards developing relatively robust emissions estimates at the national level.[383] 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, 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.[384] The report, which includes a

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[380] API 2004; amended 2005. p 4-1.
[381] ICF Task 2, 2009, p. 21.
[382] IPIECA and API, December 2003., p. 5-6.
[383] New Mexico Climate Change Advisory Group, November 2006, , pp. D-35.
[384] ICF Task 2, 2009.

discussion on GHGs, 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); and
- Well Production.

Transport of materials and equipment is an 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. The estimated required truck trips per well and corresponding fuel usage for the below noted phases requiring transportation, except well production, were provided by industry.[385]

Drilling Rig Mobilization, Site Preparation and Demobilization

Drill Pad and Road Construction Equipment
Drilling Rig
Drilling Fluid and Materials
Drilling Equipment (casing, drill pipe, etc.)

Completion Rig Mobilization and Demobilization

Completion Rig

[385] ALL Consulting, 2011, Exhibits 19B, 20B.

Well Completion

Completion Fluid and Materials
Completion Equipment (pipe, wellhead)
Hydraulic Fracturing Equipment (pump trucks, tanks)
Hydraulic Fracturing Water
Hydraulic Fracturing Sand
Flow Back Water Removal

Well Production[386]

Production Equipment (5 – 10 Truckloads)

Mileage estimates for both light duty and heavy duty trucks were used to determine total fuel usage 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.

Three distinct types of well projects were evaluated for GHG emissions as follows:

- Single-Well Vertical Project;
- Single-Well Horizontal Project; and
- Four -Well Pad (i.e., four horizontal wells at the same site).

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 four) would be drilled, followed by the completion of all wells (i.e., one or four) and subsequent production of all wells (i.e., one or four). A number of operators have indicated to the Department that activities on multi-well pads would 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. Nevertheless, four wells was the number of wells selected for

386 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.

the multi-well pad GHG analysis because industry indicated that number would be the maximum number of wells drilled at the same site in any 12 consecutive months.

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 6.25 and Table 6.26 below, 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.[387] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.25 - Assumed Drilling & Completion Time Frames for Single Vertical Well (New July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	13 / 312	6½ / 156
Completion	¼ / 6 (hydraulic fracturing) 1 / 24 (rig)	¼ / 6 (hydraulic fracturing) ½ / 12 (rig)
Flaring	3 / 72	3 / 72

Table 6.26 - Assumed Drilling & Completion Time Frames for Single Horizontal Well (Updated July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	25 / 600	12½ / 300
Completion	2 / 48 (hydraulic fracturing) 2 / 48 (rig)	2 / 48 (hydraulic fracturing) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

387 ALL Consulting, 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 or are based on gas throughput. 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.

$$\text{Emissions (tons/yr.)} = \text{Emissions Factor (lbs./hr)} \times \text{Duration (yr.)} \times (8{,}760 \text{ hrs/yr.}) \times (1 \text{ US short ton}/2{,}000 \text{ lbs}) \times \text{Activity Factor}$$

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.[388] 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, where fuel use data was not available VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile

[388] API, 2004; amended 2005., p. 4-3.

sources. A sample calculation showing this 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 CO_2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of 10 MMcf/d. 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. Light-duty and heavy-duty vehicles use is accounted for and differentiated in this analysis.[389] 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 EPA 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.[390]

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

[389] ALL Consulting, 2011, Exhibits 19B, 20B.

[390] API, 2004; amended 2005, pp. 4-32, 4-33.

estimated fuel usage, or use a fuel usage estimate if available. These methodologies were used to calculate the tons of CO_2 emissions from 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 for transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. For horizontal wells, 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 four-well pad. As shown in the table, approximately 15 tons of CO_2 emissions are expected from a mobilization of the drilling rig, including site preparation. Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered. 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. As shown in the table, approximately 4 tons of CO_2 emissions may be generated from a mobilization of the completion rig. For simplification, transportation associated with rig mobilization for the completion rig was assumed to be the same as that for the drilling rig. It is acknowledged that this assumption is conservative.

6.6.7 Well Drilling

Vertical wells may be drilled entirely using compressed air as the drilling fluid or possibly with air for a portion of the well and mud in the target interval. For horizontal wells, drilling activities would typically include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Regardless of the type of well, 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 83 tons of CO_2 emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show CO_2 emissions of 194 tons and 776 tons for the drilling of a single horizontal well and four-well pad, respectively.

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 fracturing 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-7, GHG-8 and GHG-9 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 single vertical well, single horizontal well and a four-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. The results of this evaluation are shown in Tables GHG-7, GHG-8 and GHG-9 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on estimated fuel usage for both light and heavy trucks. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-7, transportation related completion-phase emissions of CO_2 for a single vertical well is estimated at 12 tons. For the single horizontal well and the four-well pad (see Table GHG-8 and GHG-9), transportation related completion-phase CO_2 emissions are estimated at 31 to 115 tons, respectively.

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. Fuel usage for the single vertical well was prorated to account for less time pumping (i.e., one-eighth). Tables GHG-7, GHG-8 and GHG-9 show that approximately 54 tons and 325 tons of CO_2 emissions per well would be generated as a result of single vertical well and single horizontal well hydraulic fracturing operations, respectively.

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.[391] However, only controlled combustion events would be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. If a sales line is available, 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.[392] Otherwise, the gas is flared and combusted at the flare stack. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, approximately 1,728 tons of CO_2 and 12 tons of CH_4 emissions are generated per well during a three-day flaring operation for a 10 Mmcf/d 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.[393] The duration of flaring operations may be 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 REC and is

[391] API, 2004; amended 2005. p. 4-27.

[392] ALL Consulting, 2009. p. 14.

[393] ICF Task 2, 2009, p. 28.

further discussed in Chapter 7 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 4 tons per single vertical well and 7 tons per single horizontal well. No stage plug milling is normally required and less tubing is run for a single vertical well as compared to a horizontal well, and less completion time results in less GHG emissions. After the completion rig is removed from the site, earth moving equipment would be transported to the site and the area would be reworked and graded, which adds another 9 tons of CO_2 emissions for either a one-well project or four-well pad. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a single vertical well, single horizontal well and a four-well pad, respectively. Site work for a single vertical well would be less due to a smaller pad size but for simplification, site work is assumed the same for all well scenarios considered.

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. As previously stated, GHG emissions of CO_2 from transportation rely on estimated fuel usage where available or VMT, which ultimately requires a determination of fuel usage. Such emissions associated with well production activities, include those from transportation related to the removal of production 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-10, GHG-11 and GHG-12 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite for a one-well project and a four-well pad results in first-year CO_2emissions of approximately 3 tons and 11 tons, respectively.

Well production may require the removal of production 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. Transportation estimates were used to determine CO_2 emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 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 vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents CO_2 and CH_4 emissions for a four-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 229 days (i.e., 365 days minus 136 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-14 shows estimated annual emissions for a four-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.[394] The emission rates

[394] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

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 single vertical well, single horizontal well and four-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-10, GHG-11, GHG-12, GHG-13 and GHG-14 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 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 single vertical well, single horizontal well and four-well pad are detailed in Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year thereafter for each project type.

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.[395] 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.[396] 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 6.27 were used to determine total GHGs as CO_2e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 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.

Table 6.27 - Global Warming Potential for Given Time Horizon[397]

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 6.28 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., single vertical well, single horizontal well and four-well pad), sourcing of equipment and materials.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual GHG emissions. 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.

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395 API, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

396 Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

397 Adapted from Forster, et al. 2007, Table 2.14. Chapter 2, p. 212. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Table 6.28 - Summary of Estimated Greenhouse Gas Emissions (Revised July 2011)

	CO_2 (tons)	CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[398]	Total Emissions from Proposed Activity CO_2e (tons)
Estimated First-Year Green House Gas Emissions from Single Vertical Well	8,660	246	6,150	14,810
Estimated First-Year Green House Gas Emissions from Single Horizontal Well	8,761	240	6,000	14,761
Estimated First-Year Green House Gas Emissions from Four-Well Pad	13,901	402	10,050	23,951
Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical or Single Horizontal Well	6,164	244	6,100	12,264
Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Project	6,183	565	14,125	20,300

[398] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Some 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 6.29, 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 would 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.[399]

- Incomplete, unclear or faulty definitions of emission sources;
- Natural variability of the process that produces the emissions; and
- 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 6.28 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 Chapter 7, is a discussion of possible mitigation measures geared toward reducing GHGs that would be required, with emphasis on CH_4.

[399] API, August 2009, p. 3-30. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

Table 6.29 - Emission Estimation Approaches – General Considerations[400]

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.	

[400] API August 2009, p. 3-9, http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

6.7 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 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 and sludge.) Based upon currently available information it is anticipated that flowback water will not contain levels of NORM of significance, whereas production brine is known to contain elevated NORM levels. Radium-226 is the primary radionuclide of concern from the Marcellus.

Elevated levels of NORM in production brine (measured in picocuries/liter or pCi/L) may result in the buildup of pipe scale containing elevated levels of radium (measured in pCi/g). The amount and concentration of radium in the pipe scale would depend on many conditions, including pressures and temperatures of operation, amount of available radium in the formation, chemical properties, etc. Because the concentration of radium in the pipe scale cannot be measured without removing or disconnecting the pipe, a surrogate method is employed, conducting a radiation survey of the pipe exterior. A high concentration of radium in the scale would result in an elevated radiation exposure level at the pipe's exterior surface (measured in mR/hr) and can be detected with a commonly used survey instrument. The Department of Health would require a radioactive materials license when the radiation exposure levels of accessible piping and equipment are greater than 50 microR/hr (μR/hr). Equipment that exhibits dose rates in excess of this level will be considered to contain processed and concentrated NORM for the purpose of waste determinations.

Oil and gas NORM occurs in both liquid (production brine), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the highest concentrations of NORM are in production brine, 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 (pipe scale and sludge) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also wastes from the treatment of production brines may contain concentrated

NORM and therefore may require controls to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with 6 NYCRR § 380.4.

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 (Table 6.30). Radon gas, which under most circumstances is 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.

Table 6.30 - 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 production brine (>109 billion 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.

In NYS the disposal of processed and concentrated NORM in the form of pipe scale or water treatment waste is subject to regulation under Part 380. Because disposal of Part 380 regulated waste is prohibited in Part 360 regulated solid waste landfills, this waste would require disposal in out-of-state facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select RCRA C facilities and low-level radioactive waste disposal sites.

6.8 Socioeconomic Impacts[401]

This section provides a discussion of the potential socioeconomic impacts on the Economy, Employment, and Income (Section 6.8.1); Population (Section 6.8.2); Housing (Section 6.8.3); Government Revenues and Expenditures (Section 6.8.4); and Environmental Justice (Section 6.8.5). A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS.

To estimate the socioeconomic impacts associated with the use of high-volume hydraulic fracturing techniques for extracting natural gas, several assumptions must be made about the amount of natural gas development that would occur, the expected rate of development, the length of time over which that development would occur, and the distribution of this development throughout the state.

For the purposes of this SGEIS, the expected rate of development is measured by the number of wells constructed annually. Two different levels of development are analyzed – a low development scenario, and an average development scenario. These development scenarios were developed by the Department based on information the Department had requested from the Independent Oil & Gas Association of New York (IOGA-NY). IOGA-NY started with an estimated average rate of development based on the following assumptions:

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401 Section 6.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Approximately 67% of the area covered by the Marcellus and Utica shale is developable;

- Approximately 90% of wells would be horizontal wells, with an average of 160 acres/well; and

- Approximately 10% of wells would be vertical wells, with an average of 40 acres/well.

For the low rate of development, DEC assumed a rate of 25% of IOGA-NY's estimated average rate of development.

Table 6.31 provides a highlight of the major assumptions for each of these scenarios. In both scenarios, the maximum build-out of new wells is assumed to be completed in Year 30. Under the low development scenario, a total of 9,461 horizontal wells and 1,071 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). Under the average development scenario a total of 37,842 horizontal wells and 4,284 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). The high development scenario, which is analyzed in the Economic Assessment Report, assumes a total of 56,508 horizontal and 6,273 vertical wells are constructed at maximum build-out (e.g., Year 30).

Analysis of the high development scenario is not included in this socioeconomic section of the SGEIS in order to be conservative in assessing the positive potential economic benefits of high-volume hydraulic fracturing in New York State. The high development scenario was used as the conservative assumption of activity for all other sections of this SGEIS.

Economic realities, including diminishing marginal returns associated with drilling wells further from the fairway in less than ideal locations, and the exclusion of high-volume hydraulic fracturing wells from certain sensitive locations, would make it highly unlikely that the maximum build-out under the high development scenario would occur. Therefore, only the low and average development scenarios are discussed throughout this section.

These development scenarios are designed to provide order-of-magnitude estimates for the following socioeconomic analysis and are in no way meant to forecast actual well development levels in the Marcellus and Utica Shale reserves in New York State. These scenarios should be viewed as a “best estimate” of the range of possible amounts of development that could occur in New York State.

Table 6.31 - Major Development Scenario Assumptions (New August 2011)

	Scenarios	
	Low	**Average**
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	9,461	37,842
Vertical	1,071	4,284
Total	**10,532**	**42,126**
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	371	1,484
Vertical	42	168
Total	**413**	**1,652**

Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year “ramp-up” period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end. This assumption, which does not significantly affect the socioeconomic impact analysis, was used to remain consistent with other sections of the SGEIS. In actuality, well development would more likely gradually ramp up, reach a peak, and then gradually ramp down as fewer and fewer wells were completed. However, this curve would not necessarily be smooth.

It is unlikely that new well construction would occur under a steady, constant rate. Economic factors such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of the state and nation would all affect the yearly rate of well construction and the overall level of development of the gas reserves. The actual track of well construction would likely be much more cyclical in nature than as described in the following sections.

The average development scenario should be viewed as the upper boundary of possible development, while the low development scenario should be viewed as the likely lower boundary of possible development. As shown in Table 6.31, the maximum number of new wells developed in a year under the low development scenario is 371 horizontal and 42 vertical wells, and the maximum number of new wells developed in a year under the average development scenario is 1,484 horizontal and 168 vertical wells.

Each newly constructed well is assumed to have an average productive life of 30 years. For example, wells constructed in Year 1 are assumed to still be producing in Year 30, and wells constructed in Year 10 are assumed to produce until Year 40. Because of the assumption of a 30-year development period, wells constructed in Year 30 are assumed to be productive until Year 60. Assuming a 30-year development period and a 30-year production life for each well, the number of productive wells in New York State would be expected to grow until Year 30, at which point, the number of productive wells would peak. After Year 30, with no new wells being constructed, the number of wells in production would begin to decline. Because the number of annual wells approved and developed each year is different for the two development scenarios, the peak number of operating wells at Year 30 also differs for each scenario.

Under both development scenarios, natural gas production in New York State would occur from Year 1 until Year 60, with Year 30 having the maximum number of wells in production. After Year 30, producing wells would gradually decline until Year 60, at which time it is assumed that production stops.

As discussed in Section 1, no site-specific project locations are being evaluated in the SGEIS. Therefore, for purposes of analysis, three distinct regions were identified within the area where potential drilling may occur in order to take a closer look at the potential impacts at the regional and local levels. The three regions were selected to evaluate differences between areas with a high, moderate, and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

- Region A: Broome County, Chemung County, and Tioga County;
- Region B: Delaware County, Otsego County; and Sullivan County; and
- Region C: Cattaraugus County and Chautauqua County

This analysis is not intended to imply that impacts would occur only in these three regions. Impacts would occur at the local and regional levels wherever high-volume hydraulic fracturing wells are constructed. The actual locations of these wells have not yet been determined, and they could be constructed wherever there is low-permeable shale. Similar to the development scenarios described above, the representative regions are designed to give a range of possible socioeconomic impacts. Therefore, the results of the local and regional analysis should also be seen as order-of-magnitude estimates for the range of possible impacts. Further descriptions of the regions are provided in Section 2.3.11.

6.8.1 Economy, Employment, and Income

The following discusses the potential impacts on the economy, employment and income for New York State, and the local areas within each of the three regions (Regions A, B and C).

6.8.1.1 New York State

Economy and Employment

Development of low-permeability natural gas reservoirs in the Marcellus and Utica shale by high-volume hydraulic fracturing would be expected to have a significant, positive impact on the economy of New York State. Construction and operation of the new natural gas wells are expected to increase employment, earnings, and economic output throughout the state. According to statistics collected and calculations made by the Marcellus Shale Education and Training Center (the Center), in Pennsylvania, an average natural gas well using the high-volume hydraulic fracturing technique requires 410 individuals working in 150 different occupations. The manpower requirements to drill a single well were calculated to be 11.53 full-time equivalent (FTE) construction workers (Marcellus Shale Education and Training Center 2009).

A full-time equivalent worker is defined as one worker working eight hours a day for 260 days a year, or several workers working a total of 2,080 hours in a year. While the Center found that up to 410 individuals are required to build one well, only 11.53 FTE workers were needed. Typically, a high-volume hydraulic fracturing well is constructed over a 3- to 4-month period, and many of the individuals and occupations are needed for only a very short duration. Therefore, to accurately assess the economic impacts of constructing a high-volume hydraulic fracturing well, the FTE workforce was considered.

The Center also calculated the work force requirements for operating a well as 0.17 FTE workers, or approximately 354 person hours per year. In other words, approximately 1 FTE worker is required to operate and maintain every 6 wells in production (Marcellus Shale Employment and Training Center 2009). Unlike the construction workforce that drills the well within a few months and is finished, the operational workforce is required for the productive life of the well. For the purposes of this analysis, a 30-year productive life has been assumed for each well drilled. Therefore, for every new well drilled, 0.17 FTE workers are employed for 30 years.

In its study, the Marcellus Shale Employment and Training Center did not differentiate between the labor requirements needed to drill a horizontal versus a vertical well. Typically, it is much more costly and labor-intensive to drill a high-volume hydraulic fracturing horizontal well than it is to drill a high-volume hydraulic fracturing vertical well. Therefore, in an effort to be conservative and not overstate the positive economic impacts, a factor was applied to the 11.53 FTE figure for vertical wells in the estimates used for this analysis. This factor was calculated using the average depth of a vertical well compared to the average depth of a high-volume hydraulic-fracturing horizontal well. The resulting ratio of 0.2777 was applied to the 11.53 FTE labor requirement to estimate the overall labor requirements of a vertical well.

Using the workforce requirement figures developed by the Marcellus Shale Employment and Training Center and the two development scenarios described above, the expected impacts on employment and earnings from high-volume hydraulic fracturing were projected for New York State as a whole.

As shown in Table 6.32, annual direct construction employment is directly related to the number of wells drilled in a given year. At the maximum well construction rate assumed for each development scenario, total annual direct construction employment is predicted to range from 4,408 FTE workers under the low development scenario to 17,634 FTE workers under the average development scenario. These employment figures correspond to the annual construction of 413 horizontal and vertical wells under the low development scenario and 1,652 horizontal and vertical wells under the average development scenario. In order to reach the full build-out potential used in the scenarios, it is assumed that construction employment and new well construction would remain at these levels for 20 years, starting in Year 10 (see Table 6.32).

The maximum direct production employment under each development scenario is also shown in Table 6.32. These figures represent the peak production year (Year 30), when the maximum build-out potential has been reached before any of the wells have stopped producing. The preceding and the following years all would have fewer production workers. At the peak, production employment would be expected to range from 1,790 FTE workers under the low development scenario to 7,161 FTE workers under the average development scenario (Table 6.32).

Table 6.32 - Maximum Direct and Indirect Employment Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Direct Employment Impacts		
Construction Employment[1]	4,408	17,634
Production Employment[2]	1,790	7,161
Indirect Employment [3]	7,293	29,174
Total Employment Impacts	13,491	53,969
Total Employment as a Percent of New York State 2010 Labor Force	0.2%	0.7%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

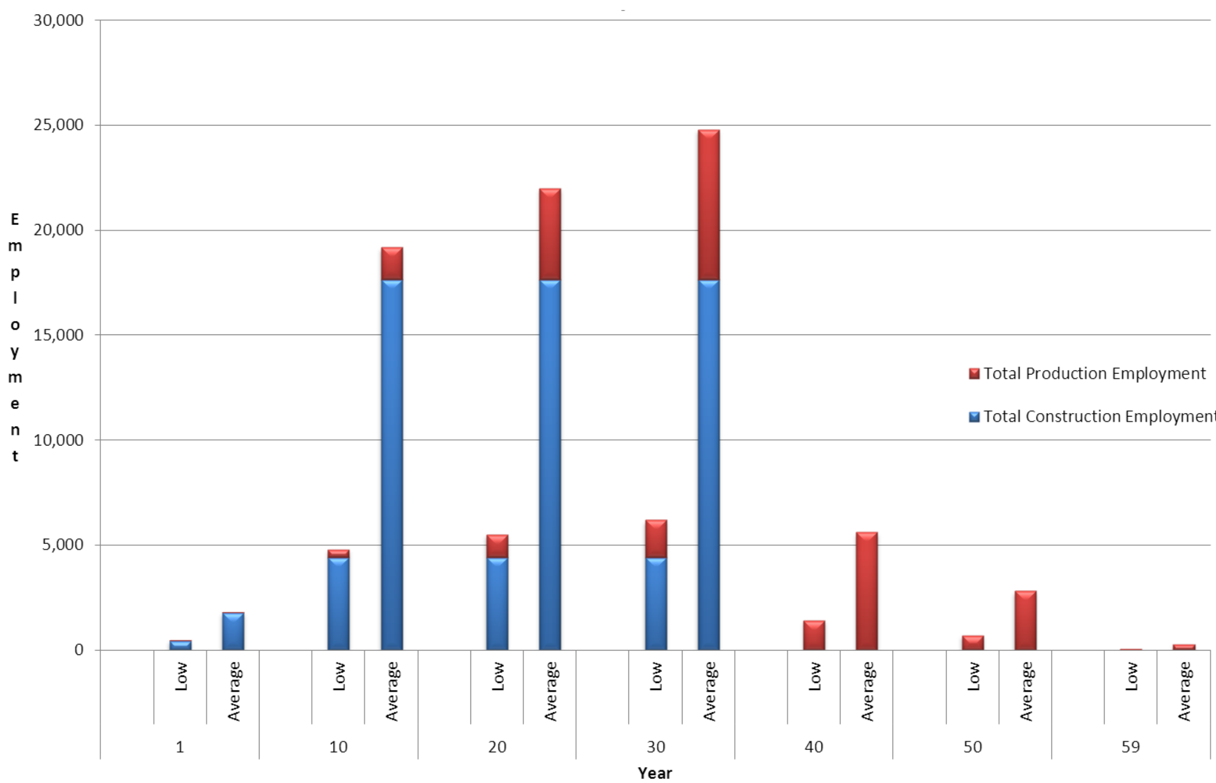
1 These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

2 These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production employment for all other years.

3 Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

Figure 6.13 illustrates the projected direct employment in New York State that would result from implementation of each development scenario over the 60-year time frame. The figure shows how construction and production employment levels are expected to vary, with peak direct employment occurring in Year 30.

Figure 6.13 – Projected Direct Employment in New York State Resulting
from Each Development Scenario (New August 2011)

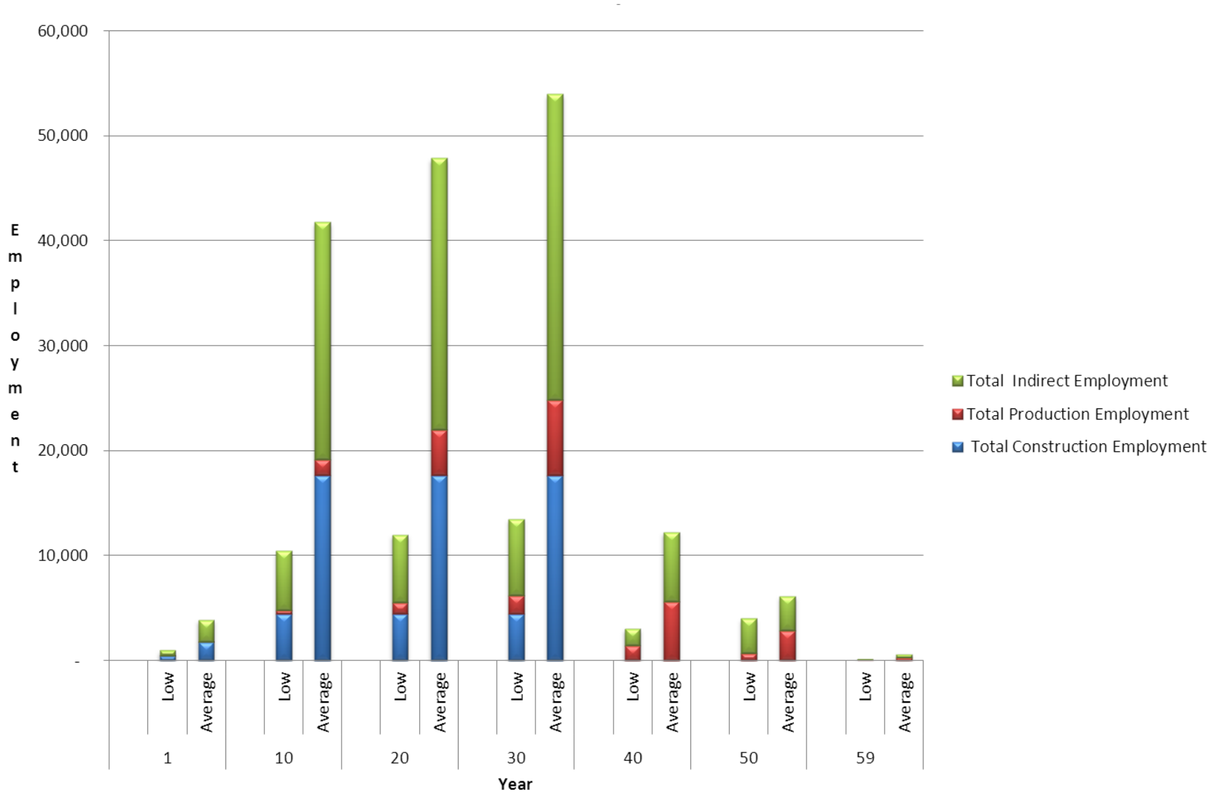


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from suppliers in New York State, the overall demand for goods and services in the state would expand. Revenues at the wholesale and retail outlets and service providers within the state would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the state, thus "multiplying" the positive economic impacts of the original increase in construction/production spending. These "multiplier" effects would continue on until all of the original funds have left New York State's economy through either taxes or savings, or through purchases from outside the state.

Indirect employment impacts are expected to range from an additional 7,293 FTE workers under the low development scenario to an additional 29,174 FTE workers under the average development scenario. These annual figures represent the year with the maximum employment (Year 30). The years before and after this date would have less direct and indirect employment.

In total, at peak employment years, state approval of drilling in the Marcellus and Utica Shales is expected to generate between 13,491 and 53,969 direct and indirect jobs, which equates to 0.2% and 0.6%, respectively, of New York State's 2010 total labor force, depending on the level and intensity of development that occurs (see Table 6.32). Figure 6.14 graphically illustrates the projected total employment in New York State that would result from each development scenario. As shown on the figure, total employment levels would be highest in Year 10 through Year 30. Once new well construction ends in Year 31, the direct and indirect employment would be greatly reduced.

Figure 6.14 - Projected Total Employment in New York State Resulting from Each Development Scenario (New August 2011)



The majority of these indirect jobs would be concentrated in the construction, professional, scientific, and technical services; real estate and rental/leasing; administrative and waste management services; management of companies and enterprises; and manufacturing industries.

Income

The increase in direct and indirect employment would have a positive impact on income levels in New York State. Table 6.33 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 through Year 30), total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30, the year that the maximum number of operational workers are assumed to be employed.

Table 6.33 - Maximum Direct and Indirect Annual Employee Earnings Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Direct Earnings Impacts		
Construction Earnings[1]	$298.4	$1,193.8
Production Earnings[2]	$121.2	$484.8
Indirect Employee Earnings Impacts[2,3]	$202.3	$809.2
Total Employee Earnings Impacts	$621.9	$2,487.8
Total Employee Earnings as a Percent of New York State's 2009 Total Wages	0.1%	0.5%

Source: U.S. Bureau of Economic Analysis 2011a; NYDOL 2009.

1 These figures represent the maximum annual change in construction earnings under each scenario and correspond to construction earnings in Years 10 - 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

2 These figures represent the maximum annual production earnings and indirect employee earnings under each development scenario. These figures correspond to operations earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation earnings for all other years.

3 Type I direct earnings multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

As described above, the construction and production activities would also generate significant indirect economic impacts. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. These figures equate to increases of between 0.1% and 0.5% of the total wages and salaries earned in New York State during 2009 (see Table 6.33).

Owners of the subsurface mineral rights where wells are drilled will also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or more of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, can result in significant increases in income. Signing bonuses/bonus bids also can provide significant additional income to property owners.

6.8.1.2 Representative Regions

As noted above, three representative regions were selected to show the range of possible socioeconomic impacts that could occur at the local and regional levels. This analysis in no way is meant to imply that impacts will occur only in these three regions.

For purposes of this analysis, it is assumed that 50% of all new well construction would occur in Region A (Chemung, Tioga, and Broome counties); 23% would occur in Region B (Otsego, Delaware, and Sullivan counties); 5% would occur in Region C (Chautauqua and Cattaraugus counties); and the remaining 22% of new well construction would occur in the rest of New York State. Geological data on the extent and thickness of the low-permeability shale in New York State, including the Marcellus Shale and Utica Shale fairways, were the basis for these assumptions.

Table 6.34 details the major assumptions for each development scenario for each representative region. In all cases, total development is assumed to be reached at Year 30. As shown in the table, Region A is anticipated to receive the majority of the new well construction. The analysis of Region A is designed to show the upper bound of potential regional economic impacts. Under the low development scenario, a total of 5,281 new wells would be constructed in the counties of Tioga, Chemung, and Broome. Under the average development scenario, a total of 21,067 new wells would be constructed in Region A. The projected maximum number of new wells developed per year in Region A would range from 207 to 826 wells, depending on the development scenario considered. The projected maximum number of new wells developed per year in Region B would range from 2,425 to 9,690 wells, depending on the development scenario (see Table 6.34).

In contrast, Region C is assumed to experience a much smaller level of well development than Region A or Region B. The analysis of Region C is designed to show the lower bound of potential regional economic impacts. Under the low development scenario, a total of 534 new wells would be constructed in Region C. Under the average development scenario, a total of 2,095 new wells would be constructed in Region C. The maximum number of new wells constructed each year in Region C is assumed to be 21 wells under the low development scenario and 82 wells under the average development scenario. The remaining 22% of the development would occur in the rest of the state (see Table 6.34).

Table 6.34 - Major Development Scenario Assumptions for Each Representative Region (New August 2011)

	Scenarios	
	Low	**Average**
Region A		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	4,743	18,923
Vertical	538	2,144
Total	5,281	21,067
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	186	742
Vertical	21	84
Total	207	826
Region B		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,170	8,697
Vertical	255	993
Total	2,425	9,690
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	85	341
Vertical	10	39

	Scenarios	
	Low	**Average**
Total	95	380
Region C		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	483	1,888
Vertical	51	207
Total	534	2,095
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	19	74
Vertical	2	8
Total	21	82
Rest of State		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,065	8,334
Vertical	227	940
Total	2,292	9,274
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	81	327
Vertical	9	37
Total	90	364

Economy and Employment

The proposed approval of the use of high-volume hydraulic fracturing technique would have a significant positive economic impact at the regional and local levels. Using the same methodology described above for the statewide analysis, the FTE labor requirements needed to construct and operate these wells were estimated for each region. Table 6.35 provides the maximum direct and indirect employment impacts that are predicted to occur under each development scenario for each region.

In Region A, which is used to define an upper boundary of the regional socioeconomic impacts, it is projected that direct construction employment would range from 2,204 FTE construction workers at the maximum employment levels under the low development scenario to 8,818 FTE construction workers at the maximum employment levels under the average development scenario. The new production employment in the region is expected to range from 895 to 3,581 FTE production workers per year.

In contrast, employment impacts are not anticipated to be as large in Region C, which is used to define a lower boundary for the regional socioeconomic impacts. At the maximum employment levels under the low development scenario, an estimated 221 new FTE constructions workers and 90 new FTE production workers would be needed for drilling and maintaining the new natural gas wells. These figures would increase to 882 new FTE construction workers and 358 new FTE production workers under the average development scenario (see Table 6.35).

Table 6.35 - Maximum Direct and Indirect Employment Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Employment[1]	2,204	8,818
Production Employment[2]	895	3,581
Indirect Employment Impacts[3]	650	2,600
Total Employment Impacts	3,749	14,999
Total Employment as a Percentage of Region A's 2010 Total Labor Force	2.3%	9.3%
Region B		
Direct Employment Impacts		
Construction Employment[1]	1,014	4,056
Production Employment[2]	412	1,647
Indirect Employment Impacts[3]	191	762
Total Employment Impacts	1,617	6,465
Total Employment as a Percentage of Region B's 2010 Total Labor Force	1.8%	7.3%
Region C		
Direct Employment Impacts		
Construction Employment[1]	221	882
Production Employment[2]	90	358
Indirect Employment Impacts[3]	66	263
Total Employment Impacts	377	1,503
Total Employment as a Percentage of Region C's 2010 Total Labor Force	0.4%	1.4%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

1 These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

2 These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation employment for all other years.

3 Separate Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II), were used for each region to estimate the indirect employment impacts.

Figure 6.15, Figure 6.16, and Figure 6.17 illustrate the projected direct employment in each representative region that would result from implementation of each development scenario over the 60-year time frame. The figures show how construction and production employment levels are expected to vary, with the peak direct employment occurring in Year 30.

Figure 6.15 - Projected Direct Employment in Region A Resulting from
Each Development Scenario (New August 2011)

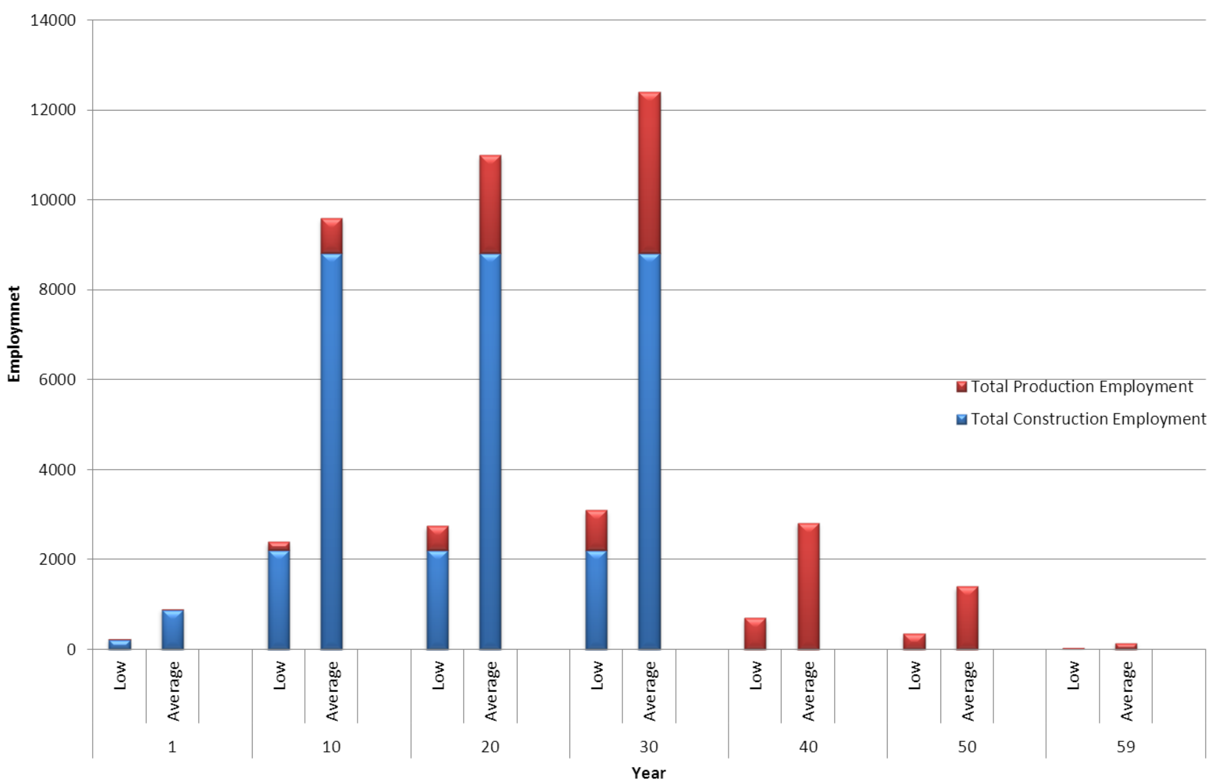


Figure 6.16 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

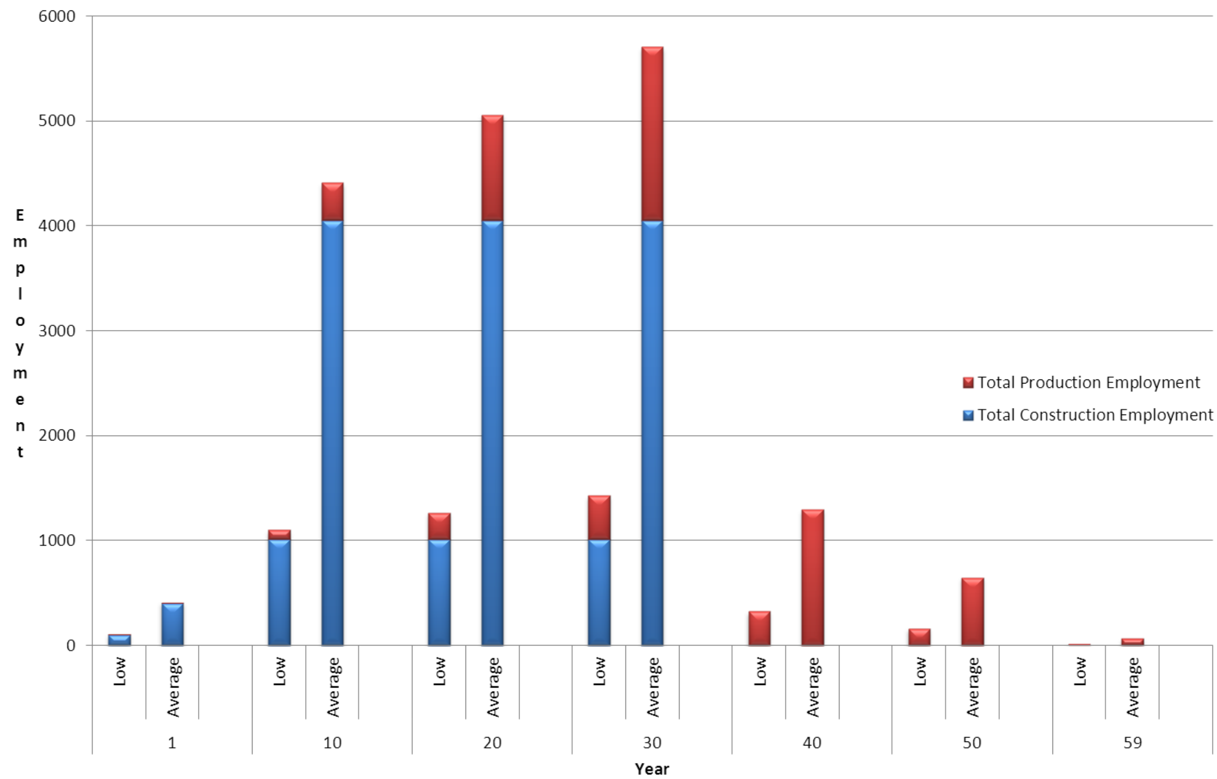
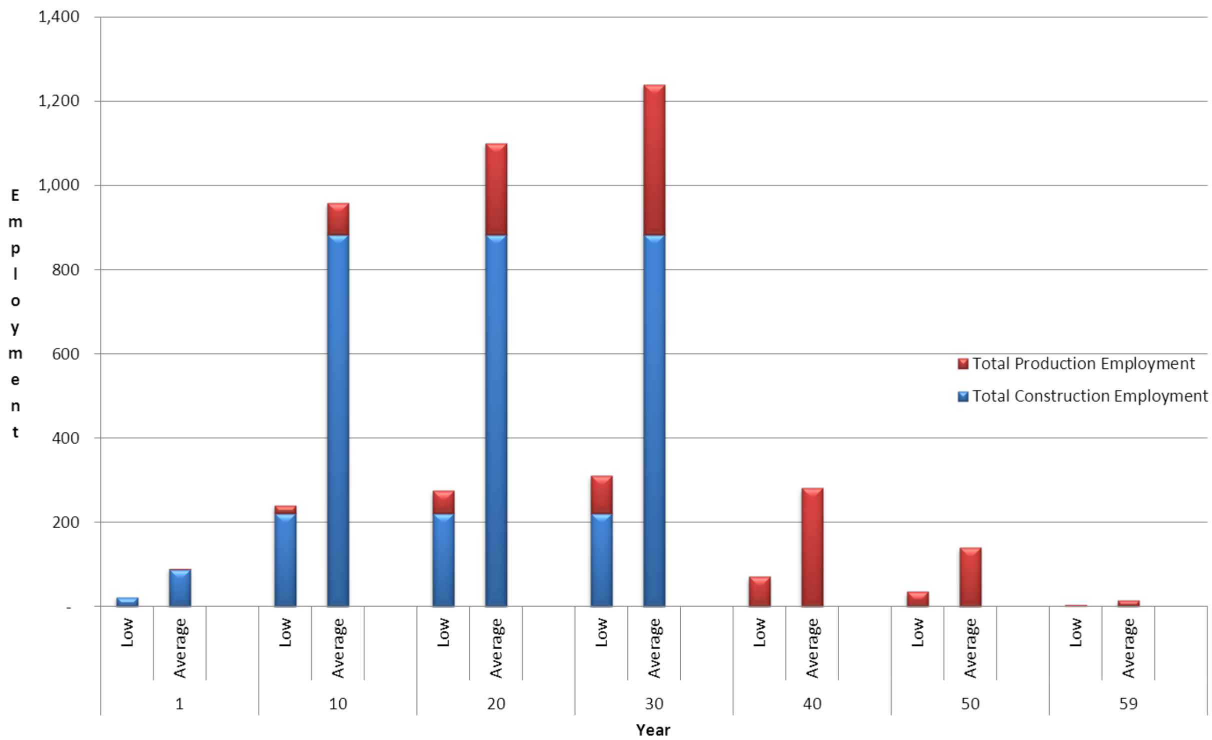


Figure 6.17 - Projected Direct Employment in Region C Resulting from Each Development Scenario (New August 2011)



As described previously for the statewide impacts, in addition to the direct employment impacts, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from regional suppliers, the overall demand for goods and services in the region would expand. Revenues at the region's wholesale and retail outlets and service providers would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the region, thus "multiplying" the positive economic impacts of the original increase in construction/operation spending. These "multiplier" effects would continue on until all of the original funds have left the region's economy through either taxes or savings, or through purchases from outside the region.

Indirect employment impacts are expected to range from a high of 650 to 2,600 indirect workers in Region A to a low of 66 to 263 indirect workers in Region C, depending on the development scenario. Direct employment multipliers of 1.4977 for Region A, 1.3272 for Region B, and 1.4657 for Region C for the oil and gas extraction industry were used in this analysis (U.S. Bureau of Economic Analysis 2011b; 2011c; 2011d). In contrast, New York State as a whole had a direct employment multiplier of 2.1766 for the oil and gas extraction industry (U.S. Bureau of Economic Analysis 2011a).

The employment and earnings multipliers in these regions are much smaller than in New York State as a whole, underscoring the fact that portions of these study areas do not have as well-developed, self-sufficient, and diverse economies as the state as a whole. In particular, the low multipliers reflect the fact that much of the goods and services that would be needed to construct and operate the new wells would be purchased outside the regions.

However, it can be expected that as the natural gas industry matures in these regions, more local suppliers and service providers would enter the markets and be able to respond to the natural gas industry's needs. As time goes by, a larger portion of the indirect economic impacts would remain in the region, further stimulating the local economies.

Figure 6.18, Figure 6.19, and Figure 6.20 graphically illustrate the projected total employment in Region A, Region B, and Region C, respectively, that would result from each development scenario. As shown on the figures, total employment levels would be greatest in Year 10 through Year 30. Once new well construction ends in Year 30, the projected direct and indirect employment would be greatly reduced.

Figure 6.18 – Projected Total Employment in Region A Under Each Development Scenario (New August 2011)

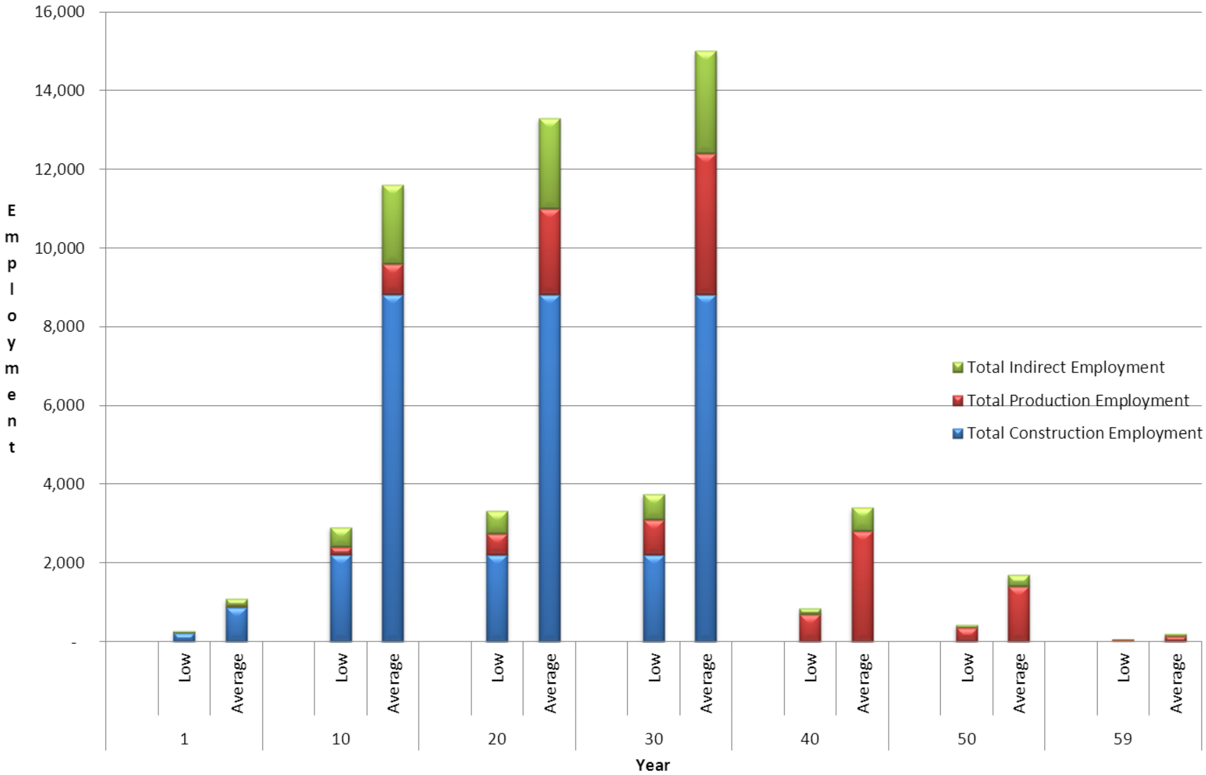


Figure 6.19 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

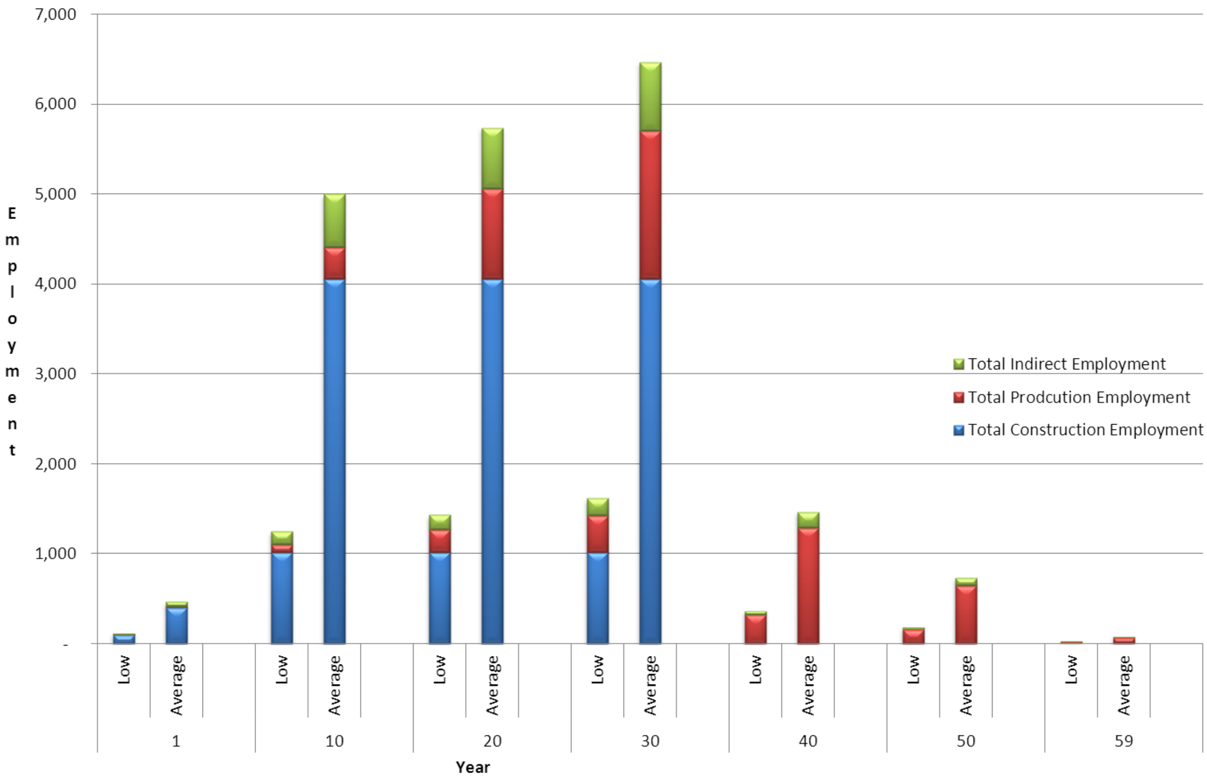
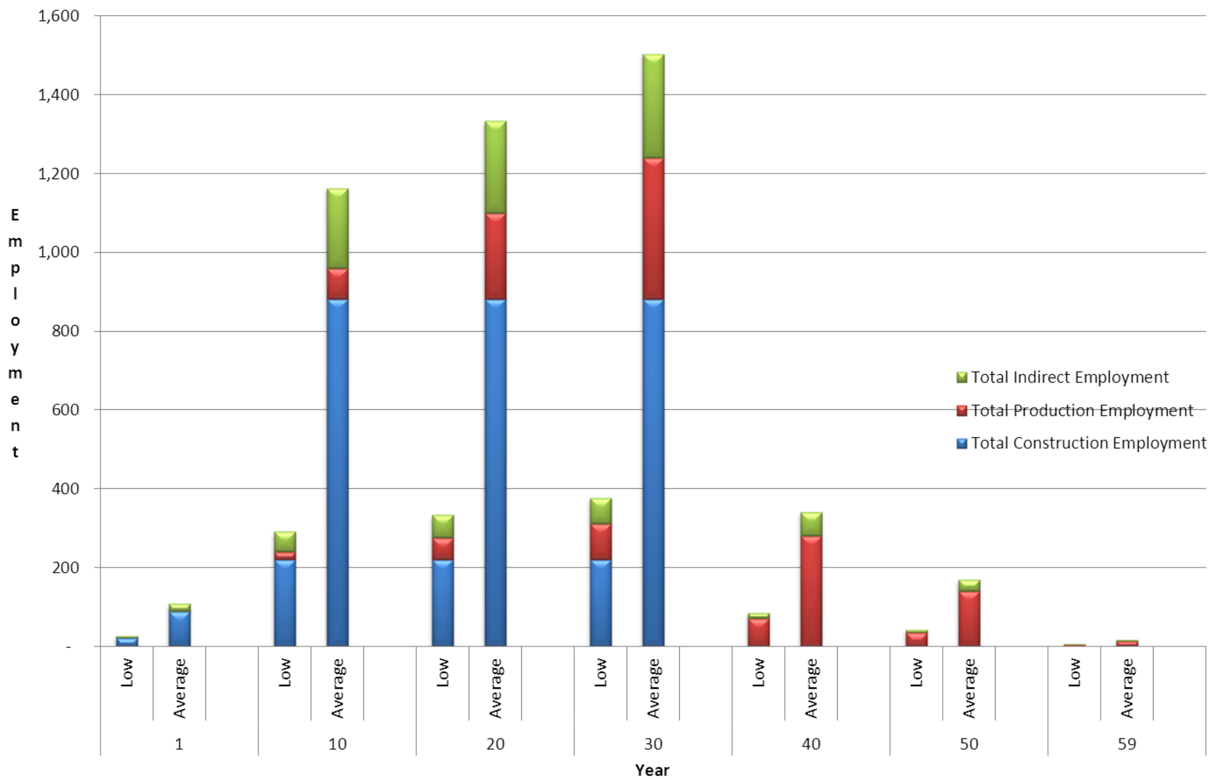


Figure 6.20 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeable shale is located. Many geological and economic factors would interact to determine the exact location that wells would be drilled. The location of productive wells would determine the distribution of impacts.

In some regions in the state where drilling is most likely to occur, the increases in employment may be so large that these regions may experience some short-term labor shortages. The increase in direct and indirect employment related to the natural gas extraction industry could drive wage rates up in the areas in the short term and make it more difficult for existing industries to recruit and retain qualified workers. In addition, the increase in wage rates could have a short-term, negative impact on existing industries as it would increase their labor costs. These potential short-term labor impacts would be less severe because specialized labor from outside the region would likely be required for certain jobs, and the existence of employment opportunities would cause the migration of workers into the region. In addition, the positive employment impacts from well construction and development—and the related economic impacts derived from that employment—would generate more in-migration to the region. In time, the additional new residents to the areas would expand the regional labor force and reduce the pressure on labor costs.

Income

The increase in direct and indirect employment would have a positive impact on income levels in regions where natural gas development occurs. Table 6.36 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 to Year 30), total annual construction earnings in a region could range from a low of $15.0 million in Region C under the low development scenario to nearly $597.0 million under the average development scenario in Region A. In Year 30, the year that the maximum number of production workers are assumed to be employed, regional employee earnings from production employment could range from a low of $6.1 million in Region C under the low development scenario to a high of $242.4 million in Region A under the average development scenario.

Table 6.36 - Maximum Direct and Indirect Earnings Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Earnings[1]	$149.2	$597.0
Production Earnings[2]	$60.6	
Indirect Earnings Impacts[3]	**$44.0**	**$176.0**
Total Earnings Impacts	**$253.8**	**$1,015.4**
Total Earnings as a Percentage of Region A's 2009 Total Wages	4.7%	18.7%
Region B		
Direct Earnings Impacts		
Construction Earnings[1]	$68.6	$274.6
Production Earnings[2]	$27.9	$111.5
Indirect Earnings Impacts[3]	**$12.9**	**$51.6**

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Total Earnings Impacts	**$109.4**	**$437.7**
Total Earnings as a Percentage of Region B's 2009 Total Wages	4.8%	19.3%
Region C		
Direct Earnings Impacts		
Construction Earnings[1]	$15.0	$59.7
Production Earnings[2]	$6.1	$24.2
Indirect Earnings Impacts[3]	$4.5	$17.8
Total Earnings Impacts	$25.6	$101.7
Total Earnings as a Percent of Region C's 2009 Total Wages	0.9%	3.7%

Source: U.S. Bureau of Economic Analysis 2011b, 2011c, 2011d; NYSDOL 2009.

1 These figures represent the maximum annual construction earnings under each scenario and correspond to construction earnings in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

2 These figures represent the maximum annual production earnings under each development scenario. These figures correspond to production employee earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production and indirect employee earnings for all other years.

3 Separate Type I direct earnings multipliers for the oil and gas extraction industry from the US Bureau of Economic Analysis, Regional Input- Output Modeling System (RIMS II) for each region were used to estimate the indirect employment impacts.

Total employee earnings in all of the regions are expected to increase significantly. Region A would experience annual increases in employee earnings of approximately $254 million to $1.0 billion, or 4.7% to 18.7% of the 2009 total wages and salaries for the region. Similarly, Region B would experience annual increases in employee earnings of approximately $109 million to $438 million, or 4.8% to 19.3% of 2009 total wages and salaries for the region. Region C would also experience a significant impact in its annual employee earnings. Employee earnings in this region would increase from approximately $26 million to $102 million, or 0.9% to 3.7% of the 2009 total wages and salaries for the region (see Table 6.36).

Owners of the subsurface mineral rights where wells are drilled would also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or greater of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, could result in significant increases in income. In addition, mineral rights owners often receive large signing bonuses/bonus bids as part of the lease agreements.

Impacts on Other Industries

The proposed high-volume hydraulic-fracturing operations would affect not only the size of the regional economies as described above, but would also have an impact on other industries in the economy.

As previously described, suppliers of the natural gas extraction industry would experience significant increases in demand for their goods and services. Over time, these industries would expand and their importance in the regional economies would likewise increase. As shown in Section 2.3.11, Economy, Employment, and Income, the industries expected to experience the greatest indirect, or secondary, growth due to expansion of the natural gas extraction industry would be real estate; the professional, scientific, and technical industries; the management of companies and enterprises; construction; and manufacturing industries. For every $1 million change in the final demand generated in the natural gas extraction industry, a corresponding significant level of output would be generated in these industries. Typically, a change in final demand in an industry is defined as the change in output of that industry multiplied by the value or price of its output. In this case, a $1 million increase in the value of output from the natural gas extraction industry would generate $47,100 in the real estate and rental and leasing industry; $30,500 in the professional, scientific, and technical services industry; and $27,600 in the management of companies and enterprises industry. See Section 2.3.15 for a discussion of indirect impacts on other industries in New York State.

Each of these secondary industries would experience increases in their output, employment, income and value added. As a result, industries that supply these secondary industries would also experience a positive economic impact, and they would expand as demand for their goods and services increases. Secondary, and eventually even tertiary, suppliers would start to tailor their products to meet the needs of the natural gas extraction industry.

Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.

Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry. Property values also may experience some increase as a result of the natural gas development and the resulting increase in economic activity. The potential increase in land prices, which is one of the main factors of production for agriculture, could impact the industry's input costs in areas experiencing the most intense development.

6.8.2 Population

This section presents a summary of the population and demographic findings of the Economic Assessment Report (2011) written by Ecology and Environment Engineering, P.C.

As described previously, three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels. The designation of these areas as representative regions does not mean that the impacts would necessarily be limited to those areas. Until the production potential of low-permeability reservoirs is proven, it is not possible to predict where every potential high-volume hydraulically fractured well may be sited; wells could be developed anywhere there is low-permeability shale. The local and regional impacts presented here are intended only to provide order-of-magnitude estimates for the range of potential impacts. See the Economic Assessment Report for a more detailed discussion on the selection of these representative regions.

To assess the maximum potential population impacts, the discussion below is based on a hypothetical situation in which all workers hired for the construction and production phases of the natural gas wells either migrate into the regions from other areas, or workers migrate into the regions from other areas to fill positions which local construction and production workers vacate to work on the natural gas wells. Although this hypothetical situation is used to examine the maximum potential population impacts, it is more likely that the actual outcome would be less than described. Not all workers employed during the construction and production phases would necessarily live in New York State or one of the representative regions. Particularly in the case of well development and production in the Southern Tier, existing natural gas workers currently residing in Pennsylvania, for example, may simply choose to maintain their residency in Pennsylvania and commute to work in New York.

In addition, actual population impacts may also be less than what is described in the following section because some currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

The hiring of currently employed local workers (i.e., those workers that leave existing jobs to work in the natural gas industry) is not expected to reduce total in-migration to the regions as it is assumed that the jobs these local workers are leaving would need to be filled. Given the finite number of workers in the regional labor force, any growth in the total number of jobs available in regional economies not filled by currently unemployed or underemployed persons would lead to in-migration to the areas.

The following additional assumptions were used to project population impacts:

- The majority of construction jobs and related population migration to the regions would be temporary and transient in nature in the beginning of the well development phase. As well construction continues, these jobs would gradually be filled by permanent residents.

- Transient construction workers are assumed to temporarily relocate to the region for a short-duration and are assumed to not be accompanied by their households. Permanent construction workers are assumed to relocate to the region for the duration of the well development phase and would be accompanied by their entire households.

- Production jobs and related population migration to the regions would be permanent and entire households would relocate to the regions.

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.

- Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

- The 2010 average household sizes in New York State (2.64 persons per household), Region A (2.47 persons per household), Region B (2.52 persons per household), and Region C (2.49 persons per household) were used in estimating the population impacts associated with permanent construction and production jobs (USCB 2010).

- There would be no involuntary displacement of persons due to construction of the natural gas wells, as no buildings would be demolished to make way for wells and wells need to be drilled at least 500 feet away from private wells and 100 feet from inhabited dwellings.

6.8.2.1 New York State

Both transient and permanent population impacts are expected to occur as a result of natural gas well construction. Given the highly specialized nature of natural gas construction, workers with the skills required to complete a high-volume hydraulic fracturing operation would not be currently available in New York State or in the representative regions. If high-volume hydraulic fracturing operations were to begin in New York State, most of the skilled workers would initially need to be recruited from outside the state and would be both temporary and transient in nature.

As the industry matures and as more natural gas development occurs in the state and representative regions, more local persons would acquire the requisite skills needed for these jobs, and recruitment from within the existing labor force would therefore increase. Also, as the industry expands and development becomes more assured, the incentive for previously transient workers to become permanent residents within the state or representative regions would increase. Therefore, it would be expected that eventually there would be a decline in the number of transient construction workers and an increase in the number of permanent construction workers.

In an effort to estimate the mix of transient and permanent construction workers, data collected by the Marcellus Shale Education and Training Center on the occupational composition of the natural gas workforce and data from the U.S. Bureau of Economic Analysis' 2008 National Employment Matrix were used to help forecast the amount of local labor that would be employed in natural gas well development (Marcellus Shale Education and Training Center 2009; U.S. Bureau of Economic Analysis 2011e). Initially no more than 23% of the construction workforce is expected to be hired locally. Due to New York State's small existing natural gas industry, the remaining 77% of the workforce would have specialized skills that would most likely be unavailable among New York's labor force in Year 1. Given the newness of the industry, it is assumed that, in Year 1, 77% of the total workforce would be transient workers from outside the state.

As the natural gas industry matures the number of qualified workers in the state and representative regions would increase. This pool of qualified workers would expand as existing local residents gain the requisite skills and/or formerly transient workers permanently relocate to the state or representative regions. The total number of transient construction workers would gradually increase as the rate of well development increased until Year 10 when the maximum number of transient construction workers under both development scenarios is reached. From Years 11 to 30 the transient population would gradually decrease as a proportion of the total construction workforce. By Year 30 it is assumed that the natural gas industry would be sufficiently mature that 90% of all workers could be hired locally. Table 6.37 shows the transient, permanent, and total construction employment for select years. See the Economic Assessment Report for a more detailed discussion of how these figures were derived.

Table 6.37 - Transient, Permanent and Total Construction Employment Under Each Development Scenario for Select Years: New York State (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	342	97	439	1,370	389	1,759
5	1,517	693	2,210	6,051	2,766	8,817
10	2,409	1,999	4,408	9,639	7,995	17,634
15	1,759	2,649	4,408	7,038	10,596	17,634
20	1,181	3,227	4,408	4,725	12,909	17,634
25	740	3,668	4,408	2,959	14,675	17,634
30	441	3,967	4,408	1,763	15,871	17,634

Since the natural gas wells are expected to stay in operation for 30 years, production workers are assumed to be permanent workers who reside close to where the wells are located. Thus, these workers would live in or relocate their families to the area. Wells drilled in Year 1 are expected to remain in operation until Year 30; wells drilled in Year 30 would remain in operation until Year 60.

It is assumed that the households of permanent construction workers and production workers would, on average, be the same size as existing New York households (i.e., 2.64 persons, including the single worker). Therefore, in projecting population impacts, it is anticipated that transient construction workers would be temporary residents unaccompanied by family members, whereas permanent construction workers and all production workers would be permanent residents accompanied by an average of 1.64 family members.

Based on the above assumptions, Table 6.38 displays, for New York State as a whole and for each development scenario, the estimated transient and permanent populations resulting from construction and production activities for Years 1, 10, 20, 30, 40, 50, and 59.

Table 6.38 - Estimated Population Associated with Construction and Production Employment for Select Years: New York State (New August 2011)

		Transient Population	**Permanent Population**		
Production Year	**Development Scenario**	**Construction**	**Construction**	**Production**	**Total**
1	Low	342	256	18	275
	Average	1,370	1,026	74	1,100
10	Low	2,409	5,277	1,019	6,296
	Average	9,639	21,107	4,079	25,186
20	Low	1,181	8,519	2,872	11,392
	Average	4,725	34,080	11,492	45,572
30	Low	441	10,473	4,726	15,198
	Average	1,763	41,898	18,905	60,803
40	Low	0	0	3,707	3,707
	Average	0	0	14,829	14,829
50	Low	0	0	1,853	1,853
	Average	0	0	7,413	7,413
59[1]	Low	0	0	185	185
	Average	0	0	742	742

Note:

[1] Year 59 is used instead of Year 60 since it is assumed that all operational wells would cease production at the beginning of Year 60.

Under the low development scenario, between Years 10 and 30, it is projected that a maximum of 4,408 construction workers would temporarily or permanently migrate into the areas. The maximum transient construction workforce would occur in Year 10, with an estimated 2,409 transient workers. (During this same year, there would be 1,999 permanent workers relocating to the area.) Under the average development scenario, between Years 10 and 30, it is projected that a maximum of 17,634 construction workers would temporarily or permanently migrate to the well construction areas. The maximum transient workforce would occur in Year 10, with an estimated 9,639 transient workers. (During this same time period, there would be 7,995 permanent workers relocating to the area.) The population impact of the maximum number of transient workers, 9,639 transient workers for the average development scenario, represents less than 0.1% of the total present population of New York State, indicating that transient workers would have only a minor short-term population impact at the state level.

Under the low development scenario, the number of persons permanently migrating to the impacted areas to construct and operate the wells is projected to reach its maximum of 15,198 persons during Year 30 (see Table 6.39). Under the average development scenario during Year 30, it is projected that 60,803 persons would permanently migrate to the impacted areas. Since it is assumed that permanent construction and production workers would relocate with their households, these population estimates include the permanent construction and production workers and members of their households. The maximum impact on the permanent population under the average development scenario is 60,803 persons in Year 30. This figure represents approximately 0.3% of the total present population of New York State, indicating that some long-term population impact could occur at the state level as a result of the operation of the new natural gas wells.

Table 6.39 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production: New York State (New August 2011)

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
New York State	19,378,102	Low	2,409	>0.1%	15,198	>0.1%
		Average	9,639	>0.1%	60,803	0.3%

Notes:

1 Existing population from U.S. Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum operational impacts occur during production year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

According to the population projections developed by Jan K. Vink of the Cornell University Program on Applied Demographics, the population of New York State is expected to increase by 1,037,344 persons over the next 20 years (i.e., by an average of approximately 52,000 persons per year) (Cornell University 2009). Consequently, the maximum cumulative population impact of 60,803 persons, which occurs during production year 30, is slightly more than one year's projected incremental population growth for New York State.

Although the maximum population impacts would be relatively minor at the level of the whole state, natural gas wells would not be spread evenly across the state; they would be concentrated in particular areas where the influx of construction workers and production workers and their families may have more significant population impacts. Similarly, because new wells would not be developed evenly over time due to swings in well development activity, the population impacts would be greater in some years than in others.

In addition to direct employment (employment impacts from construction and production), there are projected indirect employment impacts from the development of hydraulic fracturing operations in the area underlain by the Marcellus and Utica Shales (see Section 6.8.1.1). Given the relatively high unemployment rates currently being experienced in these regions, it is likely that some of these new, indirectly created jobs (e.g., gas station clerks, hotel lobby personnel, etc.) would be filled by local, previously unemployed or underemployed persons. These indirect employment impacts would reduce local unemployment and help stimulate the local economies. The impacts associated with the influx of construction workers, both transient and permanent, would last as long as wells are being developed in an area, whereas the impacts associated with the production phase could last up to 60 years.

6.8.2.2 Representative Regions

Table 6.40, Table 6.41, and Table 6.42 show the estimated transient, permanent, and total construction employment for Regions A, B, and C under the low and average development scenario.

Table 6.40 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region A (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	171	48	219	686	194	880
5	758	347	1,105	3,026	1,383	4,409
10	1,205	999	2,204	4,820	3,998	8,818
15	880	1,324	2,204	3,520	5,298	8,818
20	591	1,613	2,204	2,363	6,455	8,818
25	370	1,834	2,204	1,480	7,338	8,818
30	220	1,984	2,204	882	7,936	8,818

Table 6.41 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region B (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	79	22	101	315	89	404
5	349	159	508	1,392	636	2,028
10	554	460	1,014	2,217	1,839	4,056
15	405	609	1,014	1,619	2,437	4,056
20	272	742	1,014	1,087	2,969	4,056
25	170	844	1,014	681	3,375	4,056
30	101	913	1,014	406	3,650	4,056

Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	17	5	22	69	19	88
5	75	35	110	303	138	441
10	121	100	221	482	400	882
15	88	133	221	352	530	882
20	59	162	221	236	646	882
25	37	184	221	148	734	882
30	22	199	221	88	794	882

Table 6.43 shows the maximum population impacts associated with transient and permanent construction workers and permanent production workers for the three representative regions. As noted above, the three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels, and the projected local and regional impacts presented here are intended to provide order-of-magnitude estimates for the range of potential impacts. In constructing Table 6.43 it was assumed, as discussed above, that a portion of the construction workers would be temporary, transient residents in an area and would not be accompanied by members of their households. The remainder of the construction workers would be permanent residents. The proportion of permanent workers to transient workers would gradually increase over time. All production workers are assumed to be permanent residents and would relocate their families to the area. Since the households of permanent construction and production workers are assumed to be the same size as average households in their respective regions, permanent workers are assumed to be accompanied by an average of 1.47 family members in Region A, 1.52 family members in Region B, and 1.49 family workers in Region C.

Table 6.43 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
A	340,555	Low	1,205	0.4%	7,111	2.1%
		Average	4,820	1.4%	28,447	8.4%
B	187,786	Low	554	0.3%	3,339	1.8%
		Average	2,217	1.2%	13,348	7.1%
C	215,222	Low	121	<0.1%	720	0.3%
		Average	482	0.2%	2,868	1.3%

Notes:

1 Existing population from US Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

The upper bound of the potential impacts is found in Region A under the average development scenario, when in Year 10 there are projected to be 4,820 unaccompanied transient workers, representing 1.4% of the region's total population. The upper bound of the potential impacts from permanent population changes can be found in Region A under the average development scenario in Year 30, when 28,447 permanent construction and production workers and their household members would be residing in the region. This figure represents 8.4% of the existing population in Region A. According to the population projections presented in Section 2.3.11, in the absence of gas well development, Region A is expected to experience a future population decrease and to have a 2030 population of 279,675 persons, a decrease of 60,880 persons, equal to 17.9% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 28,447persons in Year 30 under the average development scenario, would offset approximately 47% of the projected population decline in Region A and would, therefore, have a beneficial impact.

Under the average development scenario, Region B is projected to have a maximum of 2,217 unaccompanied, transient construction workers and 13,348 permanent construction and production workers and their family members residing in the region. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. The maximum transient population would account for 1.2% of the existing population in Region B, and the maximum permanent population would account for 7.1% of the existing population, respectively. According to population projection figures presented in Section 2.34.11, in the absence of gas well development, Region B is expected to experience a future population decrease and to have a 2030 population of 183,031 persons, a decrease of 4,755 persons, equal to 2.5% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 13,348 persons in Year 30 under the average development scenario, would more than offset the projected population decline in Region B but would not add significantly to the existing population.

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.3.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.

Because natural gas wells would not be evenly distributed across the regions, there may be more significant localized population impacts. Depending on the distribution of the wells and the phasing of well development, which depends partly on the price of natural gas, shale gas production may create localized growth in individual small towns. Also, because the development of new wells would not be distributed evenly over time due to swings in well development activity, downswings may cause periods of smaller-than-projected population impacts, while upswings may cause larger-than-projected population impacts.

6.8.3 Housing

This section describes the potential impacts on housing resources and property values that could result from the development of natural gas reserves in low-permeability shale in New York State. Statewide and regional impacts are discussed separately in the following section. For the purposes of this analysis, three representative regions were selected to examine the range of potential regional impacts. This analysis in no way is meant to imply that impacts would occur only in these three regions. Local- and regional-level impacts would occur wherever high-volume hydraulic fracturing wells are constructed. Currently, the actual locations of these wells have not yet been determined, and wells could be sited anywhere there is low-permeability shale. As described in previous sections, two development scenarios were analyzed for a 60-year period. Only the impacts that would occur during maximum build-out conditions (Year 10 for the transient workers and Year 30 for the permanent workers) are presented in this SGEIS. Impacts for all other years are presented in the Economic Assessment Report.

6.8.3.1 New York State

As previously described in Section 6.8.1 (Economy, Employment, and Income), total construction employment in New York State that would result from the development of low-permeability natural gas reserves is projected to range from 4,408 new workers under the low development scenario to 17,634 new workers under the average development scenario. Initially, the majority of the construction workers are assumed to be temporary, transient workers. As the natural gas fields are developed over time, it is assumed that an increasing number of these workers would become permanent residents. Production employment is projected to range from 1,790 workers under the low development scenario to 7,161 workers under the average development scenario.

Table 6.44 presents estimates of the maximum temporary, transient employment that would occur in Year 10 and the maximum permanent employment that would occur in Year 30. Transient employment includes those construction workers who would only temporarily relocate to the area during well construction. Permanent employment includes permanent construction workers and permanent production workers, as discussed more fully in Section 6.8.2, Population.

Table 6.44 - Maximum[1] Estimated Employment by Development Scenario for New York State (New August 2011)

Development Scenario	Transient Employment (FTE)	Permanent[2] Employment (FTE)
Low	2,409	5,757
Average	9,639	23,032

1 Maximum transient employment occurs in Year 10, while maximum permanent employment occurs in Year 30.

2 Permanent employment includes both permanent construction and production employment.

Note: Maximum transient employment and maximum permanent employment are reached in two different years. Therefore, the figures for transient employment and permanent employment in this table cannot be added to equal total employment. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for year-by-year employment details.

Temporary Housing

The construction phase is expected to have a short-term impact on temporary housing resources in New York State. New York State is currently not a major oil or gas producing state and, therefore, does not have a large work force skilled in oil and natural gas extraction. Thus, it is anticipated that workers specialized in gas exploration and drilling would travel into New York from other states where gas exploration and drilling is more significant. In the beginning, much of the workforce would need to be imported from other states. Over time, an experienced workforce would be created within New York, and the need for out-of-state workers would decline.

Typically, construction of a high-volume hydraulic fracturing well is completed in 3 to 4 months. Therefore, the transient workers needed to drill these wells would likely only temporarily relocate to a specific area, and once that well was completed they would move on to another site. The influx of workers who would move from one well development site to another would increase the demand for transient housing, such as rental properties and hotel/motel rooms, thereby decreasing the rental and hotel/motel vacancy rates within the state. Decreased rental and hotel/motel vacancy rates would provide short-term economic benefits to some owners of rental housing and hotels/motels within the state and in certain areas may increase prices charged for these temporary housing units.

Table 6.45 identifies the total stock of rental housing units, the existing supply of vacant housing units for rent, and the rental vacancy rate in New York State as a whole. Assuming a worst-case scenario where each projected transient construction worker would require one rental-housing unit, New York State as a whole could easily supply rental housing to construction workers under all development scenarios with existing vacant units at maximum build-out. Therefore, the impact on the supply of rental housing resources during the construction phase would be negligible at the statewide level. Impacts at a the regional and local levels are discussed below.

Table 6.45 - New York State Rental Housing Stock (2010) (New August 2011)

Total Rental Inventory	**For Rent**	**Rental Vacancy Rate (%)**
3,632,743	200,039	5.5

Source: USCB 2010.

Permanent Housing

Some migration of workers into New York State would be expected to occur as a result of the construction and production phase of the high-volume hydraulic fracturing operations. Initially, there would not be enough workers specialized in gas production to meet the demand. Therefore, it would be expected that these workers would move into New York State from states where the natural gas extraction industry is more developed. However, over time, an experienced workforce would be created within the state, and the need for out-of-state workers would decline.

Table 6.46 identifies the existing supply of vacant housing units for sale or rent in New York State. Seasonal, recreational, and occasional-use units and units rented or sold but not occupied were not included in these totals. Assuming a worst-case scenario at maximum build-out, it is anticipated that each projected permanent construction and production worker would require one permanent housing unit. Given that assumption, New York State has more than enough houses for sale to provide permanent housing units to the new permanent workers. Therefore, the impact on the supply of permanent housing units would be negligible at the statewide level.

Table 6.46 - Availability of Owner-Occupied Housing Units (2010) (New August 2011)

Total Number of Housing Units	For Sale	For Rent
8,108,103	77,225	200,039

Source: USCB 2010.

Based on the above discussion, it can be concluded that at the statewide level, New York State as a whole has a more than sufficient supply of rental properties and housing units to cope with the additional workers employed under each of the development scenarios at maximum build-out in Year 30. Regional and local impacts are discussed below.

6.8.3.2 Representative Regions

Table 6.47 identifies the maximum transient and permanent employment in Regions A, B, and C. See Section 6.8.1 and 6.8.2 for a detailed discussion of the derivation of these numbers.

Table 6.47 - Maximum Transient and Permanent Employment by Development Scenario and Region (New August 2011)

Region	Maximum Transient Employment (in FTE)[1]	Maximum Permanent Employment[2]
Region A		
Low	1,205	2,879
Average	4,820	11,517
Region B		
Low	554	1,325
Average	2,217	5,297
Region C		
Low	121	289
Average	482	1,152

1 Maximum transient employment occurs in Year 10.

2 Maximum permanent employment occurs in Year 30 and includes both permanent construction and production employment.

Note: Maximum transient employment and maximum permanent employment are reached in two different years. Therefore, the figures for transient employment and permanent employment in this table cannot be added to equal total employment. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report, for year-by-year employment details.

Temporary Housing

The construction phase would be expected to have a short-term, mixed impact on the rental housing stock in the representative regions. As described above, given the short-term nature of well construction, it is unlikely that many of the construction workers would initially permanently relocate to the region. However, as the natural gas development industry developed in the region and long-term employment became more likely, more construction workers would choose to permanently relocate to the regions.

In most cases, transient construction workers would temporarily reside in nearby population centers and commute to the development sites. Once the well is completed, they would move on to another area. The influx of a large number of transient construction workers into these regions would be expected to increase the demand for temporary housing, such as rental properties, hotel/motel rooms, and RV camp sites, thereby decreasing rental and hotel/motel vacancy rates throughout the region. Decreased rental and hotel/motel vacancy rates are expected to provide short-term economic benefits to some owners of rental housing and hotels/motels in these regions, but it could also cause a shortage of temporary housing in the most affected areas. The increase in demand may also increase the price charged for these units.

In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers (Kelsey 2011). There have been reports of large increases in rent in Bradford County, Pennsylvania, as a result of the influx of out-of-area workers (Lowenstein 2010). There have also been "frequent reports" of landlords not renewing leases with existing tenants in anticipation of leasing at higher rates to incoming workers, and reports of an increased demand for motel and hotel rooms, increased demand at RV campsites and increases in home sales (Kelsey 2011). Such localized increases in the demand for housing have raised concerns about the difficulties caused for existing local, low-income residents to afford housing (Kelsey 2011).

The impacts on temporary housing described above for Bradford County, while acute in the short-term, may decline in the long-term as more workers establish permanent residences in the area and as the market has time to respond to the shortage in temporary housing. As more hotel/motel rooms are constructed, and more rental properties become available, the shortages of existing units would decline and subsequently rental prices would also decline.

As with the situation in areas in Pennsylvania undergoing early Marcellus shale development, it is likely that most of the workers employed during the construction phase would relocate from outside of Regions A, B, and C, as natural gas well exploration and drilling require specialized skilled workers (Marcellus Shale Education and Training Center 2009).

Table 6.48 identifies the total rental inventory, the existing supply of vacant housing units for rent, the rental vacancy rate, and the number of hotel/motel rooms in Regions A, B, and C. Assuming a worst-case scenario, where each incoming temporary worker would require one rental housing unit or hotel/motel room at maximum transient employment levels (Year 10), Regions B and C have more vacant rental units than incoming workers under both scenarios. Region A also has more hotel/motel rooms and vacant rental units than the number of incoming workers under both development scenarios. However, the average development scenario would utilize the majority (69.5%) of the rental properties and hotel/motel rooms in Region A, thereby, causing shortages for the existing renters/ hotel users.

Table 6.48 - Availability of Rental Housing Units (New August 2011)

Region	Total Rental Inventory	For Rent	Rental Vacancy Rate (%)	Hotel/Motel Rooms
Region A	48,955	3,824	7.8	3,110
Region B	24,558	2,604	10.6	3,705
Region C	29,127	2,624	9.0	1,987

Source: USCB 2009.

In Regions B and C under both development scenarios and in Regions A under the low development scenario, the existing stock of rental housing is sufficient to meet the needs of incoming workers; thus, no additional rental housing would need to be constructed. However, rent increases caused by the increased demand for rental housing could make such housing unaffordable for existing low-income tenants, and increased demand for hotel/motel rooms would be likely to cause price increases in these sectors.

Under the average development scenario, shortages of rental housing would likely occur in Region A. The use of seasonal, recreational, or occasional use housing units as rental properties could potentially reduce the impact of increased demand on rental housing in these regions. However, it is likely that rents and hotel/motel room rates would remain elevated until additional rental housing and motels/hotels were constructed to meet the higher level of demand. The higher rents would negatively impact existing low-income residents, who may not be able to find affordable rental housing within the regions. The higher motel/hotel rates and/or the fewer available rooms may discourage some visitors from coming to these regions and thereby have the potential to reduce tourism in those areas.

The above analysis was completed on a regional level and included all rental units in a two- or three-county area. However, temporary housing impacts may occur and be more severe at an even more local level. If several well pads were developed at the same the time in the same area, there would be an even larger concentration of workers and a greater demand for temporary housing in that immediate area and in the population centers located near the general vicinity of the development. Although data on commuting patterns by occupation show that temporary construction workers typically are willing to commute farther than other workers, there still could be a significant increase in local housing demand. Therefore, the localized impacts in areas where there is a high concentration of natural gas wells may be greater than those described above.

Permanent Housing

The permanent construction and production workers are expected to have a long-term, mixed impact on the permanent housing stock in the representative regions. Given the need to have natural gas operators with specialized skills, many of the production workers would relocate from areas outside the representative regions. New production workers recruited from outside the region would typically be offered permanent employment and would likely require permanent housing. In addition, as the natural gas industry expands in the representative regions and the long-term construction employment becomes more permanent in the region, more construction workers would choose to live permanently in the regions and simply commute between well sites. These additional construction and production workers would increase the demand for permanent housing. In addition, the increased economic activity that would take place in these regions as a result of natural gas development would further increase the demand for permanent housing and reduce homeowner and rental vacancy rates in the region.

Table 6.49 identifies the number of vacant permanent housing units for sale or rent in Regions A, B, and C. Seasonal, recreational, and occasional-use units and units rented or sold but not occupied were not included in this table. The following analysis assumes a worst-case scenario where all new permanent construction workers and all production workers would relocate to the region and require one permanent housing unit each at maximum build-out (Year 30) to purchase or rent. However, in actuality this may overstate the regional impacts. Many of the permanent worker positions could be filled by currently unemployed or underemployed workers from the local areas, thus reducing the overall demand for permanent housing.

Given this worse-case assumption, Regions A, B, and C would be able to absorb the additional demand for permanent housing units under the low development scenario. Regions A, B, and C would not be able to meet the increased demand for permanent housing units under the average development scenario.

Table 6.49 - Availability of Housing Units (New August 2011)

Region	Total Number of Housing Units	For Sale	For Rent
Region A	151,135	1,516	3,824
Region B	111,185	1,989	2,604
Region C	108,031	1,278	2,624

Source: USCB 2010.

No additions to the permanent housing stock would be required under the low development scenarios in which regions could absorb additional demand for permanent housing. However, it is expected that house prices would rise initially in response to the increased demand for permanent housing, resulting in difficulties for low-income residents seeking to buy a home and capital gains for owners of existing homes. In the long-term, additional housing construction would take place and prices would level off as the supply of housing units caught up with the demand for these units.

Under the average development scenario in which regions do not have enough homes for sale or rent to meet the potential demand from incoming permanent workers, the incoming workers and existing residents would compete for the existing stock of permanent housing units, resulting in an increase in housing prices. Over time, builders and landowners would respond to the higher prices by constructing more permanent housing units. However, before such homes are constructed, a period of particularly high prices would be expected. Low-income residents that do not already own property or currently rent might face difficulties in finding affordable homes to buy, and owners of existing homes would experience capital gains.

The above analysis was completed on a regional level and included all permanent housing units in a two- or three-county area. Permanent housing impacts may occur and be more severe on a more local level. If, for example, production workers are expected to report to only a few centralized facilities, the demand for permanent housing near these facilities would be greater than for the region as a whole. This may place a strain on the permanent housing stock in such areas, and the impacts may be even greater than those described above.

6.8.3.3 Cyclical Nature of the Natural Gas Industry

The demand for housing, both temporary and permanent, would be expected to change over time. The demand for housing would be the greatest in the period during which the wells in an area are being developed, and demand would decline thereafter. This would create the possibility of an excess supply of such housing after the well development period (Kelsey 2011). If well development in a region occurs in some areas earlier than in others, then housing shortages and surpluses may occur at the same time in different areas within the same region.

The natural gas market can be volatile, with large swings in well development activity. Downswings may cause periods of temporary housing surplus, while upswings may exacerbate housing shortages within the regions.

6.8.3.4 Property Values

At this level of analysis, it is impossible to predict the actual impacts of developing the Marcellus and Utica shale natural gas reserves on individual property values. However, some predictions can be made with regard to the general impact of mineral rights on property values and the impact of well development on adjacent properties.

Significant increases in property value are expected where the subsurface mineral rights and land are held jointly with land ownership and the exploitation of the subsurface resources is not limited in some way. Because the owners of subsurface mineral rights typically receive royalty payments equal to or greater than 12.5% of the total value of production, the development of natural gas reserves would be expected to substantially increase the value of their property. Properties where the mineral rights are not held jointly with land ownership, or where there is some restriction on drilling, would not experience this increase in value.

Property values could also be affected by the impacts associated with developing natural gas resources. Gas well development could impact local environmental resources and cause noise and vibration impacts, and trucks servicing the well development could also impact the surrounding areas. Once wells are in place, the local impacts would be less and there would be much less traffic moving to and from the wells. Pipelines would be constructed to carry the natural gas from the wells. Construction of the pipelines would have an impact on the landscape and would result in the maintenance of cleared rights-of-way once the pipeline is in place. Gas compressor stations would also be constructed to maintain the pressure of the gas in the pipelines, and there would be noise and air emissions associated with their operation.

It is possible that these various impacts, particularly those associated with the construction phase, could reduce the value of properties close to the wells relative to similar properties not located close to wells. In order to assess the potential impact these negative externalities would have on property values in the affected regions, a review of economic literature was undertaken. A number of studies have been conducted to provide quantitative estimates of the impact of wells on property values. These studies are discussed and reviewed below. As with much economic and econometric literature, the following studies are based on data gathered for specific geographical locations at specific times. While the findings of these studies are analogous to the current situation discussed in this SGEIS, the findings should only be used as an indication of direction and the magnitude of possible impacts on property values. Characteristics of individual housing markets and the nature of the gas development activities would vary dramatically from site to site, thus the findings in the following reports should not be viewed as an actual estimate of impacts. BBC Research and Consulting (2001) examined the impact of coal bed methane wells on property values in La Plata County, Colorado, between 1989 and the first half of 2000. The authors used a hedonic approach (i.e., an approach that links property values to their attributes and the attributes of surrounding areas) to estimate the impact of having a well on a property and having a well near to, but not on, a property. The authors found that having a well on a property was associated with a 22% reduction in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. The authors attributed the positive impact on property values of having a well located within 550 feet of a property to the prevention of further gas well development in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells (BBC Research and Consulting 2001).

Boxall, Chan, and McMillan (2005) examined the impact of small to medium size oil and gas production facilities on rural residential property values using data from central Alberta, Canada. In this study, the authors found a statistically significant negative relationship between property values and the presence of oil and gas facilities within approximately of 2.5 miles of rural residential properties. The presence of oil and gas facilities within 2.5 miles of rural residential properties was estimated to reduce property values between 4% and 8%, with the potential to double the impact, depending on the level and composition of the nearby industry activities (Boxall et al. 2005).

Integra Realty Resources (2011) conducted a study of the impact of natural gas wells on property values in and around Flower Mound, a community approximately 28 miles northwest of downtown Dallas, Texas, where gas drilling is a recent development. The authors used four methods to estimate the impact of wells on property values: (1) examining the relationship between distance to a well site and property values; (2) comparing the sales prices of properties close to a well and comparable properties not close to a well; (3) a statistical analysis of the relationship between property attributes, including proximity to a well and values; and (4) surveying market participants (principally realty agents). With regard to the relationship between the distance between properties and well sites, they found that within Flower Mound itself there was a negative impact on property values when houses are immediately adjacent to well sites; however, this negative impact diminishes quickly with increasing distance from the well. The impact was found to be between -2% and -7% of property values. The results of the comparable sales analysis indicated that, in most cases, there was little correlation between proximity to a well site and property values. However, within Flower Mound itself and for properties in excess of $250,000 in selling price, proximity to a well had a negative impact of between -3% and -14% on property values. The statistical analysis found no statistically significant relationship between property values and proximity to a well site. Finally, market participants reported that proximity to a well site had an impact on the time required to sell a property; however, this impact was most pronounced during the actual process of well development and diminished thereafter (Integra Realty Resources 2011).

Fruits (2005) studied the impact of the South Mist Pipeline Extension on residential property values in Clackamas and Washington counties, Oregon. In his analysis, Fruits performed three statistical tests using the hedonic housing price approach and found no statistically significant impact from natural gas pipeline development on residential property values (Fruits 2005).

Palmer (2008) also looked at the impact of the South Mist Pipeline Extension on residential property values in Clackamas and Washington counties, Oregon. Palmer, working on behalf of Palomar Gas Transmission LLC, conducted a market study using data from 2004 to 2008 that compared sales of properties along pipeline corridors with comparable sales of non-affected properties. Palmer found no measurable impact on property values resulting from the construction and operation of natural gas pipelines (Palmer 2008).

In conclusion, the above literature review suggests that being in proximity to a well could reduce the value of a property, but that proximity to a gas pipeline might not reduce the value of a property. The proposed natural gas development would have an overall regional effect of increasing property values due to the expected in-migration of construction and operations workers and the increased economic activity that would occur in the area. Likewise, properties that still included unexploited sub-surface mineral rights would increase in value due to the potential of receiving royalty payments. However, not all properties in the region would increase in value, as residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights.

6.8.4 Government Revenue and Expenditures

This section discusses the potential fiscal impacts on state and local government entities that would occur as a result of the proposed development of low-permeability shale natural gas reserves. Impacts on major revenue sources for the state and local governments are discussed, as are expected changes in state and local government expenditures that could occur as a result of the use of the high-volume hydraulic-fracturing technique.

Given the uncertainty associated with the actual level of future development of these reserves, the rate of extraction that would occur, and the actual geographic location where development would take place, it is impossible to definitively quantify the fiscal impacts of this action. However, some estimates have been made. These estimates should be viewed only as order-of-magnitude estimates and not as actual revenue or cost projections.

6.8.4.1 New York State

The proposed high-volume hydraulic fracturing operations would have a significant positive impact on revenues collected by New York State. Revenues in the state would increase directly as a result of lease payments for natural gas development that would occur under state-owned land and indirectly from an increase in tax revenues generated by the natural gas development and the resulting increase in economic activity throughout the state. No surface access would be granted for high-volume hydraulic fracturing operations on most state-owned lands. However, the subsurface natural gas deposits under state-owned lands could be accessed by surface operations located on privately owned lands. If the subsurface natural gas deposits under state-owned lands were extracted, New York State would receive lease payments and royalties for the mineral rights.

Currently, New York State receives lease payments for any existing or planned natural gas development on state-owned lands that are leased. These payments would also be received for any new subsurface mineral rights that are leased and/or any new wells drilled in the low-permeability shale that would access subsurface natural gas reserves under state-owned lands.

Delay rentals (i.e., rental payments that are provided to the owner of the mineral rights before drilling and production occurs) and bonus bid payments would accrue to the state when developers first purchase the right to exploit the subsurface minerals under state-owned lands. Royalty payments of 12.5% or more of gross revenues would also be provided to the state for any natural gas reserves extracted from under state-owned lands.

At this point in the planning processes it is impossible to accurately assess the exact location where these wells would be drilled and whether or not these wells would be located on private lands that could access underground reserves under state-owned lands. Therefore, it is impossible to estimate the total royalty and lease payments that would accrue to the state. However, these payments are not expected to be large relative to the total New York State budget. Currently, New York State receives approximately $746,000 in lease payments per year for all oil and natural gas developments on state-owned lands.

The state would indirectly receive a significant increase in its revenue streams as a result of the proposed drilling in low-permeability shale. As described in Section 6.8.1 (Economy, Employment, and Income), high-volume hydraulic fracturing operations would increase employment and income throughout the state. Up to $621.9 million to $2.5 billion in employee earnings would be directly and indirectly generated per year at maximum build-out, depending on the development scenario.

As a result, New York State would experience a large increase in its personal income tax receipts. In 2008 the effective personal income tax rate for all taxpayers in New York State was 5.0%. If this tax rate were used for estimation purposes, at maximum build-out the state could receive between $31 million and $125 million a year in personal income tax receipts, depending on the level of development assumed.

In addition to the personal income tax, the state would also experience some increase in its corporate tax receipts. Corporate income in the state would increase both directly, as the natural gas developers profit from the extraction of the gas in the low-permeability shale, and indirectly due to the resulting increase in economic activity in the state. However, given the many benefits in the New York State tax code for energy companies, such as expensing, depletion and depreciation deductions, the taxable income from the natural gas industry would be greatly reduced. In addition, New York State offers an investment tax credit (ITC) that could substantially reduce most, if not, all of the net income generated by these energy development companies. Also the sale of the natural gas generated by these companies may not take place in New York and, therefore, may not be subject to New York State corporate tax (NYSDTF 2011a).

Other tax receipts would also increase. Revenues generated from sales and use tax would also register an increase as industry purchased the materials needed to develop these natural gas reserves that are not exempt from state and local sales tax. However, many of the materials needed to construct these wells would be tax-exempt, including such things as piping, drill rigs, service rigs, vehicles, tools and supplies, pollution control equipment, and services to real property (NYSDTF 2011a).

The direct, indirect, and induced economic activity associated with the high-volume hydraulic fracturing would further expand sales tax receipts as the new workers spend a portion of the increased earnings in the state.

High-volume hydraulic fracturing operations would also result in some significant negative fiscal impacts on the state. The increased truck traffic required to deliver equipment, supplies, and water and sand to the well sites would increase the rate of deterioration of the state's road system. Additional capital outlays would be required to maintain the same level of service on these roads for their projected useful life. Depending on the exact location of well pads, the state may also be required to upgrade roads and interchanges under its jurisdiction in order to handle the additional truck traffic. The potential increase in accidents and possible additional hazardous materials spills resulting from the increased truck traffic also would require additional expenditures. Finally, approval of transportation plans/permits would place additional administrative costs on the New York State Department of Transportation.

Additional environmental monitoring, oversight, and permitting costs would also accrue to the state. In order to protect human health and the environment, New York State would be required to spend substantial funds to review permit applications, to ensure that permit requirements were met, safe drilling techniques were used, and best available management plans were followed, and to enforce against violations. In addition, the state would experience administrative costs associated with the review of well permit applications and leasing requirements, and enforcement of regulations and permit restrictions. All of these factors could result in significant added costs for New York State's government.

6.8.4.2 Representative Regions

Development of the natural gas reserves would have a significant fiscal impact on local governments wherever drilling would take place. These impacts would be both positive and negative in nature. As described above, local government entities who take part in sales tax revenue sharing schemes would experience a substantial increase in sales tax receipts as a result of the additional economic activity that would occur within their jurisdictions. Local government entities that receive proceeds from ad valorem property taxes would see significant increases to their tax rolls and property tax receipts.

As described previously in Section 2.3.11.4, Government Revenues and Expenditures, producing natural gas wells are taxable for ad valorem real property tax purposes in New York State. Therefore, every new natural gas well operating in a local government's jurisdiction would increase that government's tax base and the total assessed value of property.

In New York State, producing natural gas wells are taxed based on the value of their production for ad valorem property tax purposes. Each year the New York State Office of Real Property Tax Service determines the "unit of production value" for a region. This unit value is then multiplied by the total amount of natural gas produced, and the state equalization rate is then applied to determine the total assessed value of the natural gas well. Applicable property tax rates are then applied to this assessed value to determine the ad valorem property tax levy. See Section 2.3.11.4, Government Revenues and Expenditures, for more details.

Using the above-mentioned formula, an estimate of local property tax revenues can be generated and extrapolated for each development scenario. Using industry estimates for the productivity of horizontal and vertical high-volume hydraulic fracturing wells, the following property tax analysis has been completed for Year 30, the year of maximum impact. See the Economic

Assessment Report for a more detailed discussion of the methodology used to estimate property tax impacts and to see data for other years.

In order to predict the change in property tax revenues that would result from the proposed development of the low-permeability shale natural gas reserves, annual production of the wells was forecasted. Many factors affect the annual production of a natural gas well. Typically, production initially starts out at a maximum level and then declines quickly until it reaches a slower rate of decline. Production then continues at this lower level for approximately 30 years. Horizontal high-volume hydraulic-fracturing wells produce more natural gas than vertical high-volume hydraulic-fracturing wells. This discrepancy has been accounted for in the analysis. For a more detailed description of projected production levels, see the Economic Assessment Report.

For the purposes of this analysis, the 2010 unit of production value for the Medina formation was used to estimate the real property tax payments of a representative horizontal high-volume hydraulic fracturing well in Broome County. When the Marcellus Shale and Utica Shale reserves are developed in New York State, specific unit of production values would be developed for that specific formation and the specific drilling techniques used in that formation. Depending on the results of that analysis, the unit of production value could vary substantially from the Medina values utilized in this report. Table 6.50 shows the estimated annual real property tax payments for a typical high-volume hydraulic-fracturing horizontal well in Broome County in each year of its operational life using the Medina formation unit of production value. See the Economic Assessment Report for additional examples.

Table 6.50 - Example of the Real Property Tax Payments From a Typical Horizontal Well (New August 2011)

County:			**Broome**
2010 Final Gas Unit of Production Value			$11.19
2010 Overall Full-Value Tax Rate[1]			35.5
Production Year	**Annual Production (millions of cubic feet)**	**Assessed Value of Production[2]**	**Property Tax Payment[3]**
1	803.00	$8,985,570	$318,988
2	354.05	$3,961,820	$140,645
3	258.00	$2,887,020	$102,489
4	201.43	$2,253,946	$80,015
5	165.93	$1,856,701	$65,913
6	144.50	$1,616,955	$57,402
7	130.00	$1,454,700	$51,642
8	119.00	$1,331,610	$47,272
9	109.93	$1,230,061	$43,667
10	103.20	$1,154,850	$40,997
11	98.04	$1,097,107	$38,947
12	93.14	$1,042,252	$37,000
13	88.48	$990,139	$35,150
14	84.06	$940,633	$33,392
15	79.86	$893,601	$31,723
16	75.86	$848,921	$30,137
17	72.07	$806,475	$28,630
18	68.47	$766,151	$27,198
19	65.04	$727,844	$25,838
20	61.79	$691,451	$24,547
21	58.70	$656,879	$23,319
22	55.77	$624,035	$22,153
23	52.98	$592,833	$21,046
24	50.33	$563,191	$19,993
25	47.81	$535,032	$18,994
26	45.42	$508,280	$18,044
27	43.15	$482,866	$17,142
28	40.99	$458,723	$16,285
29	38.94	$435,787	$15,470
30	37.00	$413,997	$14,697
Total Property Tax Payments for the Productive Life of the Well			**$1,448,735**

Sources: NYSDTF 2011b, 2011c, 2011d, 2011e; All Consulting 2011.

Notes:

1 Full-value tax rates are tax rates that have been already been equalized. Therefore, these numbers should not be multiplied by the state equalization rate.

2 Calculated as Annual Production multiplied by 1,000 (to calculate the number of 1,000s of cubic feet) multiplied by the 2010 Final Gas Unit of Production Value (applied to each 1,000 cubic feet).

3 Calculated as Assessed Value multiplied by the Overall Full-Value Tax Rate divided by 1,000.

In estimating real property tax payments for vertical high-volume hydraulic fracturing wells it was initially assumed that each well would produce at the same average level of production as existing wells (in 2009) in the region. However, average annual production for existing wells in Region A was approximately 317.9 million cubic feet per year. This figure was deemed to be too optimistic, so a figure of 90 million cubic feet per year was used instead for Region A production. The 90 million cubic feet per year corresponds to production levels of vertical wells currently operating in the Marcellus formation in Pennsylvania (NYSDEC 2011). Region B currently has no producing natural gas wells, and its Marcellus and Utica Shale formations are similar to those found in Region A (NYSDEC 2011). Therefore, a production level of 90 million cubic feet per year was also used for Region B. In contrast, due to the geological characteristics of Region C, high-volume hydraulic fracturing vertical wells are not anticipated to have the same level of production as in Region A or Region B. High-volume, hydraulic fracturing vertical wells in Region C are anticipated to have production levels similar to other vertical wells currently operating in the region (NYSDEC 2011). Therefore, in Region C it is assumed that each well would produce at the same average level of production as existing wells (in 2009) in the region.

Table 6.51 shows the estimated annual real property tax payment from a typical vertical well. The example uses the overall full-value tax rate, which averages the property tax levies in Broome County from all taxing jurisdictions, including county, town, village, school district, and other taxing districts, and the 2010 Medina formation unit of production value. As described previously, once Marcellus Shale or Utica Shale formations become developed in New York State, specific unit of production values would be developed for that specific formation and the specific drilling techniques used in that formation. Depending on the results of that analysis, the unit of production value could vary substantially from the Medina values utilized in this report.

Table 6.51 - Example of the Real Property Tax Payments from a Typical Vertical Well (New August 2011)

County:	Broome
2010 Final Gas Unit of Production Value	$11.19
2010 Overall Full-Value Tax Rate	35.5
Annual Production (millions of cubic feet)	90
Assessed Value of Production of Well[1]	$1,007,100
Annual Property Tax Payment[2]	$35,752

Source: NYSDTF 2011b, 2011c, 2011d, 2011e; NYSDEC 1994-2006, 2007b, 2008, 2009.

Notes:

1 Calculated as Annual Production multiplied by 1,000 (to calculate the number of 1,000s of cubic feet) multiplied by the Final Gas Unit of Production Value (applied to each 1,000 cubic feet).

2 Calculated as Assessed Value of Production of Well multiplied by the Overall Full-Value Tax Rate divided by 1,000.

As shown on Table 6.52, the projected change in total assessed value and property tax receipts that would result under any of the development scenarios would be significant. Annual property tax receipts at the peak production year (Year 30) would range from $9.1 million in Chautauqua County to $77.5 million in Broome County under the low development scenario. For Year 30, annual property tax receipts under the average development scenario would range from $35.4 million in Chautauqua County to $309.3 million in Broome County, and annual property tax receipts under the high development scenario would range from $53.1 million in Chautauqua County to $460.0 million in Broome County (see Table 6.52).

Table 6.52 - Projected Change in Total Assessed Value and Property Tax Receipts[1] at Peak Production (Year 30), by Region (New August 2011)

	Low Development Scenario		**Average Development Scenario**	
	Change in Assessed Value ($ million)	**Total Property Tax Receipts ($ million)**	**Change in Assessed Value ($ million)**	**Total Property Tax Receipts ($ million)**
Region A				
Broome County	$3,345	$119	$13,342	$474
Chemung County	$1,930	$66	$7,700	$264
Tioga County	$2,458	$76	$9,803	$302
Total Region A	$7,732	$261	$30,845	$1,040
Region B				
Delaware County	$1,498	$32	$5,996	$127
Otsego County	$1,040	$20	$4,164	$82
Sullivan County	$1,006	$26	$4,024	$105
Total Region B	$3,544	$78	$14,184	$314

	Low Development Scenario		Average Development Scenario	
	Change in Assessed Value ($ million)	**Total Property Tax Receipts ($ million)**	**Change in Assessed Value ($ million)**	**Total Property Tax Receipts ($ million)**
Region C				
Cattaraugus County	$406	$14	$1,583	$56
Chautauqua County	$329	$11	$1,283	$41
Total Region C	$735	$25	$2,866	$97
Total Regions A, B, and C	$42,856	$364	$47,895	$1,451

Source: NYSDTF 2011b, 2011c, 2011d, 2011e.

[1] Property tax receipts are calculated using the overall full-value tax rate for each county. Therefore, the property tax receipts figure estimates property taxes collected from all levels of government, including county, town, village, school district, and other special taxing districts.

Note: Totals may not sum due to rounding.

The increase in ad valorem property taxes would have a significant positive impact on the finances of local government entities. While these figures are not directly comparable to the current county revenues and expenditures data presented in Section 2.3.11.4, Government Revenue and Expenditures, the figures can be used to show the order of magnitude of these impacts. The total property tax receipts shown above were calculated using the overall full-value tax rate, meaning the impact figures presented above include town, village, school district, and other special taxing districts revenue as well county property tax receipts.

In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts resulting from the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also additional expenditures on public water supply systems may also be required. Finally, if substantial in-migration occurs in the region as a result of drilling and production, local governments would be required to increase expenditures on other services, such as education, health and welfare, recreation, housing, and solid waste management to serve the additional population.

6.8.5 Environmental Justice

As described in previous sections, there is potential for some localized negative impacts to occur as a result of allowing high-volume hydraulic fracturing. Therefore, implementation of such projects could have localized negative impacts on environmental justice populations if the projects are sited in identified environmental justice areas. However, specific project site locations have not been selected at this time.

Currently, natural gas well permit applications are exempt from requirements in NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29); therefore, additional environmental justice screening would not be required for individual well permit applications. However, some of the auxiliary permits/approvals that would be needed prior to well construction may require environmental justice screening.

When necessary, project applicants would determine whether the proposed project area is urban or rural and would perform a geographic information system (GIS)-based analysis at the census tract or block group level to identify potential environmental justice areas. If a potential environmental justice area is identified by the preliminary screening, additional community outreach activities would be required.

6.9 Visual Impacts[402]

The visual impacts associated with vertical drilling in the Marcellus and Utica Shales would be similar to those discussed in the 1992 GEIS (NYSDEC 1992). Horizontal drilling and high-volume hydraulic fracturing are, in general, similar to those discussed in the 1992 GEIS (NYSDEC 1992), although changes that have occurred in the industry over the last 19 years may affect visual impacts. These visual impacts would typically result from the introduction of new landscape features into the existing settings surrounding well pad locations that are inconsistent with (i.e., different from) existing landscape features in material, form, and function. The

[402] Section 6.9, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

introduction of these new landscape features would result in changes to visual resources or visually sensitive areas and would be perceived as negative or detrimental by regulating agencies and/or the viewing public.

The visual impacts of horizontal drilling and high-volume hydraulic fracturing would result from four general on-site processes associated with the development of viable well locations: construction, well development (drilling and fracturing), operation or production, and post-production reclamation. The greatest visual impacts would be associated with the construction of well pads and associated facilities, which would create new long-term features within surrounding landscapes, and well drilling and completion activities at viable well locations, which would be temporary and short-term in nature. Additional off-site activities could also result in visual impacts, including the presence of increased workforce personnel and vehicular traffic, and the use of existing or development of new off-site staging areas or contractor/storage yards.

The visual impacts of horizontal drilling and hydraulic fracturing would vary depending on topographic conditions, vegetation characteristics, the time of year, the time of day, and the distance of one or more well sites from visual resources, visually sensitive areas, or other visual receptors.

6.9.1 Changes since Publication of the 1992 GEIS that Affect the Assessment of Visual Impacts

A number of changes to equipment and drilling procedures since the 1992 GEIS have the potential to result in visual impacts over a larger surrounding area and/or visual impacts over a longer period of time. These changes can generally be separated into three categories: changes in equipment and drilling techniques; changes in the size of well pads; and changes in the nature and duration of drilling and hydraulic-fracturing activities.

6.9.1.1 Equipment and Drilling Techniques

The 1992 GEIS stated that drill rigs ranged in height from 30 feet for a small cable tool rig to 100 feet or greater for a large rotary rig. By comparison, the rigs currently used by the industry for horizontal drilling can be 140 feet or greater in height and have more supporting equipment. While a substantial amount of on-site equipment, including stationary tanks, compressors, and trucks, would be periodically present at each site during specific times of well development (drilling and fracturing), the amount of necessary on-site equipment during these times is similar to that addressed in the 1992 GEIS.

6.9.1.2 Changes in Well Pad Size and the Number of Water Storage Sites

The typical area that would undergo site clearing for an individual well pad has increased since 1992, from approximately 2 acres per site to an average of approximately 3.5 acres per site. The pad size was increased to accommodate the necessary on-site equipment for drilling and hydraulic-fracturing activities and to accommodate drill sites with multiple well pads. Since multiple wells can be drilled from the same pad, this change has resulted in fewer, but larger pads.

In addition, separate large areas for water storage are often developed in the vicinity of well pad sites. These areas look somewhat similar to well pads because of their overall size and because of the presence of specific types of equipment (primarily tanks and trucks). However, they may contain specific landscape features associated with water procurement or storage features, including large graveled areas for truck traffic, water impoundment areas, and water storage tanks that are positioned on-site as needed.

6.9.1.3 Duration and Nature of Drilling and Hydraulic-Fracturing Activities

Since 1992 there have been a number of changes in the duration of drilling and hydraulic fracturing. In the 1992 GEIS, drilling time was described as an approximately one- to two-week or longer period, and there was no mention of the time required for hydraulic fracturing (NTC 2011). Currently, to complete a horizontal well takes 4 to 5 weeks of drilling, including hydraulic fracturing.

Since 1992 the industry has been trending, where possible, toward the development of multi-well pads rather than single-well pads. Multi-well pads are slightly larger, but the equipment used is often the same. Based on current industry practice, a taller rig (170 feet in total height) with a larger footprint and substructure may be used to drill multiple wells from a single pad. In some instances, smaller rigs may be used to drill the initial hole and conductor casing to just above the kick-off point, the depth at which a vertical borehole begins to turn into a horizontal borehole.

The larger rig is then used for the final horizontal portion of the hole. Typically, one or two wells are drilled and the rig is then removed.

If the well(s) are productive, the rig is brought back and the remaining wells are drilled and stimulated by the injection of hydraulic fracturing additives. There is the possibility that all wells on a pad would be drilled, stimulated, and completed consecutively, reducing the duration of visual impacts that would occur during drilling and hydraulic-fracturing activities. However, state law requires that all wells on a multi-well pad be drilled within three years of starting the first well (NTC 2011).

6.9.2 New Landscape Features Associated with the Different Phases of Horizontal Drilling and Hydraulic Fracturing

This section discusses the various visual impacts that may be associated with on-site horizontal drilling and high-volume hydraulic fracturing activities during the construction, development (drilling and fracturing), production, and reclamation phases. Visual impacts would occur in the vicinity of the different sites associated with horizontal drilling and hydraulic fracturing, such as at well pads, water impoundment and extraction sites, and the large equipment that may be present on these sites (e.g., drilling rigs), as well as at the locations of off-site areas such as contractor/equipment storage yards and staging areas, pipeline and compressor station locations, gravel pits, and disposal areas (Rumbach 2011). Additional off-site activities that may result in impacts on visual resources or visually sensitive areas during one or more of these phases are discussed in Section 6.9.3.

6.9.2.1 New Landscape Features Associated with the Construction of Well Pads

New landscape features that would be associated with the construction of well sites include open, level areas averaging approximately 3.5 acres in size that would serve as the well pad; construction equipment, including bulldozers, graders, backhoes, and other large equipment to construct level areas using clearing, cutting, filling and grading techniques; trucks for hauling equipment and materials; and worker vehicles. Newly created sites would appear as open, level areas with newly exposed earthen areas, albeit mulched or otherwise protected for erosion control, similar to the appearance of the construction activities for a water impoundment area as shown in Photo 5.22 in Section 5.7.2.

Photo 6.1 below shows a well site where wells have already been drilled and completion operations are underway. The photograph shows evidence of grading, cutting, and filling activities; the use of gravel for site preparation; and mulching along an earthen embankment to prevent erosion—all activities implemented during construction activities. A portion of a newly created linear right-of-way for a connecting pipeline is shown on the hillside in the background of the photo. The red and blue tanks shown in Photo 6.1 are discussed in greater detail in Section 6.9.2.2.

Photo 6.1 - A representative view of completion activities at a recently constructed well pad (New August 2011)

Photo 6.2 below shows the same recently constructed well pad that is currently under development, but from a different angle. In the foreground of the photograph below, the newly created access road leading to the well pad is shown. Erosion control measures and materials are also shown in the photograph, including channeling, gravel fill and hay bales in the channel, and mulching on topsoil or spoil piles to the left of the access road to minimize erosion. Additional

views of access roads are presented in Photos 5.1 through 5.4 in Section 5.1.1 and in Photo 6.2. Tanks, vehicles, and other equipment are discussed in greater detail in Section 6.9.2.2.

Photo 6.2 - A representative view of completion activities at a recently constructed well pad, showing a newly created access road in foreground (New August 2011)

If water impoundment sites are necessary, they would be located in the same general area as well sites, approximately the same size as a well site, and also be generally level. However, they would also contain one or more large earthen embankments encircling plastic-lined ponds. See Photo 6.3 below. Photos 5.20 and 5.22 in Section 5.7.2 contain additional representative views of water impoundment sites.

Photo 6.3 - A representative view of a newly constructed water impoundment area (New August 2011)

If water procurement sites are necessary, such sites would be located near water withdrawal locations (typically rivers or other large sources of water) and would consist of large, newly created graveled areas sufficiently sized for tanker truck use and equipped with on-site water pumps and metering equipment, as shown in Photo 6.4. Photos 5.19a and 5.19b in Section 5.7.2 contain additional representative views of water procurement sites.

Photo 6.4 - A representative view of a water procurement site (New August 2011)

Additional areas associated with the construction of well sites would include newly created access roads and pipeline rights-of-way for connector pipelines (see Photo 6.1 and Photo 6.2). These sites would typically be narrow, linear features, as opposed to the large open areas needed for well pads and water impoundment or procurement sites.

6.9.2.2 New Landscape Features Associated with Drilling Activities at Well Pads

New landscape features that would be associated with drilling activities include drill rigs of various heights and dimensions, including the rotary rigs as described in the 1992 GEIS, with heights ranging from 40 to 45 feet for single rigs and 70 to 80 feet for double rigs. Currently, the industry also uses triple rigs that can be more than 100 feet in height. As discussed in Section 5.2.1, only the rig used to drill the horizontal portion of the well is likely to be significantly larger than what is described in the 1992 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 of about 14,000 square feet, which would include auxiliary equipment. Auxiliary equipment would include on-site tanks for holding water, fuel, and drilling mud; generators; compressors; solids control equipment (shale shaker, de-silter, desander); a choke manifold; an accumulator; pipe racks; and the crew's office space.

Photo 6.16, Photo 6.17, and Photo 6.20 show what a typical well pad may look like during the drilling of wells at a well pad. These photos show the industrial appearance of the well pad during the drilling phase, which would appear dramatically different from the pad's surrounding setting for the approximately 4- to 5-week duration of drilling activities.

6.9.2.3 New Landscape Features Associated with Hydraulic Fracturing Activities at Well Pads

New landscape features that would be associated with fracturing activities include an extensive array of equipment, which would cover almost the entire well pad. Photo 6.5 shows what a typical well site may look like during the hydraulic fracturing of wells at a well pad. This view is upslope of a well site that is under development. The photo shows the industrial appearance of the well site during the hydraulic fracturing phase, which would appear dramatically different from the site's surrounding setting for the 3- to 5-day duration of hydraulic fracturing activities. This view includes a water impoundment site (visible in the right background of the photo) and a portion of new right-of-way for a connector pipeline (visible on another hillside in the left background of the photo).

Photo 6.5 - A representative view of active high-volume hydraulic fracturing (New August 2011)

The equipment typically present during hydraulic fracturing includes the following:

- storage tanks that contain the water and additives used for hydraulic fracturing (rectangular red tanks on well site shown in Photo 6.5);
- tanks containing chemicals used in the fracturing process or for storage of liquefied natural gas produced during hydraulic fracturing (blue rectangular tanks on well site shown in Photo 6.5);
- compressors (large cylindrical blue equipment and smaller dark green equipment with stacks or vents shown in Photo 6.5) used for pumping product through various hoses and pipelines;
- miscellaneous trucks, including tractor trailers and other large trucks for hauling sand and hydraulic fracturing additives , pipe-hauling trucks, welding and other mechanical support trucks, and a crane; and
- miscellaneous worker vehicles (almost all of the white or silver vehicles shown in Photo 6.5).

6.9.2.4 New Landscape Features Associated with Production at Viable Well Sites

New landscape features associated with production at productive well sites would be relatively minimal. Following the establishment of viable wells, all of the fracturing equipment and vehicles shown in Photo 6.5 above would be removed from the site, and the site would be landscaped with either gravel or low-lying grassy vegetation. Some aboveground structures would be installed and remain on-site for the duration of production, including one or more wellheads, small storage tanks, and a metering system for the pipeline connections; however, these new aboveground structures would be small, less prominent landscape features, which over time would become part of the existing setting of the well site and its surrounding area. Photo 6.12, Photo 6.13, Photo 6.17, and Photo 6.20 at the end of Chapter 6 show the appearance of well sites during the production phase and the appearance of the same well sites during the earlier fracturing phase.

6.9.2.5 New Landscape Features Associated with the Reclamation of Well Sites

If well sites are restored to their original topographic configuration and vegetative cover, on-site aboveground structures associated with well production are removed and new landscape features are introduced. The new landscape features would temporarily include bare areas, which would be created by the large-scale earthmoving activity necessary to re-create the pre-existing terrain conditions, and newly placed erosion control materials and vegetation to prevent erosion and facilitate the successful reestablishment of vegetation covers, which would, over time, revert to pre-existing vegetation patterns and species.

6.9.3 Visual Impacts Associated with the Different Phases of Horizontal Drilling and Hydraulic Fracturing

Impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result at or in the vicinity of individual well locations. The following five general categories of visual impacts result from horizontal drilling and high-volume hydraulic-fracturing activities:

- construction-related impacts associated with the preparation of drill sites, including the construction of access roads, connecting pipelines, and other ancillary facilities; work during this phase progresses in a linear fashion, with impacts at any one location occurring for up to several weeks;

- development-related impacts associated with the drilling of wells, including the presence of drill rigs and equipment during the drilling phase; work during this phase progresses over an approximately 2- to 3-week period;

- development-related impacts associated with the fracturing of wells, including the presence of storage tanks, compressors, trucks, and other equipment that supports fracturing activities; work during this phase progresses over an approximately 2- to 3-week period;

- operational impacts associated with active well sites, which include the presence of production equipment if the well site is viable; this low-impact phase involves small pieces of equipment and pipeline connections for up to 30 years; and

- reclamation impacts associated with the removal of production equipment and the restoration of well site locations when operations are complete.

6.9.3.1 Visual Impacts Associated with Construction of Well Pads

Construction-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result from clearing and site preparation activities associated with access roads, well pads, connecting gas pipelines, retaining structures, and other support facilities such as water impoundments and water procurement sites. They would also include the impacts of site-specific construction-related traffic on both new and existing road systems. The end product of construction-related activities would be the creation of well sites and support facilities that are new landscape features within the surrounding existing setting, which may be incompatible with existing visual settings and land uses.

These construction-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual setting of areas in the vicinity of a well location, including views that contain a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of months while construction is underway), and may generally be perceived as negative throughout their duration. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.2 Visual Impacts Associated with Drilling Activities on Well Pads

Development-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result from the introduction of new and visible landscape features and activities into the existing settings that surround well locations. During drilling activities, such landscape features would include the newly created well pad sites, including associated access roads, pipeline rights-of-way, and other aboveground site facilities or structures such as water impoundment areas; the tall drill rigs; and on-site equipment to support drilling activities, such as on-site tanks for holding water, fuel, and drilling mud; generators; compressors; solids control equipment; a choke manifold; an accumulator; pipe racks; and the crew's office space.

Drilling rigs, which can reach heights of 150 feet or more, would be the most visible sign of drilling activity and when viewed from relatively short distances, such as from 1,000 feet to 0.5 miles, are relatively prominent landscape features. Because drilling may operate 24 hours a day, additional nighttime visual impacts may occur from rig lighting and open flaring (Rumbach 2011, Upadhyay and Bu 2010). Additional new and visible landscape features would include traffic related to the drilling of wells, including worker vehicles and heavy equipment used to drill wells at each well site.

Drilling-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual settings of areas surrounding a well location, including views that include a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of weeks while drilling is underway), and would generally be perceived as negative throughout their duration, primarily because of the high visibility of drilling activities from surrounding vantage points. While drilling activities are generally considered temporary or of short-duration, they may occur a number of times at well locations over a three-year period following the date that the initial drilling on a well site commences. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.3 Visual Impacts Associated with Hydraulic Fracturing Activities at Well Sites

Fracturing-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result from the introduction of new and visible landscape features and activities into the existing settings that surround well locations. During fracturing activities, such landscape features would include the newly created well pad sites, including: associated access roads, pipeline rights-of-way, and other aboveground site facilities or structures such as water impoundment areas; on-site equipment such storage vessels, trucks, and other equipment within containment areas; and buildings or other aboveground structures. On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features. Additional new and visible landscape features would include traffic related to the development of wells, including worker vehicles and heavy equipment used at each well site.

Fracturing-related visual impacts may be direct (i.e., impact the existing visual setting of a well location) or indirect (i.e., impact the existing visual settings of areas surrounding a well location, including views that include a well location). These visual impacts would be temporary or of short-term duration (i.e., a matter of weeks while hydraulic fracturing is underway) and would generally be perceived as negative throughout their duration, primarily because of the high visibility of fracturing activities from surrounding vantage points. While fracturing activities are generally considered temporary and of short duration, they would occur a number of times during the three-year period during which all wells at a well location would have to be drilled and fractured, and then episodically at well locations over the lifetime of the well, if hydraulic fracturing activities are repeated at wells to keep them viable (in production). These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.4 Visual Impacts Associated with Production at Well Sites

Operations-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result from extraction activities at viable well sites. The visual impacts of production would be less intrusive in surrounding landscapes, primarily because minimal on-site equipment is necessary during productions. Well site locations would consist of large, level grassy or graveled areas, with wellhead locations and small aboveground facilities for extraction and transfer of product into gas lines. Thousands of similar wellhead installations are already present in the area underlain by the Marcellus and Utica Shales in New York and may be considered relatively unobtrusive landscape features (see Photo 6.11 through Photo 6.20 at the end of Chapter 6). Although there would be some traffic associated with operations, including worker vehicles and equipment needed for operation and maintenance activities, the presence of such traffic would be substantially less than the traffic generated during construction and development (drilling and fracturing) of the wells.

Production-related visual impacts would be direct (i.e., directly impact the existing visual setting of a well location) and indirect (i.e., indirectly impact the existing settings within viewsheds that would contain a well location, including views of and from visual resources or visually sensitive areas that would also contain a well location) and would be of long-term duration (i.e., a number of years while active well sites remain viable). Operations-related visual impacts may initially be considered as having the potential for high visibility from surrounding vantage points, particularly when well locations are developed. However, over the lifetime of wells at a well location, which could be as long as 30 years from the commencement of drilling, operation-related activities at viable well pad locations would become integral features within their surrounding landscapes. These impacts on visual resources or visually sensitive areas would be both site-specific (i.e., within views that contain individual well locations) and cumulative (i.e., within views of areas or regions that contain concentrations of well locations).

6.9.3.5 Visual Impacts Associated with the Reclamation of Well Sites

Reclamation-related impacts on visual resources or visually sensitive areas such as those identified in Section 2.3.12 would result from the removal of on-site well equipment and structures and from site restoration activities. Site restoration activities would include recontouring the terrain at well sites to reestablish pre-existing topographic conditions and planting appropriate vegetative cover to reestablish appropriate site-specific vegetation species and growth patterns. Subsequent periodic reclamation-related visual impacts may also result from post-restoration inspection or monitoring and measures needed to ensure the successful reestablishment and succession of vegetation.

Reclamation-related visual impacts would be direct (i.e., directly impact the existing visual setting of a well location) and indirect (i.e., indirectly impact the existing settings within viewsheds that would contain a well location, including views of and from visual resources or visually sensitive areas that would also contain a well location). The duration of these temporary impacts would range from short term to long term. For example, removing well equipment and structures, recontouring the terrain, and replanting appropriate vegetation to reestablish pre-existing conditions would be of short-term duration (a matter of weeks or months). However, reclamation of forested areas may be of long-term duration.

Additional post-reclamation restoration activities may be necessary to ensure successful reestablishment of vegetation, consisting of periodic inspection or monitoring and implementation of any corrective actions to facilitate successful revegetation (such as corrective erosion control measures or vegetative replanting efforts). These activities would be episodic and may range from short-term to long term duration (from several months to as long as 1 to 3 years) to ensure successful revegetation. The potential impacts of short- to long-term inspection and monitoring activities on visual resources or visually sensitive areas during restoration are expected to be episodic and generally range from neutral to beneficial as vegetation succession proceeds.

All of the reclamation-related impacts on visual resources or visually sensitive areas would be both site specific (e.g., within views that contain individual well locations) and cumulative (e.g., within views of areas or regions containing concentrations of well locations).

6.9.4 Visual Impacts of Off-site Activities Associated with Horizontal Drilling and Hydraulic Fracturing

Section 6.9.3 discusses the nature of impacts on visual resources or visually sensitive areas that may be associated with on-site horizontal drilling and hydraulic-fracturing activities. However, off-site activities that could occur during one or more of the construction, development (drilling and fracturing), production, and reclamation phases also may result in additional indirect impacts on visual resources or visually sensitive areas, particularly during the periodic influx of specialized workforces during various phases of development. Such off-site activities may include changes in traffic volumes and patterns, depending on the phase of development occurring at one or more well sites in an area; and the development and/or use of existing or new contractor yards or equipment storage areas or other staging areas that may be necessary at various times (Upadhyay and Bu 2010).

The periodic and temporary influx of specialized workforces at various phases of development may also result in increased use of recreational vehicle or other camping areas (areas with cabins or designated for tent camping) for temporary or seasonal housing. While such camping areas may experience a congested appearance during such an influx, these areas are specifically designed for recreational vehicle or other camping activities, and the use of such areas in accordance with facility-specific occupancy rates may not be considered a negative impact on visual resources or visually sensitive areas.

The appearance and movement of specialized and large equipment and vehicles would result in temporary increases in traffic volumes and changes to traffic patterns, which would occur at various times during the construction, development (drilling and fracturing), and reclamation phases. This additional specialized traffic would occur on existing interstates, highways, and secondary roads and could result in increased congestion at intersections and bottlenecks (e.g., curves or bridges) or during particular hours (such as in the mornings and afternoons during the school year). This traffic would generally result in the increased visibility of construction- or production-related vehicles in the surrounding landscape. The new or increased presence of such specialized traffic may be considered a negative impact, particularly on highways and secondary roads that typically do not experience such construction-related traffic.

Additional cumulative visual impacts from traffic during the construction and development (drilling and fracturing) phase may occur where a number of wells are developed near each other at the same time, resulting in increased amounts of traffic. For areas with multiple well sites, this potential increase in traffic during the construction and development (drilling and fracturing) phase could increase the extent and duration of cumulative visual impacts. This potential cumulative visual impact from traffic used to construct and develop multiple well sites in an area might be reduced if the same operator develops multiple pads, because the same equipment may be used in phases to reduce the overall need and cost for the movement of equipment and materials.

The development of new and/or use of existing contractor yards or equipment storage areas or other staging areas may be necessary at various times during the construction, development (drilling and fracturing), and reclamation phases. Such areas may have a congested appearance during their use. If existing, previously developed contractor/storage yards or staging areas are used for such activities, their temporary and periodic use would be consistent with their existing setting and would have no new impact on visual resources or visually sensitive areas. However, if new yards or staging areas have to be created, the temporary and periodic use of such areas may represent a new impact on visual resources or visually sensitive areas.

6.9.5 Previous Evaluations of Visual Impacts from Horizontal Drilling and Hydraulic Fracturing

In 2010, students associated with the Department of City and Regional Planning at Cornell University, in Ithaca, New York, conducted a visual impact assessment of the hydraulic drilling process currently utilized in the Marcellus Shale region in Pennsylvania (specifically in Bradford County) (Upadhyay and Bu 2010). The purpose of this visual impact assessment was to describe the various activities and landscape features associated with horizontal drilling and hydraulic fracturing at individual well sites and across regions, and to examine the impacts or prominence of new landscape features at well sites in views from surrounding areas at specific distances and/or during different times of the day and year.[403]

The study also included evaluations of the potential for impacts on visual resources or visually sensitive areas at three existing well sites in Bradford County, Pennsylvania, using criteria presented in the New York State Environmental Quality Review (SEQR) Visual EAF Addendum. The evaluations were conducted to determine the way visual impacts from such sites would be considered in accordance with New York State guidelines for assessing visual impacts under the SEQR process. In addition, the visual impact study included predictive modeling for the appearance of one or more new well sites within views from State Route 13

[403] The visual impact assessment considered the visual impacts of only two well sites. Visual impact analysis was conducted primarily during the day; while some photodocumentation of the appearance of well sites was included in the visual impact assessment, the distances of nighttime views of the well sites were not specified. The assessment did not conduct analyses for the well sites during all phases of development (i.e., construction, development, production, and reclamation). The assessment also did not conduct similar analyses for off-site activities that might result in visual impacts (i.e., at areas used for temporary worker housing, areas experiencing high levels of construction or production-related traffic, or at contractor/storage yards or staging areas).

near Cayuga Heights and from Cornell University's Libe Slope, which are considered locally significant visually sensitive areas by the City of Ithaca, and recommended potential mitigation measures to minimize or mitigate negative impacts on visual resources or visually sensitive areas.

In the 2010 visual impact assessment, the descriptions and photographs of the various phases of horizontal drilling and hydraulic-fracturing activities that resulted in new landscape features in Bradford County, Pennsylvania, are generally consistent with the descriptions and photographs of the same processes presented in Section 6.9.2 and appear to correspond to the same phases of well development (construction, well development (drilling and fracturing), production, and reclamation) that are discussed above in Section 6.9.3.

Upadhyay and Bu's evaluation of existing visual impacts consisted of examining the daytime visibility of two different well locations in Bradford County, Pennsylvania, from various distances ranging from 1,000 feet to 3.5 miles from the sites.[404] The results of this study cannot be considered definitive because the visibility of only two well sites was examined and the examination was conducted primarily during daylight hours. However, the visibility of the two well sites appeared to be relatively limited at distances ranging from 0.5 to 3.5 miles away (Upadhyay and Bu 2010). The relatively restricted daytime visibility appears to be the result of perspective (i.e., landscape features associated with well sites do not appear as prominent features within the landscape at distances of a mile or more) and/or effective screening by sloping terrain and vegetative cover.

The 2010 visual impact assessment also included four nighttime photographs of well sites in Bradford County, Pennsylvania. Lighting for nighttime on-site operations or production

[404] Regions within the area underlain by the Marcellus and Utica Shales in New York have settings similar to that of Bradford County, Pennsylvania; thus, similar visual impacts from well sites may be expected. However, a number of different, if not unique, geographic conditions or settings are present in the Marcellus and Utica Shale area in New York, including: a large number of lakes and rivers and other natural areas used for recreational purposes and possessing scenic qualities; a number of regions that are primarily rolling agricultural land rather than sloping forestland (resulting in potentially increased visibility of landscape features from greater distances); and a number of cities connected by interstate and state highways (resulting in the potential for an increase in the number of views of and from visual resources or visually sensitive areas that would contain well sites, and in the potential for an increase in size of the viewing public). These different or unique geographic conditions and settings contain associated visual resources and visually sensitive areas, including those described above in Section 2.4, that may be affected by new landscape features associated with well sites (including off-site areas and activities) and that would be noticeable to the viewing public.

activities and lighting on equipment are visible in these views; a nighttime view of flaring from at least one well site is also presented in the visual impact assessment (Upadhyay and Bu 2010). Similar documentation of the nighttime appearance of well sites during the drilling phase was also provided in the Southern Tier Central Regional Planning and Development Boards (STC) approved Marcellus Tourism Study (Rumbach 2011).

While these photographs present the potential impacts of horizontal drilling and hydraulic-fracturing activities on visual resources and visually sensitive areas at night, a number of factors should be reflected in the analysis of nighttime impacts on visual resources or visually sensitive areas. First, the nighttime impacts of lighting or flaring would be temporary and limited primarily to the well development phase of horizontal drilling and hydraulic fracturing. Flaring would only occur during initial flowback at some wells, and the potential for flaring would be limited to the extent practicable by permit conditions, such that the duration of nighttime impacts from flaring typically would not occur for longer than three days. Second, the aesthetic qualities of visual resources or visually sensitive areas are typically not accessible (i.e., visible) at night. Third, the majority of the viewing public would typically not be present at the locations of most types of visual resources or visually sensitive areas during nighttime hours, with the exception of campgrounds, lakes, rivers, or other potentially scenic areas where recreational activities may extend into evening and nighttime hours for part of the year, or with the exception of nighttime drivers, whose view of flaring would be transient. Therefore, it is likely that the temporary negative impacts of any nighttime lighting and flaring would be either visible to only a small segment of the viewing public, or visible by a larger segment of the viewing public but only on a seasonal short-term basis.

The 2010 visual impact assessment (Upadhyay and Bu 2010) also included an evaluation of three well sites in Bradford County, Pennsylvania, using the criteria listed in NYSDEC's Visual Environmental Assessment Form (NYSDEC 2011a). These three sites are in settings that are similar to areas within the area underlain by the Marcellus and Utica Shales in New York.

Two of the three well sites were in the production phase; the third site contained an active drill rig, suggesting that it was in the drilling phase. All of the sites were in rural areas where there were no visual resources or visually sensitive areas as described in Section 2.3.12. All of the sites were in close proximity to other similar well sites and were visible from local nearby roadways and from a distance of 0.5 to 3 miles away. At two sites, agricultural and forest vegetation would provide seasonal screening; the third site was on or near the top of a hill and was visible from a larger surrounding area, despite the presence of forest vegetation (Upadhyay and Bu 2010).

Although no conclusions about the significance of potential visual impacts were made based on the criteria listed in NYSDEC's Visual Environmental Assessment Form (NYSDEC 2011a), it is likely that none of these well sites would be considered to have any significant visual impacts, primarily because no visual resources or visually sensitive areas as described in Section 2.3.12 are present, and it is likely that no further assessment or mitigation of visual impacts as described in NYSDEC Program Policy DEP-00-2 would be recommended or determined to be necessary.

Upadhyay and Bu's visual impact assessment also conducted limited three-dimensional modeling to examine the potential visual impacts of well sites during the drilling phase, when drill rigs are on-site, in two landscapes in the Ithaca area in Tompkins County, New York. Tompkins County, including the Ithaca area, is within the area underlain by the Marcellus and Utica Shales in New York. The two landscapes used for modeling consisted of (1) a view facing west of slopes on the western side of Cayuga Lake, from southbound Route 13 near Cayuga Heights (Cayuga Heights is a neighboring town along Cayuga Lake, just north of Ithaca on Route 13); and (2) a view facing west of upland well sites on the western side of Cayuga Inlet from Libe Slope on the Cornell University campus in Ithaca. The vantage points of both photos are estimated to be approximately 2.5 miles from the modeled well site locations. None of the modeled well sites appear to be prominent new landscape features within these locally designated scenic views. These results support similar conclusions made above, which were based on the daytime photographs of the existing wells in Bradford County, Pennsylvania, from various vantage points along surrounding local roads, i.e., that the visibility of new landscape features associated with well sites tends to be minimal from distances beyond 1 mile.

The potential for visual impacts from other new landscape features associated with the horizontal drilling and hydraulic fracturing process, such as interconnections with natural gas pipelines, was also considered in the STC's Marcellus Tourism Study (Rumbach 2011). This study suggested that potential impacts from the creation of new pipeline-rights-of-way might result in changes in vegetation patterns, primarily through the creation of new and visible corridors, particularly where forest would be removed. In addition, the study considered the potential for cumulative visual impacts of multiple well sites and associated off-site facilities across a relatively large area such as the STC region (which is comprised of Steuben, Schuyler, and Chemung counties). The overall conclusion of the STC's Marcellus Tourism Study was that cumulative visual impacts of multiple well sites and their associated off-site facilities may result from the creation of an industrial landscape that is not compatible with the current scenic qualities that are recognized for the STC region (Rumbach 2011).

The evaluation of existing and potential visual impacts of multiple well sites and their associated offsite facilities by Upadhyay and Bu (2010) and Rumbach (2011) generated information and conclusions that were considered when developing the visual impacts presented in Section 6.9.3 for the different phases of well site development in the area underlain by the Marcellus and Utica Shales in New York.

6.9.6 Assessment of Visual Impacts using NYSDEC Policy and Guidance

An assessment of a project's potential for visual impacts is generally part of the SEQR process and is triggered for Type I or unlisted projects, particularly when a Full Environmental Assessment Form (EAF) is required (NYSDEC 2011b). An addendum to the Full EAF, the Visual EAF Form, evaluates the potential for visual impacts and is required for those projects that may have an effect on aesthetic resources (NYSDEC 2011c).

The Visual EAF Form provides additional information on a project's potential visual impacts and their magnitude, including: information on the visibility of the project from visual resources and visually sensitive areas such as those described in Section 2.3.12; whether the visibility of the project is seasonal and whether the public uses any of the identified visual resources or visually sensitive areas during seasons when the project may be visible; a description of the surrounding visual environment; whether there are any similar projects within a 3-mile radius; the annual number of viewers likely to observe the proposed project; and the situation or activity in which the viewers are engaged while viewing the proposed project (NYSDEC 2011a).

In the event that significant resources such as those described in Section 2.3.12 are present and have viewsheds that contain proposed well sites, a formal visual assessment consistent with the procedures outlined in NYSDEC DEP-00-2 would be conducted. This formal visual assessment would consist of developing, "at a minimum, a line-of-sight profile, or depending upon the scope and potential significance of the activity, a digital viewshed" (such as computer-generated models or visual simulations) to determine whether a significant visual resource or visually sensitive area is within potential viewsheds of the proposed project (NYSDEC 2000).

Procedures for formal visual assessments would use control points established by NYSDEC staff and would include a worst-case scenario. A worst-case scenario for visual assessments is established using control points that reveal any project visibility at a visually significant resource. Generally, control points for the worst-case scenario are located in an attempt to reveal the tallest facility or project component. In addition, the impact area that would be evaluated in the formal visual assessment would be determined by NYSDEC staff and may be as large as a 5-mile-radius area around a project's various components (NYSDEC 2000).

NYSDEC staff would verify the potential significance of impacts on visual resources or visually sensitive areas using the qualities of the specific resource(s) and the juxtaposition of the project's components (using viewshed and/or line-of-sight profiles) as the guide for determining significance. If determined significant, visual impacts may require mitigation in accordance with NYSDEC DEP-000-2 guidelines (NYSDEC 2000). Procedures for mitigation are discussed in greater detail in Section 7.9.

6.9.7 Summary of Visual Impacts

The potential impacts of well development on visual resource and visually sensitive areas such as those identified in Section 2.3.12 are summarized below in Table 6.53.These potential impacts may result from on-site activities associated with construction, drilling, fracturing, production and reclamation; off-site activities associated with increased traffic; and the use of off-site areas for construction, staging, and housing. Given the generic nature of this analysis and the lack of specific well pad locations to evaluate for potential visual impacts, the impacts presented in this section are not resource-specific. Generic mitigation measures for these potential generic impacts are presented in Section 7.9.

Table 6.53 - Summary of Generic Visual Impacts Resulting from Horizontal Drilling and Hydraulic Fracturing in the Marcellus and Utica Shale Area of New York (New August 2011)

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Pad Construction	• Newly created well pads - open, level areas averaging approximately 3.5 acres in size • Newly created linear features such as access roads and connecting pipelines • Newly created water impoundment areas (if necessary) • Construction equipment, including bulldozers, graders, backhoes, and other large equipment for clearing, cutting, filling and grading activities • Trucks for hauling equipment and materials • Worker vehicles	• Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing visual setting of areas in the vicinity of a well location, including views that contain a well location • Temporary or short-term duration - during the weeks or months while construction is underway • Negative - because of the introduction of new features into the landscape • Site-specific - within views that contain individual well locations • Cumulative - within views of areas or regions that contain concentrations of well locations
On-site Well Drilling	• Drill rigs of varying heights and dimensions • Auxiliary on-site equipment such as storage tanks for water, fuel, and drilling mud; generators; compressors; solids control equipment; a choke manifold; an accumulator; pipe racks; and the crew's office space • Trucks for hauling equipment and materials • Worker vehicles	• Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing visual settings of areas surrounding a well location, including views that include a well location • Temporary - during the weeks while drilling is underway • Periodic - during the times when drilling may occur over a three-year period following the date that the initial drilling on a well site commences • Negative - throughout the duration of drilling, primarily because of the high visibility of drilling activities from surrounding vantage points • Site-specific - within views that contain individual well locations • Cumulative – within views of areas or regions that contain concentrations of well locations

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Fracturing	• On-site equipment such as storage tanks for water, fuel, and fracturing additives; compressors; cranes; pipe racks; and the crew's office space • Trucks, including tractor trailers and other large trucks for hauling sand and fracturing additives, pipe-hauling trucks, welding and other mechanical support trucks • Worker vehicles	• Direct impacts – on the existing visual setting of a well location • Indirect impacts - on the existing visual settings of areas surrounding a well location, including views that include a well location • Temporary or short-term duration – during the weeks while hydraulic fracturing is underway • Periodic - during the times when fracturing may occur over the lifetime of the well(s) • Negative - throughout their duration, primarily because of the high visibility of fracturing activities from surrounding vantage points. • Site-specific - within views that contain individual well locations • Cumulative – within views of areas or regions that contain concentration of well locations
Well Production	• Operating well pads - open, level areas averaging approximately 0.5 to 1.0 acre in size, maintained in grassy or graveled conditions • Wellhead locations and small aboveground facilities for the pumping and transfer of product into gas lines. • Access road maintained in graveled condition • Connecting pipeline right-of-way maintained with grassy vegetation	• Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that contain a well location • Long-term duration - during the years while active well sites remain viable • Negative - during short-term period of initial development • Neutral - during long-term period of production over a potential 30-year period • Site specific - within views that contain individual well locations • Cumulative – within views of areas or regions that contain concentrations of well locations

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
On-site Well Site Reclamation	• Initial bare areas resulting from the removal of wellheads and small aboveground facilities used during production; recontouring to pre-existing terrain conditions; and revegetation efforts • Subsequent vegetated areas reverting to pre-existing vegetation patterns and species	• Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that would contain a well location • Temporary to short term - during removal of well equipment and structures, recontouring terrain, and replanting of vegetation • Periodic and long-term - during periodic inspection or monitoring and implementation of any corrective actions to facilitate successful revegetation for several months to as long as one to three years • Neutral to beneficial - as vegetation succession proceeds • Site specific - within views that contain individual well locations • Cumulative – within views of areas or regions containing concentrations of well locations
Off-site changes in traffic volumes and patterns	• Increased traffic during the construction, drilling and fracturing, and reclamation phases of well development • Increased traffic would be local (at one or more well sites in close proximity) • Increased traffic may be regional (in areas where numerous multi-well sites are under development)	• Direct impacts - on the existing visual setting of a well location • Indirect impacts - on the existing settings within viewsheds that contain a well location • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Negative - due to the appearance and movement of high numbers of specialized and large equipment and vehicles • Site specific - at specific well locations • Cumulative – within views of areas or regions containing concentrations of well locations under development at the same time

Description of Activity	Description of Typical New Landscape Features	Description of Potential Visual Impacts
Off-site periodic and temporary influx of specialized workforces at various phases of development	• Increased use of local recreational vehicle or other camping areas (areas with cabins or designated for tent camping) for temporary or seasonal housing. • Increased local worker traffic during and after working hours	• Direct impacts - on the existing visual setting of off-site housing locations and on local roads • Indirect impacts - on the existing settings within viewsheds that would contain off-site housing and local roads • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Neutral to negative - occupancy of existing off-site housing locations would be consistent with capacity, but local traffic may result in congestion during and after work hours • Site-specific – at specific housing locations and along local roads
Off-site contractor yards or equipment storage areas or other staging areas	• Increased traffic and activity associated with construction and use of new contractor yards, equipment storage areas or other staging areas • Increased traffic and activity associated with use of existing contractor yards, equipment storage areas, or other staging areas	• Direct impacts - on the existing visual setting of an off-site yard, storage area, or staging area • Indirect impacts - on the existing settings within viewsheds that contain an off-site yard, storage area, or staging area • Temporary and periodic - during specific phases of well development (construction, drilling, fracturing, and reclamation) • Negative - due to the appearance and movement of high numbers of specialized and large equipment and vehicles • Site specific – at specific off-site yard, storage area, or staging area locations

6.10 Noise [405]

The noise impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. The rigs and supporting equipment are somewhat larger than the commonly used equipment described in 1992, but with the exception of specialized downhole tools, horizontal drilling is performed using the same equipment, technology, and procedures as used for many wells that have been drilled in New York. Production-phase well site equipment is very quiet and has negligible impacts.

The greatest difference with respect to noise impacts, however, is in the duration of drilling. A horizontal well takes four to five weeks of drilling at 24 hours per day 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 pounds per square inch (psi). High-volume hydraulic fracturing of a typical horizontal well could require, on average, 3.6 million gallons of water and a maximum pumping pressure that may be as high as 10,000 to 11,000 psi. This volume and pressure would 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 would also be significantly more trucking and associated noise involved with high-volume hydraulic fracturing than was addressed in the 1992 GEIS.

Site preparation, drilling, and hydraulic fracturing activities could result in temporary noise impacts, depending on the distance from the site to the nearest noise-sensitive receptors.

Typically, the following factors are considered when evaluating a construction noise impact:

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[405] Section 6.10, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Difference between existing noise levels prior to construction startup and expected noise levels during construction;
- Absolute level of expected construction noise;
- Adjacent land uses; and
- The duration of construction activity.

In order to evaluate the potential noise impacts related to the drilling operation phases, a construction noise model was used to estimate noise levels at various distances from the construction site during a typical hour for each phase of construction. The algorithm in the model considered construction equipment noise specification data, usage factors, and distance. The following logarithmic equation was used to compute projected noise levels:

$$Lp1 = Lp2 + 10\log(U.F./10) – 20\log(d2/d1):$$

where:

Lp1	=	the average noise level (dBA) at a distance (d2) due to the operation of a unit of equipment throughout the day;
Lp2	=	the equipment noise level (dBA) at a reference distance (d1);
U.F.	=	a usage factor that accounts for a fraction of time an equipment unit is in use throughout the day;
d2	=	the distance from the unit of equipment in feet; and
d1	=	the distance at which equipment noise level data is known.

Noise levels and usage factor data for construction equipment were obtained from industry sources and government publications. Usage factors were used to account for the fact that construction equipment use is intermittent throughout the course of a normal workday.

Once the average noise level for the individual equipment unit was calculated, the contribution of all major noise-producing equipment on-site was combined to provide a composite noise level at various distances using the following formula:

$$Leq_{total} = 10\log\left(10^{\frac{Leq_1}{10}} + 10^{\frac{Leq_2}{10}} + 10^{\frac{Leq_3}{10}} ...etc.\right)$$

Using this approach, the estimated noise levels are conservative in that they do not take into consideration any noise reduction due to ground attenuation, atmospheric absorption, topography, or vegetation.

6.10.1 Access Road Construction

Newly constructed access roads are typically unpaved and are generally 20 to 40 feet wide during the construction phase and 10 to 20 feet wide during the production phase. They are constructed to efficiently provide access to the well pad while minimizing potential environmental impacts.

The estimated sound pressure levels (SPLs) produced by construction equipment that would be used to build or improve access roads are presented in Table 6.54 for various distances. The composite result is derived by assuming that all of the construction equipment listed in the table is operating at the percent utilization time listed and by combining their SPLs logarithmically.

These SPLs might temporarily occur over the course of access road construction. Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.

Table 6.54 - Estimated Construction Noise Levels at Various Distances for Access Road Construction (New August 2011)

Construction Equipment	Quantity	Usage Factor %	Lmax SPL @ 50 Feet (dBA)	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Excavator	2	40	81	80	66	60	54	50	48
Grader	2	40	85	84	70	64	58	54	52
Bulldozer	2	40	82	81	67	61	55	51	49
Compactor	2	20	83	79	65	59	53	49	47
Water truck	2	40	76	75	61	55	49	45	43
Dump truck	8	40	76	81	67	61	55	52	49
Loader	2	40	79	78	64	58	52	48	46
Composite Noise Level				**89**	**75**	**69**	**63**	**59**	**57**

Source: FHWA 2006.

Key:

adj = adjusted.

dBA = A-weighted decibels.

L_{max} = maximum noise level.

SPL = Sound Pressure Level.

6.10.2 Well Site Preparation

Prior to the installation of a well, the site must be cleared and graded to make room for the placement of the necessary equipment and materials to be used in drilling and developing the well. The site preparation would generate noise that is associated with a construction site, including noise from bulldozers, backhoes, and other types of construction equipment. The A-weighted SPLs for the construction equipment that typically would be utilized during well pad preparation are presented in Table 6.55 along with the estimated SPLs at various distances from the site. Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.

Table 6.55 - Estimated Construction Noise Levels at Various Distances for Well Pad Preparation (New August 2011)

Construction Equipment	Quantity	Usage Factor %	Lmax SPL @ 50 Feet (dBA)	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Excavator	1	40	81	77	63	57	51	47	45
Bulldozer	1	40	82	78	64	58	52	48	46
Water truck	1	40	76	72	58	52	46	42	40
Dump truck	2	40	76	75	61	55	49	45	43
Pickup truck	2	40	75	74	60	54	48	44	42
Chain saw	2	20	84	80	66	60	54	50	48
	Composite Noise Level			**84**	**70**	**64**	**58**	**55**	**52**

Source: FHWA 2006.

Key:

adj = adjusted.

dBA = A-weighted decibels.

L_{max} = maximum noise level.

SPL = Sound Pressure Level.

6.10.3 High-Volume Hydraulic Fracturing – Drilling

High-volume hydraulic fracturing involves various sources of noise. The primary sources of noise were determined to be as follows:

- Drill Rigs. Drill rigs are typically powered by diesel engines, which generate noise emissions primarily from the air intake, crankcase, and exhaust. These levels fluctuate depending on the engine speed and load.

- Air Compressors. Air compressors are typically powered by diesel engines and generate the highest level of noise over the course of drilling operations. Air compressors would be in operation virtually throughout the drilling of a well, but the actual number of operating compressors would vary. However, more compressed air capacity is required as the drilling advances.

- 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.

- 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 operator 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.

- Drill Pipe Connections. As the depth of the well increases, the operator 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 higher frequency noise impact.

Once initiated, the drilling operation often continues 24 hours a day until completion and would therefore generate noise during nighttime hours, when people are generally involved in activities that require lower ambient noise levels. Certain noise-producing equipment is typically operated on a fairly continuous basis during the drilling process. The types and quantities of this equipment are presented in Table 6.56 for rotary air drilling and in Table 6.57 for horizontal drilling (see Photo 6.6), along with the estimated A-weighted individual and composite SPLs that would be experienced at various distances from the operation. An analysis of both types of drilling is included since according to industry sources, in accessing the natural gas formation, rotary air drilling is often used for the vertical section of the well and then horizontal drilling is used for making the turn and completing the horizontal section.

Table 6.56 - Estimated Construction Noise Levels at Various Distances for Rotary Air Well Drilling (New August 2011)

Construction Equipment	Quantity	Sound Power Level (dBA)	Distance in Feet/SPL[1] (dBA)					
			50 (adj.)	250	500	1,000	1,500	2,000
Drill rig drive engine	1	105	71	57	51	45	41	38
Compressors	4	105	77	63	57	51	47	45
Hurricane booster	3	81	51	37	31	25	22	19
Compressor exhaust	1	85	51	37	31	25	21	18
Composite Noise Level			**79**	**64**	**58**	**52**	**48**	**45**

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Key:

adj = adjusted to quantity.

Table 6.57 - Estimated Construction Noise Levels at Various Distances for Horizontal Drilling (New August 2011)

Construction Equipment	Quantity	Sound Level	Distance	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1000	1500	2000
Rig drive motor	1	105[2]	0	71	57	51	45	41	38
Generator	3	81[2]	0	51	37	31	25	22	19
Top drive	1	85[1]	5	65	51	45	39	35	33
Draw works	1	74[1]	10	60	46	40	34	30	28
Triple shaker	1	85[1]	15	75	61	55	49	45	43
Composite Noise Level				**76**	**62**	**56**	**50**	**47**	**44**

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Key:

adj = adjusted to quantity.

Photo 6.6 - Electric Generators, Active Drilling Site (New August 2011)

Intermittent operations that occur during drilling include tubular preparation and cleaning, elevator operation, and drill pipe connection blowdown. These shorter-duration events may occur at intervals as short as every 20 to 30 minutes during drilling. Noise associated with the drilling activities would be temporary and would end once drilling operations cease.[406]

6.10.4 High-Volume Hydraulic Fracturing – Fracturing

During the hydraulic fracturing process, water, sand, and other additives are pumped under high pressure into the formation to create fractures. To inject the required water volume and achieve the necessary pressure, up to 20 diesel-pumper trucks operating simultaneously are necessary (see Photo 6.7 and Photo 6.8). Typically the operation takes place over two to five days for a single well. Normally, hydraulic fracturing is only performed once in the life of a well. The sound level measured for a diesel- pumper truck under load ranges from 110 to 115 dBA at a distance of 3 feet. Noise from the diesel engine varies according to load and speed, but the main component of the sound spectrum is the fundamental engine rotation speed. The diesel engine

[406] Page 4, - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002)

sound spectrum, which peaks in the range of 50 Hz to 250 Hz, contains higher emissions in the lower frequencies.

Table 6.58 presents the estimated noise levels that may be experienced at various distances from a hydraulic fracturing operation, based on 20 pumper trucks operating at a sound power level of 110 dBA and 20 pumper trucks operating at a sound power level of 115 dBA.

Table 6.58 - Estimated Construction Noise Levels at Various Distances for High-Volume Hydraulic Fracturing (New August 2011)

Construction Equipment	Quantity	SPL[1] (dBA)	Distance (feet)	Quantity Adjusted Sound Level	Distance in Feet/SPL[1] (dBA)					
					50	250	500	1000	1500	2000
Pumper truck	20	110	3	123	99	85	79	73	69	67
Pumper truck	20	115	3	128	104	90	84	78	74	72

Source: Confidential Industry Source.

[1] SPL = Sound Pressure Level

Photo 6.7 - Truck-mounted Hydraulic Fracturing Pump (New August 2011)

Photo 6.8 - Hydraulic Fracturing of a Marcellus Shale Well Site (New August 2011)

The existing sound level in a quiet rural area at night may be as low as 30 dBA at times. Since the drilling and hydraulic fracturing operations are often conducted on a 24-hour basis, these operations, without additional noise mitigations, may result in an increase in noise of 37 to 42 dB over the quietest background at a distance of 2,000 feet. As indicated previously, according to NYSDEC guidance, sound pressure increases of more than 6 dB may require a closer analysis of impact potential, depending on existing SPLs and the character of surrounding land use and receptors, and an increase of 6 dB(A) may cause complaints. Therefore, mitigation measures would be required if increases of this nature would be experienced at a receptor location.

Table 6.59 presents the estimated duration of the various phases of activity involved in the completion of a typical installation. Multiple well pad installations would increase the drilling and hydraulic fracturing duration in a given area.

Table 6.59 - Assumed Construction and Development Times (New August 2011)

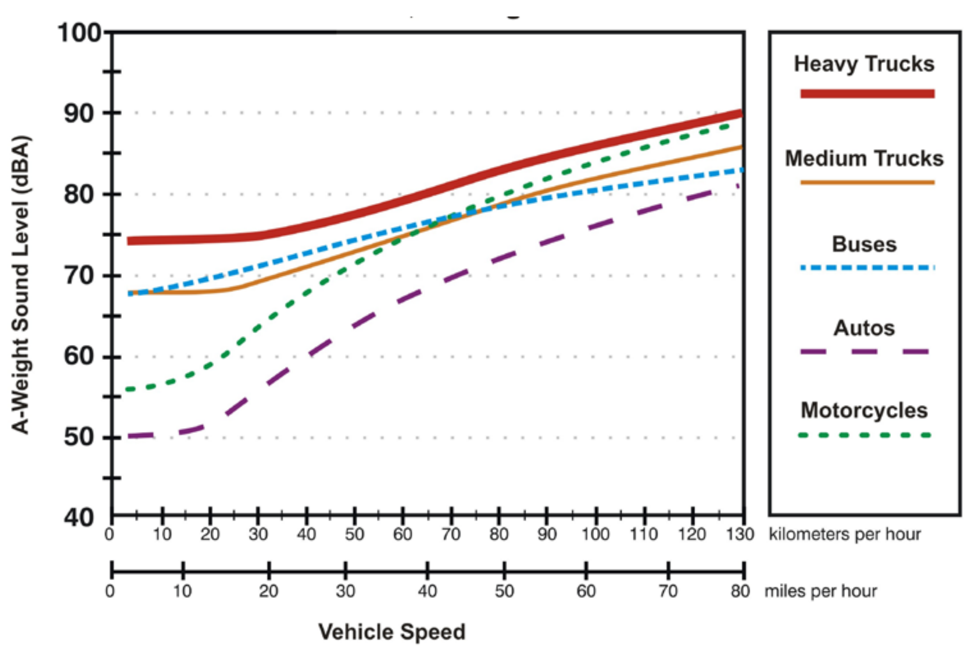
Operation	Estimated Duration (days)
Access roads	3 - 7
Site preparation/well pad	7 - 14
Well drilling	28 - 35
Hydraulic fracturing single well	2 - 5

6.10.5 Transportation

Similar to any construction operation, drill sites require the use of support equipment and vehicles. Specialized cement equipment and vehicles, water trucks, flatbed tractor trailers, and delivery and employee vehicles are the most common forms of support machinery and vehicles. Cement equipment would generate additional noise during operations, but this impact is typically short lived and is at levels below that of the compressors described above.

The noise levels generated by vehicles depend on a number of variable conditions, including vehicle type, load and speed, nature of the roadway surface, road grade, distance from the road to the receptor, topography, ground condition, and atmospheric conditions. Figure 6.21 depicts measured noise emission levels for various vehicles and cruise speeds at a distance of 50 feet on average pavement. As shown in the figure, a heavy truck passing by at 50 miles per hour would contribute a noise level of approximately 83 dBA at 50 feet from the road in comparison to a passing automobile, which would contribute approximately 73 dBA at 50 feet. Although a truck passing by would constitute a short duration noise event, multiple truck trips along a given road could result in higher hourly Leq noise levels and impacts on noise receptors close to main truck travel routes. The noise impact of truck traffic would be greater for travel along roads that do not normally have a large volume of traffic, especially truck traffic.

Figure 6.21 - A-Weighted Noise Emissions: Cruise Throttle, Average Pavement (New August 2011)



FHWA 1998.

In addition to the trucks required to deliver the drill rig and its associated equipment, trucks are used to bring in water for drilling and hydraulic fracturing, sand for hydraulic fracturing additive, and frac tanks. Trucks are also used for the removal of flowback for the site. Estimates of truck trips per well and truck trips over time during the early development phase of a horizontal and a vertical well installation are presented in Section 6.11, Transportation.

Development of multiple wells on a single pad would add substantial additional truck traffic volume in an area, which would be at least partially offset by a reduction in the number of well pads overall.

This level of truck traffic could have negative noise impacts on those living in proximity to the well site and access road. Like other noise associated with drilling, this would be 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 proximity to the pad would experience adverse noise impacts intermittently for up to three years.

6.10.6 Gas Well Production

Once the well has been completed and the equipment has been demobilized, the pad is partially reclaimed. The remaining wellhead production does not generate a significant level of noise.

Operation and maintenance activities could include a truck visit to empty the condensate collection tanks on an approximately weekly basis, but condensate production from the Marcellus Shale in New York is not typically expected. Mowing of the well pad area occurs approximately two times per year. These activities would result in infrequent, short-term noise events.

6.11 Transportation Impacts[407]

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 in the regions where natural gas development would occur. This section presents (1) industry

[407] Section 6.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

estimates on the number of heavy- and light-duty trucks needed for horizontal well drilling as compared to vertical drilling that already takes place, (2) comparisons and reasonable scenarios with which to gauge potential impacts on the existing road system and transportation network, (3) potential impacts on roadways and the transportation network, and (4) potential impacts on rail and air service.

6.11.1 Estimated Truck Traffic

The Department requested information from the Independent Oil & Gas Association of New York (IOGA-NY) to estimate the number of truck trips associated with well construction.

6.11.1.1 Total Number of Trucks per Well

Table 6.60 presents the total estimated number of one-way (i.e., loaded) truck trips per horizontal well during construction, and Table 6.61 presents the total estimated number of one-way truck trips per vertical well during construction. Information is further provided on the distribution of light- and heavy-duty trucks for each activity associated with well construction. Table 6.62 summarizes the total overall light- and heavy-duty truck trips per well for both vertical and horizontal wells. The Department assumed that all truck trips provided in the industry estimates were one-way trips; thus, to obtain the total vehicle trips, the numbers were doubled to obtain the round-trips across the road network (Dutton and Blankenship 2010).

As discussed in 1992 regarding conventional vertical wells, trucking during the long-term production life of a horizontally drilled single or multi-well pad would be insignificant.

IOGA-NY provided estimates of truck trips for two periods of development, as shown in Table 6.60 and Table 6.61: (1) a new well location completed early on in the development life of the field, and (2) a well location completed during the peak development year. During the early well pad development, all water is assumed to be transported to the site by truck. During the peak well pad development, a portion of the wells are assumed to be accessible by pipelines for transport of the water used in the hydraulic fracturing.

As shown in comparing the number of truck trips per well in Table 6.60 and Table 6.61, the truck traffic associated with drilling a horizontal well with high-volume hydraulic fracturing is 2 to 3 times higher than the truck traffic associated with drilling a vertical well.

Table 6.60 - Estimated Number of One-Way (Loaded) Trips Per Well:
Horizontal Well[1] (New August 2011)

Well Pad Activity	**Early Well Pad Development (all water transported by truck)**		**Peak Well Pad Development (pipelines may be used for some water transport)**	
	Heavy Truck	**Light Truck**	**Heavy Truck**	**Light Truck**
Drill pad construction	45	90	45	90
Rig mobilization[2]	95	140	95	140
Drilling fluids	45		45	
Non-rig drilling equipment	45		45	
Drilling (rig crew, etc.)	50	140	50	140
Completion chemicals	20	326	20	326
Completion equipment	5		5	
Hydraulic fracturing equipment (trucks and tanks)	175		175	
Hydraulic fracturing water hauling[3]	500		60	
Hydraulic fracturing sand	23		23	
Produced water disposal	100		17	
Final pad prep	45	50	45	50
Miscellaneous	-	85	-	85
Total One-Way, Loaded Trips Per Well	**1,148**	**831**	**625**	**795**

Source: All Consulting 2010.

1. Estimates are based on the assumption that a new well pad would be developed for each single horizontal well. However, industry expects to initially drill two wells on each well pad, which would reduce the number of truck trips. The well pad would, over time, be developed into a multi-well pad.
2. Each well would require two rigs, a vertical rig and a directional rig.
3. It was conservatively assumed that each well would use approximately 5 million gallons of water total and that all water would be trucked to the site. This is substantially greater than the likely volume of water that would be trucked to the site.

Table 6.61 - Estimated Number of One-Way (Loaded) Trips Per Well: Vertical Well (New August 2011)

Well Pad Activity	**Early Well Pad Development (all water transported by truck)**		**Peak Well Pad Development (pipelines may be used for some water transport)**	
	Heavy Truck	**Light Truck**	**Heavy Truck**	**Light Truck**
Drill pad construction	32	90	25	90
Rig mobilization	50	140	50	140
Drilling fluids	15		15	
Non-rig drilling equipment	10		10	
Drilling (rig crew, etc.)	30	70	30	70
Completion chemicals	10	72	10	72
Completion equipment	5		5	
Hydraulic fracturing equipment (trucks and tanks)	75		75	
Hydraulic fracturing water hauling	90		25	
Hydraulic fracturing sand	5		5	
Produced water disposal	42		26	
Final pad prep	34	50	34	50
Miscellaneous	0	85	0	85
Total One-Way, Loaded Trips Per Well	**398**	**507**	**310**	**507**

Source: All Consulting 2010.

Table 6.62 - Estimated Truck Volumes for Horizontal Wells Compared to Vertical Wells (New August 2011)

	Horizontal Well with High-Volume Hydraulic Fracturing		**Vertical Well**	
	Heavy Truck	**Light Truck**	**Heavy Truck**	**Light Truck**
Light-duty trips	831	795	507	507
Heavy-duty trips	1,148	625	389	310
Combined Total	**1,975**	**1,420**	**905**	**817**
Total Vehicle Trips	**3,950**	**2,840**	**1,810**	**1,634**

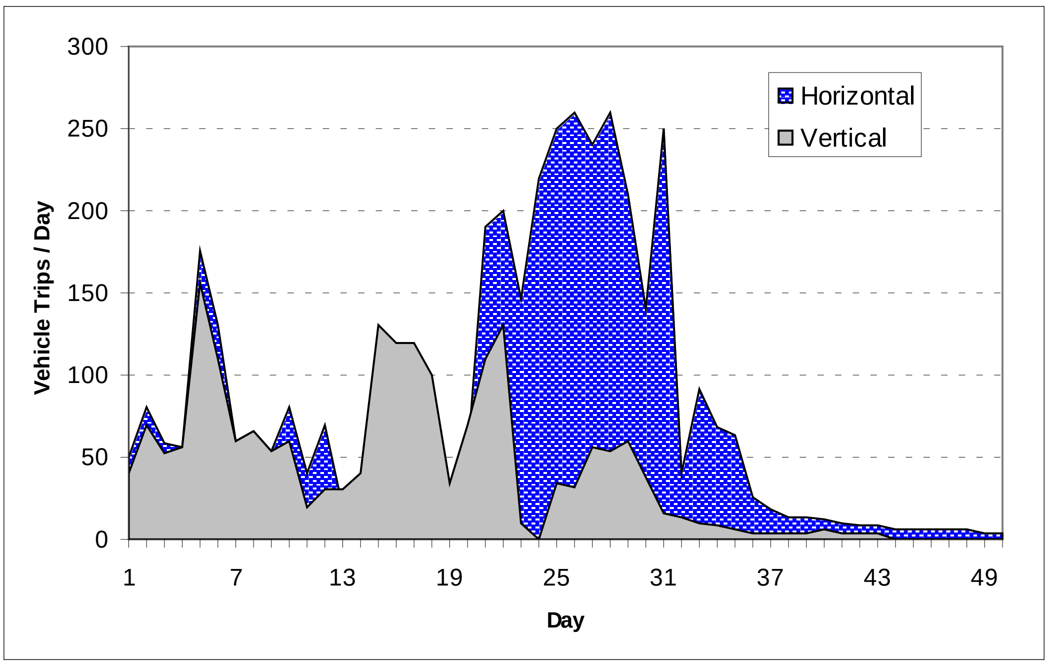
Source: Dutton and Blankenship 2010

Note: The first three rows in this table are round trips; total vehicle trips are one-way trips.

6.11.1.2 Temporal Distribution of Truck Traffic per Well

Figure 6.22 shows the daily distribution of the truck traffic over the 50-day period of early well pad development of a horizontal well and a vertical well (Dutton and Blankenship 2010). As seen in the figure, certain phases of well development require heavier truck traffic (peaks in the graph). Initial mobilization and drilling is comparable between horizontal and vertical wells; however, from Day 20 to Day 35, the horizontal well requires significantly more truck transport than the vertical well.

Figure 6.22 - Estimated Round-Trip Daily Heavy and Light Truck Traffic,
by Well Type - Single Well (New August 2011)



Source: Dutton and Blankenship 2010.

6.11.1.3 Temporal Distribution of Truck Traffic for Multi-Well Pads

The initial exploratory development using horizontal wells and high-volume hydraulic fracturing would likely involve a single well on a pad. However, commercial demand would likely expand development, resulting in multiple wells being drilled on a single pad, with each horizontal well extending into a different sector of shale. Thus, horizontal wells would be able to access a larger sector of the shale from a single pad site than would be possible for traditional development with vertical wells. This means there would be less truck traffic for the development of the pad itself.

There is a tradeoff, however, as each horizontal well utilizing the high-volume hydraulic fracturing method of extraction would require more truck trips per well than vertical wells (Dutton and Blankenship 2010).

Two development scenarios were proposed to estimate the truck traffic for horizontal and vertical well development for multi-well pads (Dutton and Blankenship 2010). The key parameters and assumptions are as follows:

Multi-pad Development Scenario 1: Horizontal Wells with High-Volume Hydraulic Fracturing:

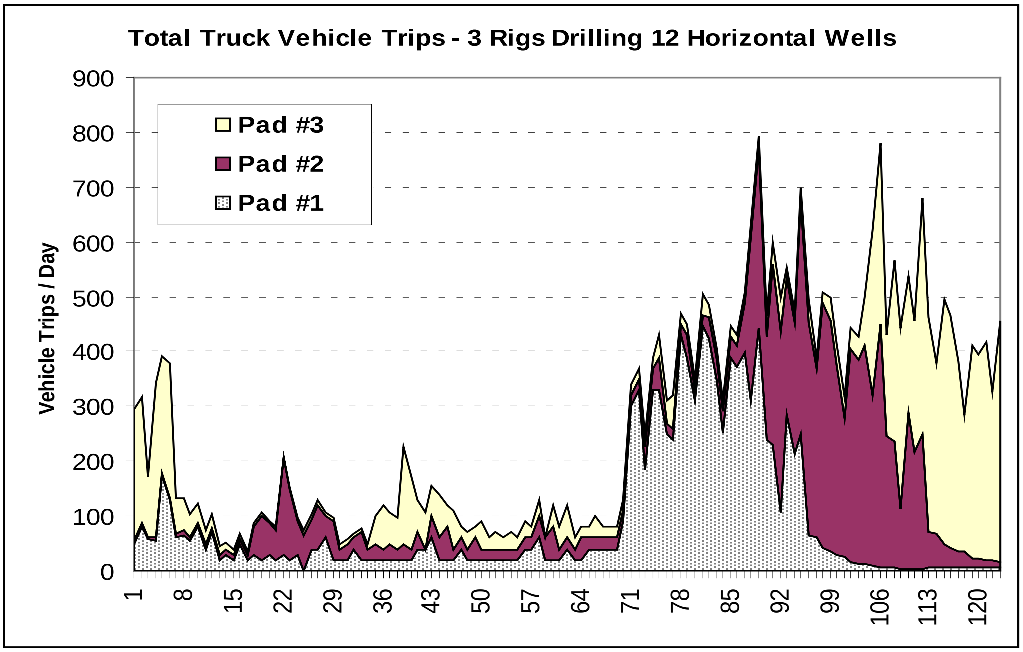
- Three rigs operated over a 120-day period.
- Each rig drills four wells in succession, then moves off to allow for completion.
- All water needed to complete the fracturing is hauled in via truck.
- Fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells.
- At an average of 160 acres per well, the three rigs develop a total of 1,920 acres of land.

Multi-pad Development Scenario 2: Vertical Wells

- Four rigs operated over a 120-day period
- Each rig drills four wells, moving to a new location after drilling of a well is completed.
- All water needed to complete the fracturing is hauled in via truck.
- Fracturing and completion of each well occurs after the rig relocates to a new location.
- At an average of 40 acres per well, the four rigs develop a total of 640 acres of land.

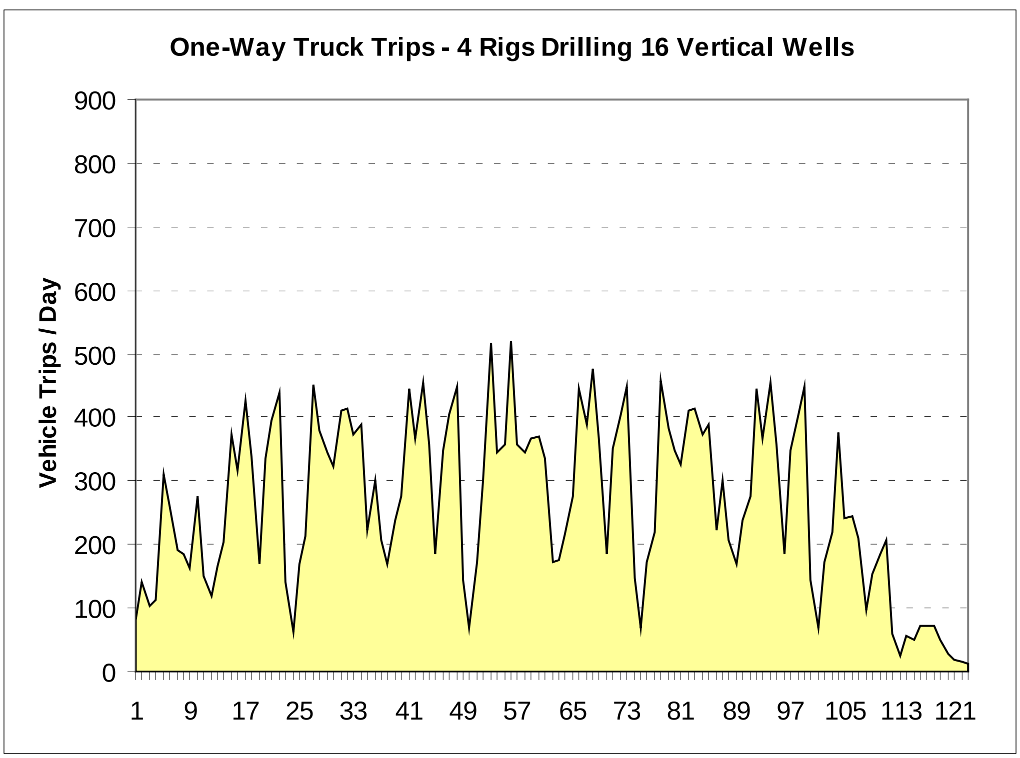
The extra yield of horizontal wells was compensated for by assuming that four vertical rigs were utilized during the same time span as three horizontal rigs. The results of these two development scenarios on a day-by-day basis are depicted in Figure 6.23 and Figure 6.24. As shown, the number of vehicle trips varies depending on the number of wells per pad. Horizontal wells have the highest volume of truck traffic in the last five weeks of well development, when fluid is utilized in high volumes. This is in contrast to the more conventional vertical wells (see Figure 6.24), where the volume of truck traffic is more consistent throughout the period of development.

Figure 6.23 - Estimated Daily Round-Trips of Heavy and Light Truck Traffic - Multi Horizontal Wells (New August 2011)



Source: Dutton and Blankenship 2010.

Figure 6.24 - Estimated Round-Trip Daily Heavy and Light Truck Traffic - Multi Vertical Wells (New August 2011)



Source: Dutton and Blankenship 2010.

The major conclusions to be drawn from this comparison of the truck traffic resulting from the use of horizontal and vertical wells are as follows (Dutton and Blankenship 2010):

- Peak-day traffic volumes given sequential completions with multiple rigs drilling horizontal wells along the same access road could be substantially higher than those for multiple rigs drilling vertical wells.

- The larger the area drained per horizontal well and the drilling of multiple wells from a pad without moving a rig offsets some of the increase in truck traffic associated with the high-volume fracturing.

- Based on industry data and other assumptions applied for these scenarios, the total number of vehicle trips generated by the three rigs drilling 12 horizontal wells is roughly equivalent to the number of vehicle trips associated with four rigs drilling 16 vertical wells. However, the horizontal wells require three-times the amount of land (1,920 acres for horizontal wells versus 640 acres for vertical wells). Thus, developing the same amount of land using vertical wells would either require three times longer, or would require deployment of 12 rigs during the same period, effectively tripling the total number of trips and result in peak daily traffic volumes above the levels associated with horizontal wells.

Based upon the information presented in these two development scenarios, utilizing horizontal wells and high-volume hydraulic fracturing rather than vertical wells to access a section of land would reduce the total amount of truck traffic. However, because vertical well hydraulic fracturing is not as efficient in its extraction of natural gas, it is not always economically feasible for operators to pursue. Currently, it is estimated that 10% of the wells drilled to develop low-permeability reservoirs with high-volume hydraulic fracturing will be vertical. Thus, the number of permits requested by applicants and issued by NYSDEC has not been fully reached. Horizontal drilling with high-volume hydraulic fracturing would be expected to result in a substantial increase in permits, well construction, and truck traffic over what is present in the current environment.

6.11.2 Increased Traffic on Roadways

As described in Section 6.8, Socioeconomics, three possible development scenarios are being assessed in this SGEIS to reflect the uncertainties associated with the future development of natural gas reserves in the Marcellus and Utica Shales – a high, medium and low development scenario. Each development scenario is defined by the number of vertical and horizontal wells drilled annually. (A summary of the development scenarios is provided in Section 6.8). Based on the number of wells estimated in each development scenario and the estimated number of truck trips per well as discussed above in Section 6.1.1, the total estimated truck trips for all wells developed annually is provided in Table 6.63. Annual trips are projected for Years 1 through 30 in 5-year increments. Estimated truck trips are provided for the three representative regions (Regions A, B, and C), New York State outside of the three regions, and statewide.

The proposed action would also have an impact on traffic on federal, state, county, regional local roadways. Given the generic nature of this analysis, and the lack of specific well pad locations to permit the identification of specific road-segment impacts, the projected increase in average annual daily traffic (AADT) and the associated impact on the level of service on specific roadway segments, interchanges, and intersections cannot be determined. The AADT on roadways can vary significantly, depending largely on functional class, and particularly whether the count was taken in heavily populated communities or in proximity to heavily traveled intersections/interchanges. Trucks traveling on higher level roadways along arterials and major collectors are not anticipated to have a significant impact on traffic patterns and traffic flow, as these roads are designed for a high level of vehicle traffic, and the anticipated increase in the level of traffic associated with this action would only represent a small, incremental change in existing conditions. However, certain local roads and minor collectors would likely experience congestion during certain times of the day or during certain periods of well development.

Table 6.64 illustrates this variation by providing the highest and lowest AADT on three functional class roads in three counties, one in each of the representative regions. The counts presented are the lowest and highest counts on the identified road in the designated functional class in the county.

On some roads, truck traffic generated by high-volume hydraulic fracturing operations may be small compared to total AADT, as would be the case on I-17 in Binghamton, where AADT was approximately 77,000 vehicles. In other cases, and particularly on collectors and minor arterials, traffic from high-volume hydraulic fracturing could be a large share of AADT. Truck traffic from high-volume hydraulic fracturing operations could also be a large share of total daily truck traffic on specific stretches of certain interstates and be much larger than existing truck volumes on lower functional class roads that serve natural gas wells or link the wells to major truck heads such as water supply, rail trans-loading, and staging areas.

Table 6.63 - Estimated Annual Heavy Truck Trips (in thousands) (New August 2011)

	Region A			**Region B**			**Region C**								
Counties	**Broome, Chemung, Tioga,**			**Delaware, Otsego, Sullivan**			**Cattaraugus, Chautauqua**			**Rest of New York State**			**State-Wide Totals**		
Low Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	4,334	226	4,561	2,053	113	2,166	456	0	456	1,597	113	1,710	8,441	453	8,893
5	21,216	1,245	22,460	9,809	566	10,375	2,053	113	2,166	9,353	453	9,806	42,431	2,376	44,807
10	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
15	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
20	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
25	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
30	42,431	2,376	44,807	19,391	1,132	20,522	4,334	226	4,561	18,478	1,018	19,496	84,634	4,752	89,387
Average Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	16,881	1,018	17,900	7,756	453	8,209	1,597	113	1,710	7,528	339	7,868	33,763	1,924	35,686
5	84,634	4,752	89,387	39,009	2,150	41,159	8,441	453	8,893	37,184	2,150	39,334	169,269	9,505	178,773
10	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
15	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
20	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
25	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
30	169,269	9,505	178,773	77,791	4,413	82,203	16,881	905	17,786	74,597	4,187	78,783	338,538	19,009	357,547
High Development Scenario															
Year	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**	**Horizontal**	**Vertical**	**Total**
1	25,322	1,471	26,793	11,634	679	12,313	2,509	113	2,623	11,178	566	11,744	50,644	2,829	53,473
5	126,381	7,015	133,397	58,172	3,168	61,340	12,547	679	13,226	55,663	3,055	58,718	252,763	13,917	266,680
10	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
15	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
20	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
25	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360
30	252,763	13,917	266,680	116,344	6,450	122,793	25,322	1,358	26,680	111,097	6,110	117,207	505,525	27,835	533,360

Table 6.64 - Illustrative AADT Range for State Roads (New August 2011)

Functional Class	County	Route	AADT Range, (1,000s)	Estimated Average Truck Volume (1,000s)
Interstate	Delaware	88	11 - 12	2.40
Arterial	Delaware	28	1 - 6	0.30
Collector	Delaware	357	2 - 4	0.02
Interstate	Broome	17	7 - 77	7.00
Arterial	Broome	26	2 - 33	1.00
Collector	Broome	41	1	0.01
Interstate	Cattaraugus	86	8 - 13	2.00
Arterial	Cattaraugus	219	6 - 11	1.00
Collector	Cattaraugus	353	1 - 6	0.20

AADT and Trucks rounded to the nearest 1,000.

Source: NYSDOT 2011

Although truck traffic is expected to significantly increase in certain locations, most of the projected trips would be short. The largest component of the truck traffic for horizontal drilling would be for water deliveries, and these would involve very short trips between the water procurement area and the well pad. Since the largest category of truck trips involve water trucks (600 of 1,148 heavy truck trips; see Table 6.60), it is anticipated that the largest impacts from truck traffic would be near the wells under construction or on local roadways.

Development of the high-volume hydraulic fracturing gas resource would also result in direct and indirect employment and population impacts, which would increase traffic on area roadways. The Department, in consultation with NYSDOT, will undertake traffic monitoring in the regions where well permit applications are most concentrated. These traffic studies and monitoring efforts will be conducted and reviewed by NYSDOT and used to inform the development of road use agreements by local governments, road repairs supported by development taxes, and other mitigation strategies described in Chapter 7.13.

6.11.3 Damage to Local Roads, Bridges, and other Infrastructure

As a result of the anticipated increase in heavy- and light-duty truck traffic, local roads in the vicinity of the well pads are expected to be damaged. Road damage could range from minor fatigue cracking (i.e., alligator cracking) to significant potholes, rutting, and complete failure of the road structure. Extra truck traffic would also result in extra required maintenance for other local road structures, such as bridges, traffic devices, and storm water runoff structures. Damage could occur as normal wear and tear, particularly from heavy trucks, as well as from trucks that may be on the margin of the road and directly running over culverts and other infrastructure that is not intended to handle such loads.

As discussed in Section 2.3.14, the different classifications of roads are constructed to accommodate different levels of service, defined by vehicle trips or vehicle class. Typically, the higher the road classification, the more stringent the design standards and the higher the grade of materials used to construct the road. The design of roads and bridges is based on the weight of vehicles that use the infrastructure. Local roads are not typically designed to sustain a high level of vehicle trips or loads and thus oftentimes have weight restrictions.

Maintenance and repair of the road infrastructure in New York currently strains the limited budgets of the New York State Department of Transportation (NYSDOT) as well as the county and local agencies responsible for local roads. Heavy trucks generally cause more damage to roads and bridges than cars or light trucks due to the weight of the vehicle. A general “rule of thumb” is that a single large truck is equivalent to the passing of 9,000 automobiles (Alaska Department of Transportation and Public Facilities 2004). The higher functional classes of roads, such as the interstate highways, generally receive better and more frequent maintenance than the local roads that are likely to receive the bulk of the heavy truck traffic from the development of shale gas.

Some wells would be located in rural areas where the existing roads are not capable of accommodating the type of truck or number of truck trips that would occur during well development. In addition, intersections, bridge capacities, bridge clearances, or other roadway features may prohibit access to a well development site under current conditions. Applicants would need to improve the roadway to accommodate the anticipated type and amount of truck traffic, which would be implemented through a road use agreement with the local municipality. This road use agreement may include an excess maintenance agreement to provide compensation for impacts. These criteria are discussed further in Section 7.13, Mitigating Transportation and

Road Use Impacts. Section 7.13 also discusses additional ways that compensatory mitigation may be applied to pay for damages.

Actual costs associated with local roads and bridges cannot be determined because these costs are a factor of (1) the number, location, and density of wells; (2) the actual truck routes and truck volumes; (3) the existing condition of the roadway; (4) the specific characteristics of the road or bridge (e.g., the number of lanes, width, pavement type, drainage type, appurtenances, etc.); and (5) the type of treatment warranted. However, based on a sample of 147 local bridges with a condition rating of 6 (i.e., Fair to Poor) in Broome, Chemung, and Tioga counties, estimates of replacement costs could range from $100,000 to $24 million per bridge, and averaged $1.5 million per bridge. The NYSDOT estimates that bridges with a condition rating of 6 or below would be impacted by the projected increase in truck traffic, resulting in accelerated deterioration, and warrant replacement. Because these routes were often built to lower standards, heavy trucks would have a much greater impact than other types of traffic.

According to the NYSDOT, the costs of repair to damaged pavement on local roads also varies widely depending on the type of work necessary and the characteristics of the road. Low-level maintenance treatments such as a single course overlay, would range from $70,000 to $150,000 per lane mile. Higher-level maintenance such as rubberizing and crack and seat rehabilitation would range from $400,000 to $530,000 per lane mile. Full-depth reconstruction can range from $490,000 to $1.9 million per lane mile.

6.11.4 Damage to State Roads, Bridges, and other Infrastructure

For roads of higher classification in the arterial or major collector categories, the general construction of the roads would be adequate to sustain the projected travel of heavy- and light-trucks associated with horizontal drilling and high-volume hydraulic fracturing. However, there would be an incremental deterioration of the expected life of these roads due to the estimated thousands of vehicle trips that would occur because of the increase in drilling activity. These larger roads are part of the public road network and have been built to service the areas of the state for passenger, commercial, and industrial traffic; however, the loads and numbers of heavy trucks proposed by this action could effectively reduce the lifespan of several roads, requiring unanticipated and early repairs or reconstruction, which would burden of the State and its taxpayers.

When the cumulative and induced impacts of the total high-volume hydraulic fracturing gas development are considered, the resulting traffic impacts can be considerable. The principal cumulative traffic impacts would occur during drilling and well development. Impacts on the road, bridge, and other infrastructure would be primarily from the cumulative impact of heavy trucking.

Actual costs to roads of higher functional classification cannot be determined because these costs are a factor of (1) the number, location and density of wells; (2) the actual truck routes and truck volumes; (3) the existing condition of the roadway; (4) the specific characteristics of the road or bridge (e.g., the number of lanes, width, pavement type, drainage type, appurtenances, etc.); and (5) the type of treatment warranted, similar to the local roads discussed above.

However, based on a sample of 166 state bridges with a condition rating of 6 (i.e., Fair to Poor) in Broome, Chemung, and Tioga counties, estimates of replacement costs could range from $100,000 to $31 million per bridge, and averaged $3.3 million per bridge. The NYSDOT estimates that bridges with a condition rating of 6 or below would be impacted by the projected increase in truck traffic, resulting in accelerated deterioration, and warrant replacement.

According to the NYSDOT, the costs of repair to damaged pavement on state roads also varies widely depending on the type of work necessary and the characteristics of the road. Low-level maintenance treatments such as a single-course overlay, would range from $90,000 to $180,000 per lane mile. Higher-level maintenance such as rubberizing and crack and seat rehabilitation would range from $540,000 to $790,000 per lane mile. Full depth reconstruction can range from $910,000 to $2.1 million per lane mile.

Depending on the volume and location of high-volume hydraulic fracturing, there is a possibility that a number of bridges and certain segments of state roads would require higher levels of maintenance and possibly replacement. The extent of such road work that would be attributable to high-volume hydraulic fracturing cannot be calculated because the proportion of truck and vehicular traffic attributable to such operations compared to truck and vehicular traffic attributable to other industries on any particular road would vary significantly. On collectors and minor arterials, there is a potential for greater impacts from this activity because these routes were often built to lower standards, and thus, heavy trucks would have a much greater impact than other types of traffic. As a result, actual contribution of heavy trucks to road and bridge deterioration would be greater than suggested by their proportion to total traffic. Conversely, any additional traffic on higher functional class roads, and especially interstates and major arterials, would result in little impact because these roads were built to higher construction and pavement standards.

6.11.5 Operational and Safety Impacts on Road Systems

An increase in the amount of truck traffic, and vehicular traffic in general, traveling on both higher and lower level local roads would most likely increase the number of accidents and breakdowns in areas experiencing well development. These potential breakdowns and accidents would require the response of public safety and other transportation-related services (e.g., tow trucks). Local road commissions and the NYSDOT would also likely incur costs associated with operational and safety improvements.

The costs of implementing operational and safety improvements on local roads would vary widely depending on the type of treatment required. Improvements on turn lanes could cost from $17,000 to $34,000, and the provision of signals and intersection could cost from approximately $35,000 for the installation of flashing red/yellow signals and from $100,000 to $150,000 for the installation of three-color signals.

The costs of addressing operational and safety impacts on state roads also would vary widely depending on the type of treatment required. The most common treatments include constructing turn lanes, with costs ranging from $20,000 to $40,000 on state roads, and installing signals and intersections, where costs range from approximately $35,000 for the installation of flashing red/yellow signals and from $100,000 to $150,000 for the installation of three-color signals.

The cost of addressing capacity and flow constraints stemming from high levels of truck traffic or direct and indirect employment and population traffic volumes are much greater, however, and might approach $1 million per lane per mile (roughly the cost of full reconstruction), not including the costs of acquiring rights-of-way.

6.11.6 Transportation of Hazardous Materials

Vertical wells do not require the volumes of chemicals that would require consideration of hazardous chemicals beyond the use of diesel fuel for the equipment on the surface. The truck traffic supporting the development of the horizontal wells involving high-volume hydraulic fracturing would be transporting a variety of equipment, supplies, and potentially hazardous materials.

As described in Section 5.4 of the SGEIS, fracturing fluid is 98% freshwater and sand and 2% or less chemical additives. There are 12 classes of chemical additives that could be in the hazardous waste water being trucked to or from a location. Additive classes include: proppant, acid, breaker, bactericide/biocide, clay stabilizer/control, corrosion inhibitor, cross linker, friction reducer, gelling agent, iron control, scale inhibitor, and surfactant. These classes are described in full detail in Section 5.4, Table 5.6. Although the composition of fracturing fluid varies from one geologic basin or formation to another, the range of additive types available for potential use remains the same. The selection may be driven by the formation and potential interactions between additives, and not all additive types would be utilized in every fracturing job (see Section 5.4). Table 5.7 (Section 5.4) shows the constituents of all hydraulic fracturing-related chemicals submitted to NYSDEC to date for potential use at shale wells within New York. Only a handful of these chemicals would be utilized at a single well. Data provided to NYSDEC to date indicates that similar fracturing fluids are needed for vertical and horizontal drilling methods.

Trucks transporting hazardous materials to the various well locations would be governed by USDOT regulations, as discussed in Section 5.5 and Chapter 8. Transportation of any hazardous materials always carries some risks from spills or accidents. Hazardous materials are moved daily across the state without incident, but the additional transport resulting from horizontal drilling poses an additional risk, which could be an adverse impact if spills occur.

6.11.7 Impacts on Rail and Air Travel

The development of high-volume hydraulic fracturing natural gas would require the movement of large quantities of pipe, drilling equipment, and other large items from other locations and from manufacturing sites that are likely far away from the well sites. Rail provides an inexpensive and efficient means of moving such material. The final movement, from rail depots to the well sites, would be accomplished with large trucks. The extent of rail and the choice of unloading locations depends on the well sites and cannot be predicted at this time. However, the use of rail to transport materials would have several predictable results:

- Total truck traffic would decrease;
- Truck traffic near the rail terminals would increase,
- Truck traffic on the arterials between the terminals and well fields would increase.

These positive and negative impacts would likely alleviate some impacts but might exacerbate impacts in neighborhoods along the routes to and from the rail centers. These impacts would require examination as part of road use agreements.

The heavy, bulky, equipment utilized for horizontal drilling would not likely be transported by air. However, the large numbers of temporary workers that the industry would employ would likely utilize the network of small airports and commuter airlines that service New York State. This would increase the traffic to and from these airports. None of the regional airports in New York State are at capacity, so the air travel is not expected to be a significant impact. In fact, the extra economic activity would be positive. However, residents that are along approach and departure corridors would experience more noise from increased service by airplanes.

6.12 Community Character Impacts[408]

High-volume hydraulic fracturing operations could potentially have a significant impact on the character of communities where drilling and production activities would occur. Both short-term and long-term, impacts could result if this potentially large-scale industry were to start operations. Experiences in Pennsylvania and West Virginia show that wholesale development of

[408] Section 6.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

the low-permeable shale reserves could lead to changes in the economic, demographic, and social characteristics of the affected communities.

While some of these impacts are expected to be significant, the determination of whether these impacts are positive or negative cannot be made. Change would occur in the affected communities, but how this change is viewed is subjective and would vary from individual to individual. This section, therefore, seeks to identify expected changes that could occur to the economic and social makeup of the impacted communities, but it does not attempt to make a judgment on whether such change is beneficial or harmful to the local community character.

The amount of the change in community character that is expected to occur would be impacted by several factors. However, the most important factors would be the speed at which high-volume hydraulic fracturing activities would occur and the overall level of the natural gas activities. Slow, moderate growth of the industry, if it were spread over several years, would generate much less acute impacts than rapid expansion over a limited time. Community character is constantly in a state of flux; a community's sense of place is constantly revised and adapts as social, demographic, and economic conditions change. When these changes are gradual, residents are given time to adapt and accommodate to the new conditions and typically do not view them as negative. When these changes are abrupt and dramatic, residents typically find them more adverse.

If the high-volume hydraulic fracturing operations reach some of the more optimistic development levels described in previous sections, the size and structure of the regional economies could be influenced by this new industry. Local communities that have experienced declining employment and population levels for decades could quickly become some of the fastest growing communities in the state. Traditional employment sectors could decline in importance while new employment sectors, such as the natural gas extraction industry and its suppliers, could expand in importance. Employment opportunities would increase in the communities and the types of jobs offered would change.

Total population would increase in the communities and the demographic makeup of these populations would change. In-migration resulting from the high-volume hydraulic fracturing operations would bring a racially and ethnically diverse workforce into the area. Most of the new population would be working age or their dependents. In addition, most of the employment opportunities created would be for skilled blue collar jobs.

In addition to employment and demographic impacts, the proposed high-volume hydraulic fracturing would greatly increase income and earnings throughout affected communities. Royalty payments to local landowners, increased payroll earnings from the natural gas industry, added profits to firms that supply the natural gas industry, and added earnings from all of the induced economic activity that would occur in the communities would all add to the affluence of the region. While total income in the communities would increase, this added income and wealth would not be evenly distributed. Landowners that lease out their subsurface mineral rights would benefit financially from the high-volume hydraulic fracturing operations; however, those residents that do not own the subsurface mineral rights or chose not to exploit these rights would not see the same financial benefits. Some entrepreneurs and property owners would see large financial gains from the increase in economic activity, other residents may experience a rise in living expenses without enjoying any corresponding financial gains.

In some areas, the housing market would experience an increase in value and price if there is not sufficient outstanding supply to meet the increased demand. Existing property owners would most likely benefit; residents not already property owners could experience price rises and difficulties entering the market. Additional housing would most likely be constructed in response to increased demand, and in certain instances such development could occur on currently undeveloped land. Activities that achieve lower financial returns on property, such as agriculture, may be considered less desirable compared to housing developments. While at the same time, farmers who own large tracts of land could also benefit greatly from the royalty payments on the new natural gas wells.

Local governments would see a rapid expansion in the amount of sales tax and property tax generated by gas drilling and would now have the funding to complete a wide range of community projects. At the same time, the large influx of population would demand additional community services and facilities. Existing facilities would likely become overcrowded, and additional new facilities would have to be built to accommodate this new population.

Commuting patterns in the affected communities would also change. An increase in traffic both from the added truck transportation and from the additional population would likely increase traffic on certain areas roadways and, as further explained in the Transportation subchapter, would likely lead to the need for road improvements, reconstruction and repairs.

Ambient noise levels in the communities would likely increase as a direct result of drilling and additional traffic at the well pads, and as a result of increased development in the region (see Section 2.3.13). Aesthetic resources and viewsheds could be at least temporarily impacted and changed during well pad construction and development (see Section 2.3.12).

6.13 Seismicity[409]

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 SGEIS presents background seismic information for New York. Concerns associated with the seismic events produced during hydraulic fracturing are discussed below.

6.13.1 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.

[409] Alpha, 2009, Section 7; discussion was provided for NYSERDA by Alpha Environmental, Inc., and Alpha’s references are included for informational purposes.

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.

6.13.1.1 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 would 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 2,500 feet of the treatment well; the distance is dependent upon formation properties and background noise level (Pinnacle; “FracSeis;” August 11, 2009).

6.13.1.2 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 would 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; and
- 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 (SMU) 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 SMU 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 SMU (2009) states that the research suggests that the earthquakes seem to have been caused by injections associated with a deep production brine disposal well, and not with hydraulic fracturing operations.

6.13.1.3 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 has been 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 would 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 would be unfelt at the surface and no damage would 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.

6.13.1.4 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.

6.13.2 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, NY in 1971. The studies indicated that the likely cause of the earthquakes was the injection of fluid for production brine disposal for the incidents in Texas, and the injection of fluid for solution mining for the incidents in Dale, NY

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 would continue to provide additional data to monitor and evaluate the likely sources of seismic events that are felt.

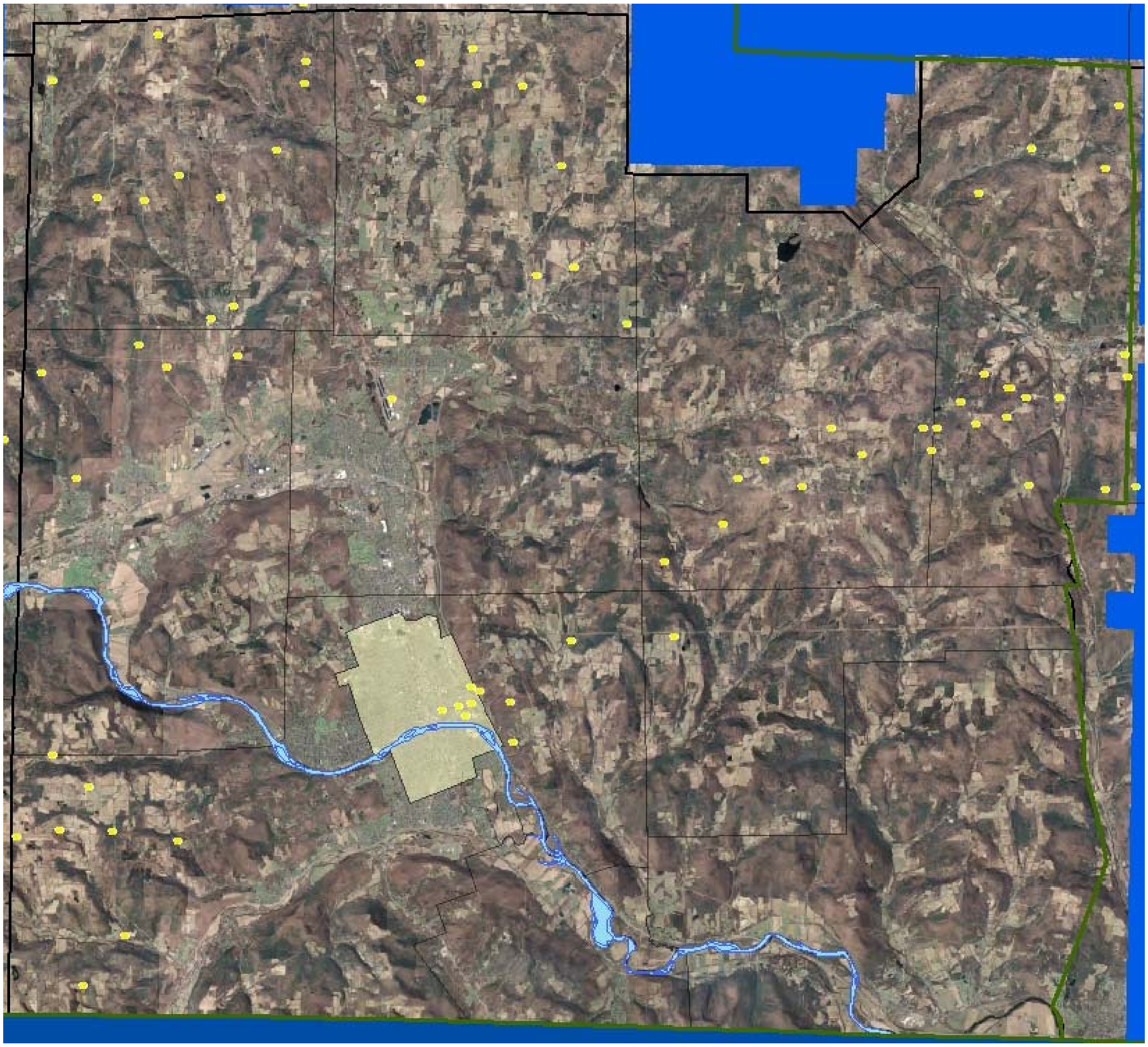
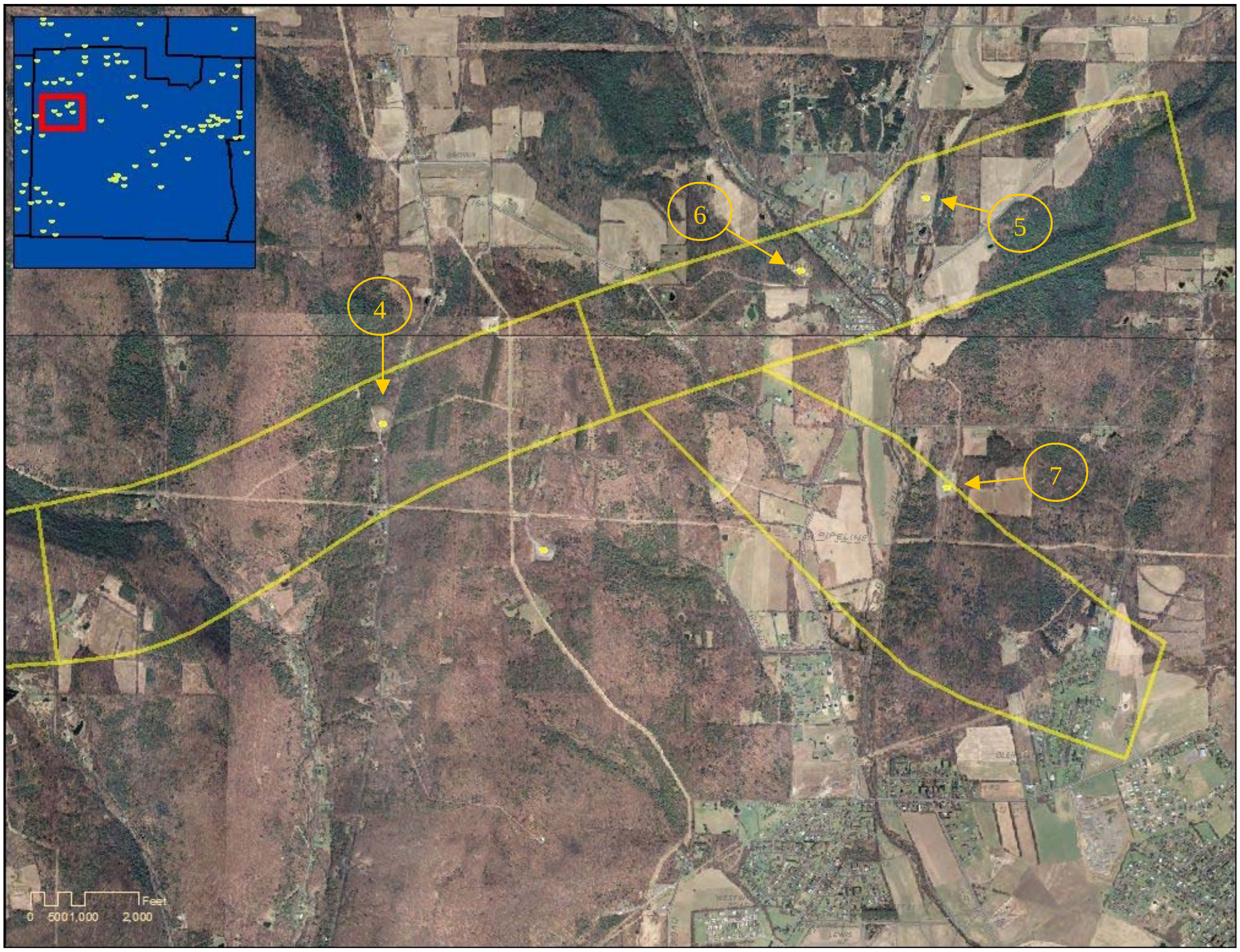


Photo 6.9 The following series of photos shows Trenton-Black River wells in Chemung County. These wells are substantially deeper than Medina wells, and are typically drilled on 640 acre units. Although the units and well pads typically contain one well, the size of the well units and pads is closer to 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 6.10 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 map below shows wells in the eastern end of the field. Note the relative proportion of well pads to area of entire well units. The unit sizes shown are approximately 640 acres, similar to expected Marcellus Shale multi-well pad units.



Photos 6.11 Well #4 (Hole number 22853) was a vertical completed in February 2001 at a true 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 Trenton-Black River well fenced area is typically covered with gravel.

Rhodes 1322 11/13/2001

Rhodes 1322 5/6/2009

Photos 6.12 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 6.13 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 6.14 Well #7 (Hole number 23134) was completed as a horizontal well in 2004 to a true vertical depth of 9,695 and a true measured 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

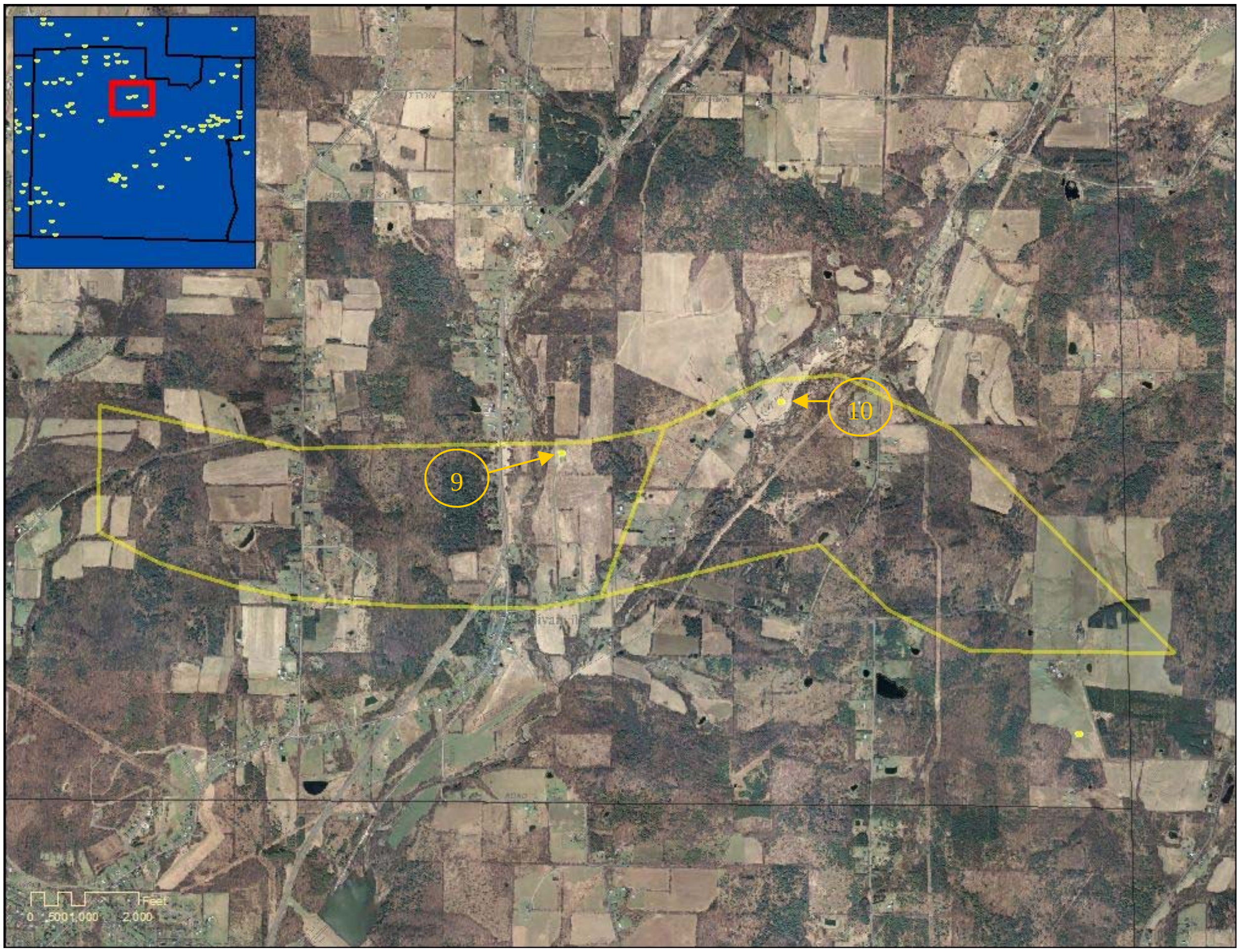
Soderblom #1 8/19/2004

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Photo 6.15 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 6.16 Well #9 (Hole number 23228) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a true vertical depth of 9,461 and a true measured depth of 12,550 feet. The well unit is approximately 622 acres.

Little 1 10/6/2005

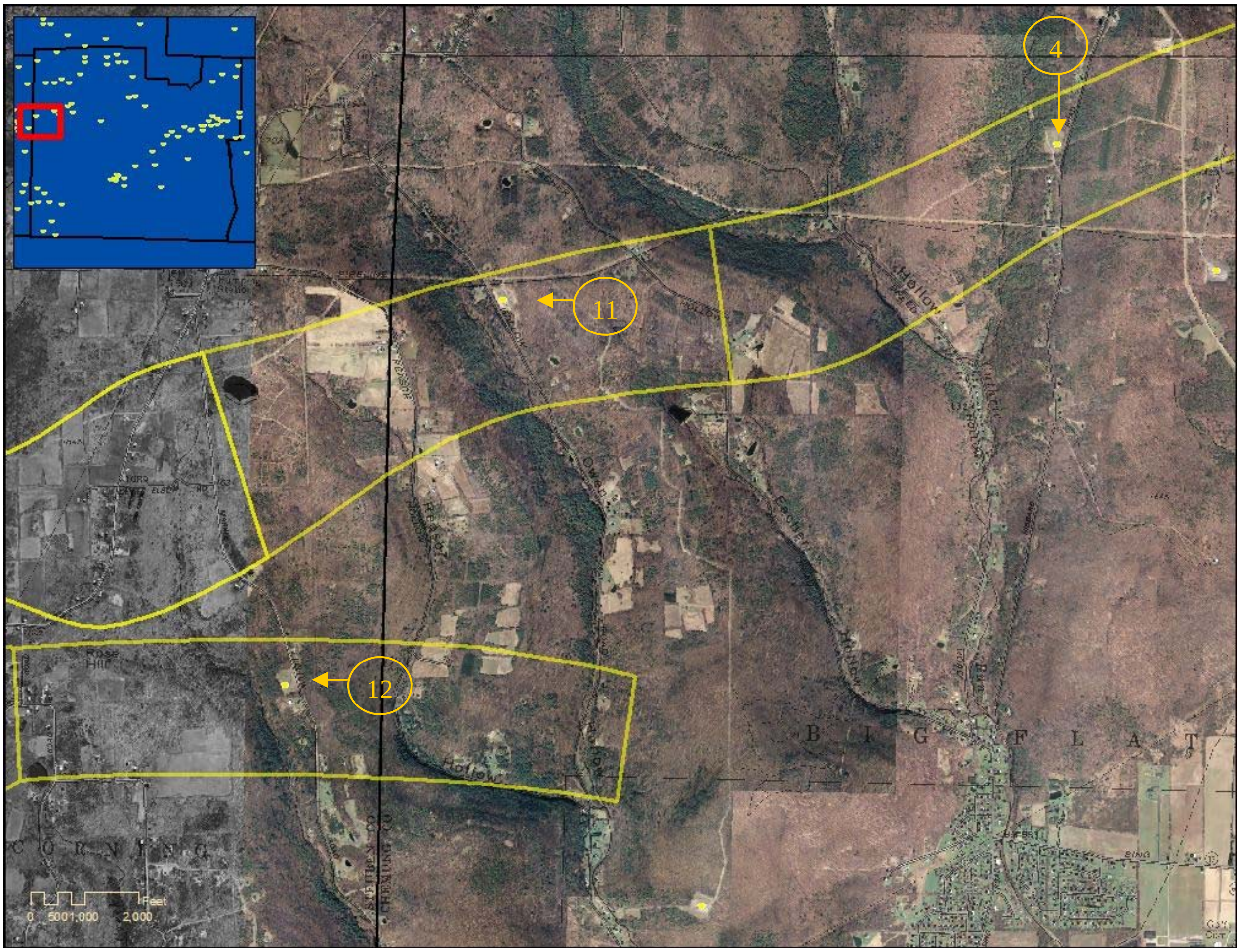
Little 1 11/3/2005

Photos 6.17 Well #10 (Hole number 23827) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a true vertical depth of 9,062 and a true measured depth of 13,360 feet. The production unit is approximately 650 acres.

Hulett #1 10/5/2006

Hulett #1 5/6/2009

Photo 6.18 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 6.19 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 6.20 Well #12 (Hole number 22871) was completed in 2002 as a horizontal well to a true vertical depth of 9,955 feet and a true measured 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

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NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Chapter 7

Mitigation Measures

Final

Supplemental Generic Environmental Impact Statement

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Chapter 7 – Mitigation Measures

FIGURES

TABLES

PHOTOS

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Chapter 7 EXISTING AND RECOMMENDED MITIGATION MEASURES

Many of the potential impacts identified in Chapter 6 are addressed by existing regulatory programs, both within and outside of the Department. These are identified and described in this chapter, along with recommendations for additional mitigation measures to address additional potential significant adverse environmental impacts from high-volume hydraulic fracturing, which is often associated with horizontal drilling and multi-well pad development. These additional recommended mitigation measures, if adopted, can be imposed as enhanced procedures, permit conditions and/or new regulations. In addition, the proposed EAF Addendum in Appendix 6 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 in some instances may 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 and the mitigation measures identified therein. This chapter identifies and discusses:

1) mitigation of impacts not addressed by the 1992 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 1992 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 oil and gas 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."[410]

[410] ECL §23-0305(8)(d).

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 . . ."[411]

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 (NFRM), which is preferred by the Department for purposes of the development of gas reserves as described in this document and are proposed to be enforced as permit conditions until further regulatory guidance or regulations are formally adopted. Mitigation of cumulative impacts is also addressed.

7.1.1.1 Department Jurisdictions

Degradation of Water Use

Currently, the Department's regulatory authority to regulate water withdrawals outside the Great Lakes Basin and Long Island is limited to withdrawals for public water supply purposes. However, the Department proposes to require as a permit condition that applicants identify the source of the water it intends to use in high-volume hydraulic fracturing operations and report annually on the aggregate amount of water it has withdrawn or purchased. Furthermore, the Department also intends to require that permittees employ the NFRM, as described below, as a mitigation measure to avoid degradation of water quality due to water withdrawals from high-volume hydraulic fracturing.

The Water Resources bill, which was recently passed by both houses of the legislature and awaits the Governor's signature to become law, would extend the Department's authority to regulate all water withdrawals over 100,000 gpd throughout all of New York State. This bill

[411] ECL §3-0301(1)(b).

applies to all such withdrawals where water would be used for high-volume hydraulic fracturing. Withdrawal permits issued in the future by the Department, pursuant to the regulations implementing this law, would include conditions to allow the Department to monitor and enforce water quality and quantity standards and requirements. These standards and requirements may include: passby flow; fish impingement and entrainment protections; protections for aquatic life; reasonable use; water conservation practices; and evaluation of cumulative impacts on other water withdrawals.

Public Water Supply - New York State currently regulates public drinking water supply ground and surface water withdrawals through the public water supply permit program.[412] These limited water supply permit programs help to protect and conserve available water supplies.

Other Water Withdrawals - The Department also regulates non-public water supply withdrawals in Long Island counties from wells with pumping capacities in excess of 45 gpm. (ECL 15-1527). All water withdrawals within New York's portion of the Great Lakes Basin of 100,000 gpd or more (30-day average) must register with the Department (ECL 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 water body's designated best use. Determination of an appropriate passby flow needs to be done on a case by case basis. However, guidance to clarify the application of the narrative water quality standard for flow has not yet been issued. For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit condition as a protection measure pending completion of guidance.

412 ECL Article 15, Title 15.

Water Withdrawal Reporting - Pursuant to Title 33 of Article 15 of the ECL, any entity that withdraws, or that has the capacity to withdraw, groundwater or surface water in quantities greater than 100,000 gpd must file an annual report with the Department. Inter-basin diversions must be reported on the same form.

Water Withdrawal Regulations

The Department primarily addresses the withdrawal of water and its potential impacts in the following regulations:

- 6 NYCRR Part 601: Water Supply;
- 6 NYCRR Part 602: Long Island Wells; and
- 6 NYCRR Part 675: Great Lakes Withdrawal Registration Regulations.

The requirements of 6 NYCRR Part 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 Part 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 shale formations being considered for potential high-volume hydraulic fracturing is located within the Great Lakes Basin. Registration is required for non-agricultural purposes in excess of 100,000 gpd (30-day consecutive period). An application for registration of a 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.

Protection of Aquatic Ecosystems

In addition to provisions in the Water Resources Law regarding protection of aquatic ecosystems, the Environmental Conservation Law includes other programs that protect aquatic habitat. 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 Department has authority to control the use and protection of the waters of New York State through 6 NYCRR 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 water body integrity. Part 608 does not regulate disturbances of the many streams classified as "C" or below.

7.1.1.2 Other Jurisdictions - Great Lakes-St. Lawrence River Basin Water Resources Compact

The Great Lakes-St. Lawrence River Basin Water Resources Compact (Compact) was signed into law on October 3, 2008 through Public Law 110-342. The Great Lakes-St. Lawrence River Basin Water Resources Council (Council), whose membership includes eight Great Lakes States, was established by the Compact on December 8, 2008. The Compact prohibits the bulk transport of water from that basin in containers larger than 5.7 gallons. In addition, effective December 8, 2008, the Compact[413] prohibits any new or increased diversion of any amount of water out of the Great Lakes Basin with certain limited exceptions. Also, any proposed new or increased withdrawal of surface or groundwater that will result in a consumptive use of 5 million gpd or greater averaged over a 90-day period requires prior notice and consultation with the Council and the Canadian Provinces of Ontario and Quebec.

Within five years of the effective date of the Compact, New York State must implement a program that ensures that, all new and increased water withdrawals must comply with the

[413] ECL Article 21, Title 10.

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;
2) No significant adverse individual or cumulative impacts to the quantity of the waters and water-dependent natural resources;
3) Implementation of environmentally sound and economically feasible water conservation measures;
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.

The Great Lakes Council does not have regulatory authority similar to that held by SRBC and DRBC to review water withdrawals and uses and require mitigation of environmental impacts. However, the Council has specific authority for the review and/or approval of certain new and increased water withdrawals. Review by the 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 SRBC and the 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. Any amount of surface water withdrawn to develop shale formations requires 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 usage. The DRBC Water Code[414] 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:

[414] 18 CFR Part 410.

Table 7.1 - Regulations Pertaining to Watershed Withdrawal (Revised July 2011)[415]

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 §665 6 NYCRR §670 6 NYCRR §671 6 NYCRR §672 6 NYCRR §701	6 NYCRR §608 6 NYCRR §666 6 NYCRR §701	6 NYCRR §663 6 NYCRR §664 6 NYCRR §665	6 NYCRR §595 6 NYCRR §608 6 NYCRR §666	6 NYCRR §601 6 NYCRR §602
SRBC	Reg. of Projects §806.30 Reg. of Projects §801.3 Reg. of Projects §802.23	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

415 Adapted from Alpha, 2009.

- Allocation of water resources, including three major reservoirs for the NYC 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; and
- 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.[416] 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 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 River 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

[416] 18 CFR Part 410.

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.[417]

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 which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, or odor of the waters."[418]

Impacts to Wetlands - DRBC regulations concerning potential impacts to downstream wetlands are located in the Delaware River Basin Water Code[419] 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;

417 DRBC Water Code, Article 3.10.3.A.2.e.

418 DRBC Water Code, Article 3.40.4.A.1.

419 18 CFR 410.

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.[420] 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 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 operators of individual wells or groups of wells that withdraw an average of 10,000 gpd or more during any 30-day period from the underground waters of the Basin must register their wells with the designated agency of the

[420] DRBC Water Code, Article 2.350.4.

state where the well is located. Registration may be filed by the agents of operators, 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; the Department; or the PADEP (DRBC Water Code, Article 2.20.7).

Groundwater withdrawals from aquifers in the Basin that exceed 100,000 gpd 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 5 % 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).

SRBC 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[421] 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 its 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;

[421] 18 CFR, Parts 801, 806, 807, and 808.

- 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; and
- Aquifer testing protocol.

Impacts to Aquatic Ecosystems - SRBC regulations concerning the protection of fish and wildlife are located in the SRBC Regulation of Projects.[422] 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 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."[423] The SRBC 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

[422] 18 CFR Parts 801, 806, 807, and 808.

[423] SRBC Regulation of Projects, Article 806.23.b.2.

is occurring. The methods by which passby flows are determined for use as impact mitigation are described below.

Impacts to Wetlands - Sponsors of 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.[424]

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

Protecting Stream Flows –DRBC 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 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.[425] For most streams, the Q7-10 flow is less than 10% of the

[424] SRBC Regulation of Projects, Article 806.14.

[425] Camp, Dresser and McKee, 1986.

average annual flow and may result in degradation of aquatic communities if it becomes established as the only flow protected in a stream.[426]

Protecting Stream Flows – SRBC Method

The SRBC requires that passby flows, i.e., 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 groundwater 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."[427] 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 % 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 % 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 % of the Q7-10 low flow; and

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.

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426 Tennant 1976a,b.

427 SRBC, Policy 2003-01.

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 5 % loss of habitat. For HQ Waters, withdrawals may not cause greater than 5 % loss of habitat as well; however, a habitat loss of 7.5 % 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,[428] CWF Waters, withdrawals may not cause greater than a 10 % loss of habitat. For Classes C and D, CWF Waters, withdrawals may not cause greater than a 15 % loss of habitat. For areas of the Susquehanna River Basin not covered by the above regulations, the following shall apply:

1) On all EV and HQ streams, and those streams with naturally reproducing trout populations, a passby flow of 25 % 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 % 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 % 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; and

5) The SRBC is currently reevaluating the passby requirements described above and draft changes will likely be proposed sometime in 2011.

[428] Water classifications referenced in this section are those established by State of PA which are not equivalent to NYS stream classifications.

Protecting Stream Flows - NFRM

The NFRM is an alternative to the current 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. The Department proposes to require the NFRM as a permit condition and mitigation measure to ensure that water withdrawals, including those from the Delaware and Susquehanna River basins, in connection with high-volume hydraulic fracturing do not result in any significant adverse environmental impacts.

To assure adequate surface water flow when water withdrawals are made, provisions would be required to be made to 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 monthly flow exceedance values. Monthly flow exceedance value describes the percentage probability that the calculated streamflow statistic will be exceeded at any time during the month. For example, the Q60 monthly flow exceedance value is the calculated instantaneous flow that will be exceeded 60% of the time during a specific month. As described below, appropriate flow exceedance values will vary by month and will depend on the watershed size upstream from the water withdrawal.

The purpose of the NFRM 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, flow exceedance values are easily calculated. The foundation of the NFRM is based on the New England Aquatic Baseflow Standard.[429] Commonly referred to as the ABF, or New England Flow Policy, this method is a component of the broader U.S. Fish and Wildlife Service's New England Flow Policy. The basic assumption of the method is that varying flows based on monthly flow exceedance values 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

[429] Larsen, 1981.

parameters including: depth, width, velocity, substrate, side channels, bars and islands, cover, migration, temperature, invertebrates, fishing and floating, and aesthetics.

The objective of the NFRM 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.[430] Native aquatic species possess life history traits that enable individuals to survive and reproduce within a certain range of environmental variation. Changes in channel morphology and aquatic habitat that exceed this range of variation will result in community shifts that are detrimental to the native aquatic ecosystem. Flow depth and velocity, water temperature, substrate size distribution and oxygen content are among the myriad of environmental attributes known to shape the habitat that control aquatic and riparian species distributions. Fluvial processes maintain a dynamic mosaic of aquatic habitat structures which create environmental factors that sustain diverse biotic assemblage; therefore, maintaining a natural flow regime is recognized as a primary driving force within riverine ecosystems. The survival of native species and natural communities is reduced if environment flows are pushed outside the range of their natural variability due to the resultant shifts in community structure. The NFRM manages our natural aquatic resources within their range of natural variability that maintains diverse, resilient, productive, and healthy ecosystems. The result is that passby flows calculated under this method emulate the natural hydrograph, including flushing flows that define and maintain the stream habitat suitable for aquatic biota. Research by Estes[431] and Reiser et al.[432] supports the need for these channel-maintaining flows.

There are limitations associated with the NFRM 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[433] 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 natural flow conditions (e.g.,

[430] IFC, 2004.

[431] Estes, 1984.

[432] Reiser, et al., 1988.

[433] Estes, 1998.

releases from dams) will influence the calculation of passby flows and may not support fishery management objectives.

A. PASSBY FLOW METHODOLOGY: GENERAL CASE

Watersheds and associated waterways each have distinctive natural flow patterns with variable magnitude, duration, timing, and rate of change of flow rates and water levels. The NFRM preserves the inherent intra-annual variability associated with a natural flow pattern through the use of Q75 and/or Q60 monthly exceedance values for establishing passby flows as described below. The specific flow exceedance values of Q75 and Q60 were selected by Department staff using best professional judgment, based on research conducted by the State of Michigan (Zorn et al. 2008). The scientific framework for the Michigan work is the relationship between streamflow reductions and projected impact on resident fish populations. Regulatory decisions in Michigan regarding surface or groundwater withdrawals are designed to avoid an adverse resource impact to local stream ecosystems. Although Michigan methods vary from those described here, Michigan's requirements equate to flow exceedance values of approximately Q75 and Q60.

Waterways with substantial artificial alteration of stream flow by dams, weirs, bypasses, diversions, and water withdrawals or augmentation are different from waterways without manmade modifications to flow. As such, methods for determining appropriate passby flows are different for water bodies with "altered flow" and for water bodies with "natural flow." The instream flow requirements would be calculated in accordance with the methods described in the following sections depending on whether the flow is natural or altered, and gaged or ungaged.

1. Waterways with "Natural Flow"

Waterways that are not subject to substantial artificial modification of stream flow by dams, weirs, bypasses, diversions, and water withdrawals or augmentation would be considered to have "natural flow". The method for computing the passby flows at a specific project site depends on whether the project is located on a gaged or an ungaged waterway, as described below.

<u>Gaged Waterways</u> - If the proposed water withdrawal project location is on a waterway with a USGS streamflow gage, and if the project site's drainage area is between 50 and 200% of the

drainage area of the stream at the reference gage, a weighted flow exceedance estimate for the project site can be computed by using the drainage area ratio method. Streamflow statistics for a given month are estimated by:

$$Q_p = (A_p/A_g) \times Q_g$$

where Q_p is the flow exceedance value at the project site, Q_g is the flow exceedance value at the reference stream gage, A_p is the drainage area above the project site, and A_g is the drainage area above the reference stream gage. This equation assumes that the streamflow per unit area at the project site and reference gage are equal for any given month. Watershed drainage areas can be determined using the USGS StreamStats tool accessible at http://water.usgs.gov/osw/streamstats/ssonline.html.

Passby flows in gaged waterways with natural flow would be maintained such that:

a. when the watershed drainage area upstream from the water withdrawal location is greater than 50 square miles, the monthly passby flows would equal the monthly Q75 flow for the months of October through June and Q60 for the months of July through September; or

b. when the watershed drainage area upstream from the water withdrawal location is less than 50 square miles, the monthly passby flows would equal the monthly Q60 flow.

If the proposed water withdrawal project site is on a gaged stream but the site's drainage area is not between 50 and 200% of the drainage area of the stream at the gage, the passby flow should use the higher of the exceedance value estimates determined from either the reference gage in the watershed or the regional regression equation for ungaged waterways described below.

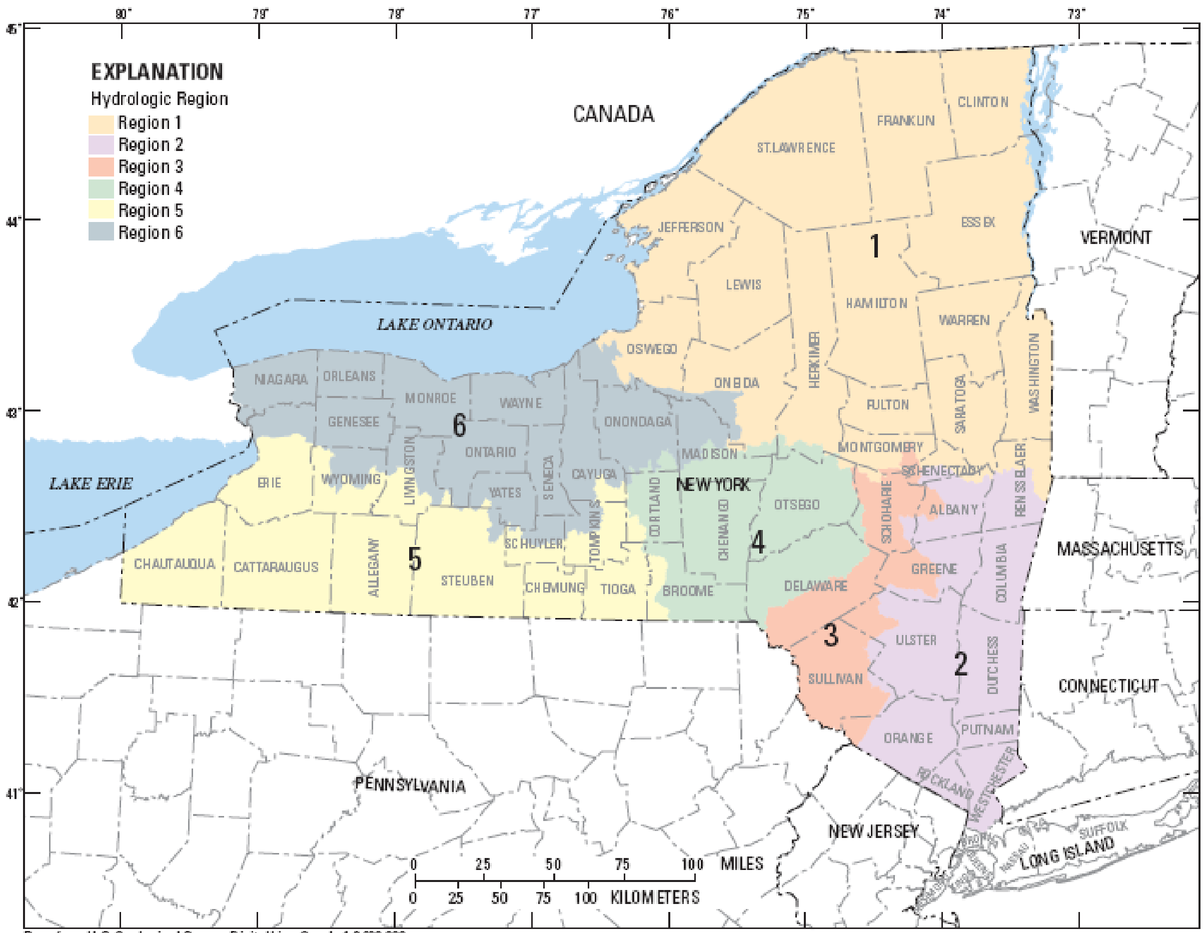
Ungaged Waterways - If the proposed water withdrawal project site is on a waterway that does not have an acceptable USGS streamflow gage as described above, passby flows can be determined using a regression analysis described in Department guidance documents.[434,435] Regression equations for estimating monthly flow exceedance values based on watershed areas

[434] DFWMR 2010.

[435] DFWMR 2010.

have been established for six hydrologic regions across New York State (Figure 7.1).[436] Monthly passby flows, in cubic feet per second (cfs), can be calculated for project sites on ungaged waterways by multiplying the upstream drainage area by the appropriate regional coefficient from Table 7.2, below. These coefficients reflect the same principles described in paragraphs 1.a and b, directly above. If the upstream drainage area lies entirely within a single hydrologic region, the calculation is straightforward. If, however, the drainage area extends into multiple hydrologic regions, flows would be calculated based on the percentage that lies within each hydrologic region. The resulting passby flow is the weighted sum of the values derived from each hydrologic region within the entire upstream drainage area.

Figure 7.1 - Hydrologic Regions of New York (New July 2011) (Taken from Lumia et al, 2006)



Base from U.S. Geological Survey, Digital Line Graph, 1:2,000,000
Universal Transverse Mercator projections, zone 18, NAD83

[436] Lumia et al. 2006.

Table 7.2 - Regional Passby Flow Coefficients (cfs/sq. mi.) (Updated August 2011)

REGION	Drainage Area (mi²)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Adirondack	< 50 mi²	1.17	1.02	1.54	3.19	1.75	0.99	0.64	0.48	0.47	0.83	1.36	1.32
	> 50 mi²	0.97	0.86	1.19	2.57	1.39	0.76	0.64	0.48	0.47	0.64	1.07	1.09
Lower Hudson	< 50 mi²	1.30	1.27	1.97	1.99	1.21	0.62	0.36	0.24	0.20	0.41	0.89	1.48
	> 50 mi²	0.97	0.90	1.57	1.58	0.94	0.47	0.36	0.24	0.20	0.25	0.64	1.09
Catskill	< 50 mi²	1.23	1.07	1.93	2.57	1.48	0.77	0.44	0.28	0.32	0.61	1.51	1.63
	> 50 mi²	0.93	0.81	1.37	2.04	1.15	0.56	0.44	0.28	0.32	0.40	0.94	1.21
Susquehanna	< 50 mi²	1.23	1.11	1.94	2.28	1.09	0.55	0.35	0.23	0.22	0.39	1.00	1.49
	> 50 mi²	0.94	0.84	1.49	1.85	0.81	0.42	0.35	0.23	0.22	0.27	0.64	1.15
Southern Tier	< 50 mi²	1.02	0.92	1.77	2.07	0.85	0.42	0.29	0.21	0.20	0.40	0.85	1.33
	> 50 mi²	0.66	0.50	1.34	1.49	0.67	0.32	0.29	0.21	0.20	0.28	0.44	0.99
Lake Plains	< 50 mi²	0.93	1.00	1.66	1.46	0.69	0.34	0.22	0.17	0.17	0.25	0.52	1.01
	> 50 mi²	0.68	0.75	1.20	1.13	0.55	0.28	0.22	0.17	0.17	0.18	0.31	0.69

The passby flow requirement described above, if imposed via permit condition and/or regulation, would fully mitigate any potential significant adverse impact from water withdrawals associated with high-volume hydraulic fracturing in "Natural Flow" waterways.

2. Waterways with "Altered Flow"

Waterways would be considered to have "altered flow" if more than 25 % of the drainage area above a proposed project is upstream of a dam, weir, bypass, diversion, or other controlled artificial flow modification.[3] Watershed drainage areas can be determined using the USGS StreamStats tool accessible at http://water.usgs.gov/osw/streamstats/ssonline.html. Passby flows within altered waterways would be determined on a case-by-case basis using Department staff's best professional judgment. Wherever possible, passby flows in altered waterways will provide flow patterns that emulate the annual flow hydrograph that would occur in the absence of all artificial flow alterations. The passby flow requirement, if imposed via permit condition and/or regulation, would mitigate any potential significant adverse impact from water withdrawals associated with high-volume hydraulic fracturing in "Altered Flow" waterways.

B. ALTERNATIVE PASSBY FLOWS

Alternative passby flows for water withdrawals associated with high-volume hydraulic fracturing that differ from those determined using the methodology described above may be approved on a case-by-case basis to protect endangered or threatened species in accordance with 6 NYCRR Part 182.

Protecting Other Surface Waters

As previously discussed in Chapter 6, water withdrawals from surface water bodies can have a direct impact upon aquatic habitats and other water users by the reduction of water volumes and levels. Smaller water bodies will see the greatest visible impact but even small level changes to large water bodies can sometimes be detrimental. A "safe or dependable" yield analysis is typically conducted for public water supplies to ensure the availability of water during extended drought conditions while also considering potential environmental impacts. Parameters such as stream inflow, usable storage volume, existing withdrawals, evaporation and precipitation amounts during prolonged drought periods arc used to calculate the amount of water that can be expected to be available for additional withdrawals. This same methodology can be applied to all types of withdrawals, including those to be used for hydraulic fracturing purposes. The key difference between public water supply and withdrawals for hydraulic fracturing is timing. Public water supplies typically require that a source be available at all times while other uses such as hydraulic fracturing may have the flexibility to limit their water withdrawals to times when surplus water is available.

Evaluation of Withdrawals from Surface Water Bodies

All withdrawals from surface water bodies will be evaluated to determine the impacts upon water quantity and level changes during extended drought conditions. The Department intends to require permittees to evaluate surface water bodies using the following equation:

$$\Delta V = I + P - W - E - R$$

Where ΔV = maximum change in storage, I = inflow into water body, P = precipitation onto water surface, W = existing and proposed water withdrawals, E = evaporation from water surface, and R = releases from water body. In some cases such as ponds, factors such as R may equal zero. The resulting maximum change in storage value (ΔV) shall be used to compute corresponding maximum water-level drawdowns. Site-specific SEQRA reviews should be conducted for withdrawals from ponds and lakes. Acceptable drawdown levels will be determined by Department on a case by case basis.

In accordance with the Department's Pump Test Recommendations, wetlands located within 500 feet of a proposed water withdrawal require monitoring during the pump test. Lowering of groundwater levels at or below a wetland is considered to be a significant impact.

7.1.1.5 Impact Mitigation Measures for Groundwater Withdrawals

The Department's DOW Recommended Pump Test Procedures for Water Supply Applications (http://www.dcc.ny.gov/lands/5003.html) will be used to evaluate proposed groundwater withdrawals for high-volume hydraulic fracturing.

As stated in the testing guidance, test results will be analyzed to evaluate:

- Impacts on neighboring water supplies

  Neighboring water supplies could be impacted if pumping of wells for Marcellus drilling requirements results in significant drawdown at offsite supplies. Site specific SEQRA reviews should be conducted for withdrawals from groundwater within 500 feet of private wells.

- Affects to the local groundwater basin

  The local groundwater basin can be similarly impacted resulting in lowering of groundwater levels. The range of impacts could vary from a lowering of water levels to a lowering of water levels to below pump intakes or to complete dewatering of wells.

- Impact on wetlands

  Impacts to water levels in wetlands could result in degradation of habitat. Site-specific SEQRA reviews should be conducted for withdrawals within 500 feet of wetlands if pump test results show the withdrawal could have an influence on the wetland.

- Well Capability

  Test results will establish the maximum pumping rate of the well independent of impacts.

- Surface water impacts (passby flows)

  Passby flows are required to:

  - protect aquatic resources,
  - protect competing users,
  - protect instream flow uses,
  - limit adverse lowering of streamflow levels downstream of the point of withdrawal.

The Department proposes to impose requirements regarding passby flows as stated in this document. With those mitigation measures in place there would be no significant adverse impacts from water withdrawals made in connection with high-volume hydraulic fracturing and associated horizontal drilling.

7.1.1.6 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. New York State regulations do not currently 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 NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time. Accordingly, significant adverse cumulative impacts would be addressed by the NFRM described above because each operator of a permitted surface water withdrawal would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal.

7.1.2 Stormwater

The principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff is to require the development, implementation and maintenance of Comprehensive SWPPPs. SWPPPs address the often significant impacts of erosion, sedimentation, peak flow increase, contaminated discharge and nutrient pollution that is associated with industrial activity, including construction of well pads that would be required for high-volume hydraulic fracturing. This is commonly required through the administration of the Department's SPDES permits (individual or general) for stormwater runoff, which require operators to develop, implement and maintain up-to-date SWPPPs. To assist this effort, the Department 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. A successful Comprehensive SWPPP employs engineering concepts aimed at preventing erosion and maintaining post-development runoff characteristics in roughly the same manner as the pre-development condition. Many adverse impacts can 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 principle is to divert uncontaminated water away from excavated or disturbed areas. In addition, limiting the amount of soil exposed at any one time, stabilizing disturbed areas 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 described in the SWPPP.

A Comprehensive SWPPP that is well developed, implemented, maintained and adapted to changing circumstances in strict compliance with the Department's permit conditions and associated technical standards should 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 would require a SPDES permit to address stormwater runoff, erosion and sedimentation. The SPDES permit will address both the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during the production of natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP, and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued. The Department proposes to publish the proposed HVHF GP for public review and comment simultaneously with the formal public comment period on this document. A summary of the SPDES permit conditions follows.

Activities which are exposed to stormwater which will potentially take place during the development of a well pad may include:

- Well Drilling and Hydraulic Fracturing;
- Vehicle and Equipment Storage/Maintenance;
- Vehicle and Equipment Cleaning;
- Fueling;
- Material and Chemical Storage;
- Chemical Mixing, Material Handling, Loading/Unloading;
- Fuel/Chemical Storage Areas;
- Lumber Storage or Processing; and
- Cement Mixing.

Proposed required BMPs include, but not limited to, a combination of some or all of the following, or other equally protective practices:

- Identification of a spill response team and employee training on proper spill prevention and response techniques;
- Inspection and preventive maintenance protocols for the tank(s) and fueling area;

- Procedures for notifying appropriate authorities in the event of a spill or significant pit failure;
- Procedures for immediately stopping the source of the spill and containing the liquid until cleanup is complete;
- Ready availability of appropriate spill containment and clean-up materials and equipment, including oil-containment booms and absorbent material;
- Disposal of cleanup materials in the same manner as the spilled material;
- Use of dry cleanup methods and non-use of emulsifiers or dispersants;
- Protocols for checking/testing stormwater in containment area prior to discharge;
- Conducting tank filling operations under a roof or canopy where possible, with the covering extending beyond the spill containment pad to prevent rain from entering;
- Use of drip pans where leaks or spills could occur during tank filling operations and where making and breaking hose connections;
- Use of fueling hoses with check valves to prevent hose drainage after spilling;
- Use of spill and overflow protection devices;
- Use of diversion dikes, berms, curbing, grading or other equivalent measures to minimize or eliminate run-on into tank filling areas;
- Use of curbing or posts around the fuel tank to prevent collisions during vehicle ingress and egress;
- Availability of a manual shutoff valve on the fueling vehicle;
- Inspection and preventive maintenance protocols for the pit walls and liner;
- Procedures for immediately repairing the pit or liner and containing any released liquid until cleanup is complete;
- Location of additive containers and transport, mixing and pumping equipment as follows:
    - within secondary containment;
    - away from high traffic areas;
    - as far as is practical from surface waters;

- not in contact with soil or standing water; and
- product and hazard labels not exposed to weathering.

- Inspection and preventative maintenance protocols for containers, pumping systems and piping systems, including manned monitoring points during additive transfer, mixing and pumping activities;

- Protocols for ensuring that incompatible materials such as acids and bases are not held within the same containment area;

- Maintenance of a running inventory of additive products present and used on-site;

- 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;

- Location of tanks within secondary containment, away from high traffic areas and as far as is practical from surface waters; and

- Maintenance of a running inventory of flowback water and production brine recovered, present on site, and removed from the site.

As discussed below, the Department is proposing a method to terminate the application of the SPDES permit upon Partial Site Reclamation in the manner presented in the HVHF GP or otherwise by the Department. With the proposed SPDES permit conditions in place for construction activities and high-volume hydraulic fracturing, as well as permit conditions and/or regulations for gas production, any potential significant adverse impacts from stormwater discharges associated with high-volume hydraulic fracturing would be reduced for most locations.

7.1.2.1 Construction Activities

In order to facilitate the SPDES permitting process for activities addressed by this Supplement, the Department proposes to utilize the requirements in the SPDES General Permit for Stormwater Discharges from Construction Activities, GP-0-10-001 (Construction General Permit), effective January 29, 2010. A Construction SWPPP, meeting or exceeding the requirements of the Construction General Permit, would be required to be developed as a stand-alone document, but will also constitute part of the Comprehensive SWPPP. The Construction SWPPP would address all phases and elements of the construction activity, including all land clearing and access road and well pad construction. The Construction SWPPP would be required to be prepared in accordance with good engineering practices and Department's Construction General Permit.

A copy of the Construction SWPPP would be required to be kept on site and available to Department inspectors while SPDES permit coverage is in effect. Particular monitoring, inspections and recordkeeping requirements associated with the construction activity will be initiated upon commencement of construction activities and continue until completion of the construction project.

7.1.2.2 Industrial Activities

The SPDES permit will require development of a high-volume hydraulic fracturing SWPPP that will be a stand-alone document, but will also constitute part of the Comprehensive SWPPP. The high-volume hydraulic fracturing SWPPP would address potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges associated with high-volume hydraulic fracturing operations. The Department will require implementation of BMPs that are to be used to reduce the pollutants in stormwater discharges associated with high-volume hydraulic fracturing and to ensure compliance with the terms and conditions of the SPDES permit. Structural, non-structural and other BMPs would have to be considered in the high-volume hydraulic fracturing SWPPP. Structural BMPs include features such as dikes, swales, diversions, drains, traps, silt fences and vegetative buffers. Non-structural 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. Particular monitoring, inspections and recordkeeping associated with high-volume hydraulic fracturing would be initiated upon completion of the construction project and continue until coverage under the SPDES permit has been appropriately terminated. Monitoring, inspections and reporting for high-volume hydraulic fracturing will address visual monitoring, dry weather flow inspections, and benchmark monitoring and analysis. Sites active for less than one year would be required to satisfy all annual reporting requirements within the period of activity.

The proposed high-volume hydraulic fracturing SWPPP will apply during all hydraulic fracturing and flowback operations at a well pad and until such time as coverage under the HVHF GP is appropriately terminated. A copy of the high-volume hydraulic fracturing SWPPP must be kept on site and available to Department inspectors while SPDES permit coverage is in effect. SPDES permit coverage may be terminated upon completion of all drilling and hydraulic fracturing operations, fracturing flowback operations and partial site reclamation in a manner specified by the Department. Partial site reclamation has occurred when a Department inspector determines that drilling and fracturing equipment have been removed, the pit or pits used for those operations have been reclaimed, and surface disturbances or surface parking or storage structures not necessary for production activities have been re-graded and seeded, vegetation cover re-established, and post-construction management practices are fully operational. Operators may, however, elect to maintain coverage under the SPDES permit after partial site reclamation if they so choose.

7.1.2.3 Production Activities

As part of a permit and/or in regulation, the Department proposes to require the owner/operator of the high-volume hydraulic fracturing operation to address potential sources of pollution which may reasonably be expected to affect the quality of stormwater discharges associated with the production phase. The Department will require implementation of BMPs that are to be used to reduce the pollutants in stormwater discharges associated with the production of gas resulting from high-volume hydraulic fracturing and to ensure compliance with the terms and conditions of the appropriate permit and/or regulation. Structural, nonstructural and other BMPs will be incorporated into a permit and/or regulation.

Particular monitoring, inspections and recordkeeping associated with the high-volume hydraulic fracturing will be include in the permit and/or regulation and initiated once coverage under the SPDES permit has been appropriately terminated.

7.1.3 Surface Spills and Releases at the Well Pad

A combination of existing Department engineering controls and management practices, enhanced as necessary to address unique aspects of multi-well pad development and high-volume hydraulic fracturing, would be required in appropriate permits to prevent spills and mitigate adverse impacts from any that do occur. This would include disclosure to the Department of fracturing fluid constituents, so that the appropriate remediation measures can be taken if a spill occurs. 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:

- Fueling tank and tank refilling activities;
- Drilling fluids;
- Hydraulic fracturing additives and flowback water;
- Production brine;
- Materials and chemical storage;
- Chemical mixing, material handling, loading/unloading areas;
- Bulk chemical/fluid storage tanks;
- Equipment cleaning;
- On-site waste storage or disposal;
- Vehicle and equipment storage/maintenance areas;
- Piping/conveyances;
- Lumber storage and/or processing areas; and
- Cement mixing/concrete products manufacturing.

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;
- 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, the Department's Bulk Storage Programs and EPA 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;[437] and
  - Draft Department Program Policy DER-17.[438]
- SWPPP guidance compiled by the Department's Division of Water; The comprehensive Stormwater Pollution Prevent Plan (SWPPP) that would be required by the Department's proposed HVHF GP will include permit requirements for Good Housekeeping Procedures, Spill Reduction Measures and Structural Best Management Practices to minimize or eliminate pollutants in stormwater for all of the activities listed above;
- US Department of the Interior and US Department of Agriculture, 2007; and
- An industry BMP manual provided to the Department.

7.1.3.1 Fueling Tank and Tank Refilling Activities

The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank. Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements. The following measures are proposed to be required, via permit condition and/or regulation, to

[437] http://www.dec.ny.gov/docs/remediation_hudson_pdf/spots10.pdf.

[438] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf.

minimize or prevent spills. For all wells subject to the SGEIS, supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements with respect to fueling tanks and refilling activities:

a. Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks.

   The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and infiltration. Draft Department Program Policy DER-17[439] may be consulted for permeability criteria for dikes 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. Fueling tanks would not be positioned within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

c. Fueling tank filling operations would be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

d. Troughs, drip pads or drip pans would be required beneath the fill port of the fueling tank during filling operations if the fill port is not within the secondary containment.

7.1.3.2 Drilling Fluids

The 1992 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 1992 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

[439] http://www.dec.ny.gov/docs/remediation_hudson_pdf/der17.pdf.

> which should be factory seamed. Careful attention to sealing the seams is extremely important in preventing groundwater contamination; [440]*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.[441]

Existing 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."[442]

Within primary and principal aquifers, existing permit conditions require that if operations are suspended and the site is left unattended, pit fluids must be removed from the site immediately.[443] After the cessation of drilling and/or stimulation operations, pit fluids must be removed within seven days.

Recommended 1992 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, as would be the case for high-volume

[440] NYSDEC 1992, GEIS, p. 9-32.

[441] NYSDEC, 1992, GEIS p. FGEIS48.

[442] 6 NYCRR §554.(1)(c)(3).

[443] Freshwater Aquifer Supplementary Permit Conditions, www.dec.ny.gov/energy/42714.html.

hydraulic fracturing, would 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."[444] Specifications more stringent than those proposed in the 1992 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 would be provided by the requirement for a SWPPP and by measuring proposed setbacks from the edge of the well pad instead of from the well.

The following measures are proposed to be required to mitigate the potential for releases associated with any on-site reserve pit:

1) The EAF Addendum would require information about the planned location, construction and capacity of the reserve pit. The Department would not approve reserve pits on the filled portion of cut-and-fill sites; and

2) Supplementary permit conditions for multi-well pad high-volume hydraulic fracturing would include the following requirements:

    a. Diversion of surface water and stormwater runoff away from the pit;

    b. Flowback water would be prohibited from being directed to or stored in any on-site pit;

    c. Pit volume limit of 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land;

    d. Beveled walls (45 degrees or less) for pits constructed in unconsolidated materials;

    e. Sidewalls and bottoms free of objects capable of puncturing and ripping the liner;

    f. Sufficient slack in liner to accommodate stretching;

    g. Minimum 30-mil liner thickness;

    h. Liners installed and seamed in accordance with the manufacturer's specifications, and constructed, coated, or lined with materials that are chemically compatible with the substance (s) stored and the environment;

[444] GWPC, 2009 April, p. 29.

i. Freeboard monitoring and maintenance of 2 feet of freeboard at all times (except freshwater);

j. Fluids removed and pit inspected by a Department inspector prior to additional use if longer than a 45-day gap in use; and

k. Fluids removed and pit reclaimed within 45 days of completing drilling and stimulation operations at last well on pad.

As discussed in Section 7.1.9, the Department proposes, via permit condition and/or regulation, that, reserve pits would not be utilized for on-site management of drilling fluids and the cuttings entrained with the fluids when the cuttings are required to be disposed of at an off-site facility. Under circumstances which require the off-site disposal of cuttings, both the cuttings and all associated drilling fluids would be required to be managed on-site within a closed-loop tank system.

Chapter 5 discusses the required use of the blow-out prevention (BOP) system and Chapter 6 includes potential impacts that could occur as a result of a component failure of the BOP system or if the system is improperly operated. The Department proposes to require, via permit condition and/or regulation, the following requirements:

1. Individual crew member's responsibilities for blowout control would be posted in the doghouse or other appropriate location and each crew member would be made aware of such responsibilities prior to spud of any well being drilled or when another rig is moved on a previously spudded well and/or prior to the commencement of any rig, snubbing unit or coiled tubing unit performing completion work. During all drilling and/or completion operations when a BOP is installed, tested or in use, the operator or operator's designated representative would be present at the wellsite and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department (e.g., International Association of Drilling Contractors). Such certification would be available at the wellsite and provided to the Department upon request;

2. Appropriate pressure control procedures and equipment in proper working order would be employed while conducting drilling and/or completion operations including tripping, logging, running casing into the well, and drilling out solid-core stage plugs. Unless otherwise approved by the Department, a snubbing unit and/or coiled tubing unit with a BOP would be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs; and

3. Pressure testing of the blow-out preventer (BOP) and related equipment for any drilling and/or completion operation would be performed in accordance with the approved BOP use and test plan, and any deviation from the approved plan would be approved by the Department. Testing would be conducted in accordance with American Petroleum Institute (API) Recommended Practice (RP) 53, RP for Blowout Prevention Systems for Drilling Wells, or other procedures approved by the Department.

The aforementioned measures would reduce any significant adverse environmental impacts posed by drilling fluids associated with high-volume hydraulic fracturing.

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. Well pad setbacks from water resources described in Section 7.1.11 apply to all locations. Additional protection would be provided by the requirement to measure proposed setbacks from the edge of the well pad instead of from the wellbore. Additional mitigation measures would be implemented as follows to fully mitigate any potential significant adverse impacts from hydraulic fracturing additives:

1) Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.

   Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.

   The Department proposes to require, via permit condition and/or regulation, 1) removal of hydraulic fracturing additives from the site if the site will be unattended and 2) at least two vacuum trucks would be on standby at the wellsite during the pumping of hydraulic fracturing fluid;

2) As described in Part 8.2.1.2, the operator's permit application materials would document its evaluation of alternative additive products that may pose less risk to the environment, including water resources; and

3) Required disclosure to the Department of fracturing fluid additives would ensure that the appropriate steps could be taken if a spill or release did occur. (See Chapter 8 for a discussion of the specific additive information which would be required.)

7.1.3.4 Flowback Water

The 1992 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 1992 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 to require, via permit condition and/or regulation, that flowback water handled at the well pad be directed to and contained in covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department. 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 would be implemented as follows:

1) The EAF Addendum would require information about the number, individual and total capacity and location on the well pad of receiving tanks for flowback water;

2) Permit conditions for high-volume hydraulic fracturing would include the following requirements:

    a. Fluids would be removed if there will be a hiatus in site activity longer than 45 days;

    b. Fluids would be removed within 45 days of completing drilling and stimulation operations at last well on pad;

    c. Fluid transfer operations from tanks to tanker trucks would be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck;

    d. Secondary containment for flowback tanks is required; and

    e. At least two vacuum trucks would be on standby at the wellsite during the flowback phase.

7.1.3.5 Primary and Principal Aquifers

Based on the analysis contained in Section 6.1.3.4, the Department has determined that the activities associated with high-volume hydraulic fracturing pose a risk of causing significant adverse impacts to Primary Aquifers and, therefore, such operations may not be consistent with the long-term protection of Primary Aquifers. The Department finds that standard stormwater control and other mitigation measures may not fully mitigate the risk of potential significant adverse impacts on these water resources from spills or other releases that could occur in connection with high-volume hydraulic fracturing operations.

Therefore, the Department proposes to bar placement of high-volume hydraulic fracturing well pads over Primary Aquifers and an associated 500-foot buffer to provide an adequate margin of safety from the full range of high-volume hydraulic fracturing activities. As defined in TOGS 2.1.3, Primary Aquifers are currently extensively used by major municipalities as a source of drinking water. Contamination of a Primary Aquifer could render a large, concentrated population without drinking water. Replacing a drinking water source of this magnitude would be prohibitive because of exorbitant costs, difficulty in locating alternative water supply sources, and the extensive time needed to implement any alternatives. However, because the mitigation measures that would be imposed through permit conditions and/or regulations may prove effective for preventing uncontained, unmitigated releases that could contaminate Primary Aquifers, this bar will be re-evaluated two years after the commencement of issuance of well permits associated with high-volume hydraulic fracturing operations.

The Department further proposes to require a site-specific SEQRA review for placement of high-volume hydraulic fracturing well pads that are proposed to be located over Principal Aquifers or within a 500-foot buffer, as well as an individualized SPDES stormwater permit. As defined in TOGS 2.1.3 and explained in Chapters 2 and 6, Principal Aquifers are currently not intensively used by major municipalities as a source of drinking water, as compared to Primary Aquifers. However, contamination of a Principal Aquifer could still render a large population without water. Because mitigation measures that would be imposed through permit conditions and/or regulations may prove effective for preventing uncontained, unmitigated releases that could contaminate Principal Aquifers, this proposed requirement will be re-evaluated in two years after the commencement of issuance of well permits for high-volume hydraulic fracturing operations.

It is important to note that although the percentage of land in New York designated as a Primary and Principal Aquifer appears significant, due to the fact that wells can be drilled horizontally, well pads placed outside the boundary of a Primary and Principal Aquifer area may still allow for access to natural gas reserves underlying the significant majority of the area beneath Primary and Principal Aquifers. For example, assuming both a 500-foot buffer from the edge of a Primary and Principal Aquifer and the capacity to drill a 3,500-foot horizontal leg, and also assuming lease rights, surface access rights and lack of other siting restrictions, less than 1% of the area where the Marcellus Shale is deeper than 2,000 feet below ground surface and also beneath Primary or Principal Aquifers would be made at least potentially inaccessible for the extraction of natural gas by high-volume hydraulic fracturing.

Summary

The Department committed to evaluate the mitigation measures to determine whether they are sufficient to protect primary and principal aquifers, which are described in Chapters 2 and 6 of this Supplement and in the 1992 GEIS, the Department would implement the following restrictions until at least two years after issuance of the first permit for high-volume hydraulic fracturing:

1) No well pads would be approved within 500 feet of primary aquifers; and

2) A site-specific SEQRA review and determination of significance, and a site-specific SPDES permit, would be required for any proposed well pad within 500 feet of a principal aquifer.

Two years after issuance of the first permit for high-volume hydraulic fracturing, the Department would re-evaluate the need for these restrictions based on experience with high-volume hydraulic fracturing outside of these restricted areas.

7.1.4 Potential 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 would remain in use, and would be enhanced by 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,[445] the Department proposes to require the following measures associated with well drilling and construction in order to prevent potential groundwater impacts from these activities:

- 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 in the annular space around the intermediate casing;
    - Adequacy of cement on production casing to prevent upward migration of fluids; including gas, during hydraulic fracturing and production conditions;
    - Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings; and
    - The opportunity for state regulators to witness cementing operations; and
- Prevention of pressure build-up at the surface casing seat and in the annular space between the surface casing and intermediate 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);
- The Department's existing supplementary freshwater aquifer permit conditions (Appendix 9);

[445] GWPC, 2009 May.

- 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);

- Commissioner's Decision, 1985, regarding well casing cement and the requirement to maintain an open annulus to prevent gas migration into aquifers;

- API, regarding:

  - Specification 5CT, Specifications for Casing and Tubing (April 2002);

  - Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

  - RP 10D-2, RP for Centralizer Placement and Stop Collar Testing (August 2004);

  - Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum);

  - Guidance Document, HF1, Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines (October 2009); and

  - RP 65 – Part 2, Isolating Potential Flow Zones During Well Construction (May 2010).

- Pennsylvania Environmental Quality Board, Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells, Pennsylvania Bulletin, Vol. 41, No. 6 (February 5, 2011);

- 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;[446]

- NYSDOH recommendations relative to private water well testing dated July 21, 2009, based on review of fracturing fluid constituents and flowback characteristics;

[446] http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs3_water_quality.htm, accessed 9/16/09.

- 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.

7.1.4.1 Private Water Well Testing

The Department proposes to require, via permit condition, that the operator, at its own expense, sample and test all 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. The Department would require that results of each test be provided to the property owner within 30 days of the operator's receipt of laboratory results. The Department would further require that the data be available to the Department and local health department upon request for complaint investigation purposes.

Schedule

Testing before drilling is recommended as a mitigation measure related to the potential for groundwater contamination because it 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 would 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 to require, via permit condition 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, 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 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 or for other reasonable cause.

Parameters

The NYSDOH recommends testing for the analytes listed in Table 7.3 to aid with determining whether gas drilling may have had an impact on the quality or quantity of a well. This analysis is not intended to constitute a comprehensive evaluation. In the event that a potential impact is determined, additional investigation (e.g., isotopic analysis of methane to determine source or site-specific chemical analysis) may be necessary.

Table 7.3 - NYSDOH Water Well Testing Recommendations
(Revised July 2011 to reflect more recent recommendations from NYSDOH)

Parameter	Notes
Barium	Barium (barite) is a principal component of many drilling muds. In the event that barite is not used in the drilling mud, a substitution should be made for a component that is present in the drilling mud.
Chloride	A measure of chloride anions in water. Chlorides and other salts are naturally occurring and can be found in many different geologic zones, but deep groundwater typically contains high levels of chloride. Flowback water contains high levels of chlorides. Therefore, an increase in chlorides may be an indication that drilling has allowed communication between geologic zones and/or flowback water has contaminated an aquifer.
Conductivity	A measure of the ability of water to pass an electrical current. Conductivity in water is affected by the presence of inorganic dissolved solids such as chloride, nitrate, sulfate, and phosphate anions (ions that carry a negative charge) or sodium, magnesium, calcium, iron and aluminum cations (ions that carry a positive charge). Organic compounds like oil, phenol, alcohol and sugar do not conduct electrical current very well and therefore have a low conductivity when in water. A change in water quality as a result of drilling is expected to affect the conductivity.
Gross alpha/beta	Radioactivity is typically elevated in shale relative to other rock types and the Marcellus Shale is especially enriched. Drilling and production of shale may have the ability to mobilize radioactivity towards the surface where it could either concentrate or infiltrate aquifers. These Gross analyses are screening values for defining when to perform more detailed analyses.
Iron	Iron is commonly found in many aquifers and may be mobilized during initial drilling activities.
Manganese	Manganese is commonly found in many deep and shallow aquifers and may be mobilized during initial drilling activities.
Dissolved methane & ethane	Occurs naturally in many aquifers but may also migrate into aquifers as a product of drilling and production. Additional analysis may be necessary to determine the source and/or percentages of dissolved gasses.
pH	A measure of how acidic or basic water is. pH is sensitive to small changes in water chemistry such as those that may result from natural gas drilling.
Sodium	Sodium is naturally occurring and commonly found in most water. However, sodium is found in high concentrations in deep shale production brines and gas wells.
Total dissolved solids (TDS)	A measure of all dissolved organic and inorganic species in water. TDS is useful as an indicator of aesthetic characteristics of drinking water and as an aggregate indicator of the presence of a broad array of chemical contaminants. An increase in TDS may be indicative of drilling operations having introduced contaminants into the water supply.
Static water level	Static water level is the level of the water in the well during normal conditions prior to any pumping. This is a measure of the amount of water in the aquifer. 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.
Volatile organic compounds (VOCs), specifically BTEX	VOCs encompass a number of compounds that are expected to be used extensively during surface operations and would account for water supplies potentially being affected by spills, leaking pits, or other unforeseen incidents. Additionally, certain VOCs are known to exist in shale and are expected to be a contaminant of concern in the event that flowback waters or production brines migrate into an aquifer.

Sampling Protocol

The Department proposes to require that water samples to be collected by a qualified professional and analyzed utilizing a NYSDOH ELAP approved laboratory,[447] including the use of proper sampling and laboratory protocol, in addition to the use of proper sample containers, preservation methods, holding times, chain of custody, analytical methods, and laboratory QA/QC.

The water samples would be representative of the aquifer being produced by the well. Therefore, the well pump should be allowed to run for at least 5 minutes prior to sample collection. The sample should be collected prior to any in home water treatment that may be present. If this is not feasible, the type of treatment that is present on the well survey should be noted. The samples should be collected in appropriate containers, refrigerated, and transported to the laboratory for analysis.

Recommended Sampling Procedure for Water Supply Wells

- Select an indoor, leak-free, cold water faucet from which to collect the sample. If treatment (softener, filter, RO, etc.) exists the sample should be collected from an untreated location or the treatment should be bypassed;
- Remove the faucet's aerator or strainer, if one is present;
- Disinfect the faucet by cleaning and flaming the inside of the faucet;
- Let cold water run for 5 minutes;
- Reduce water flow to a stream of water the size of a pencil or smaller;
- Fill sample bottles per method specifications, making sure not the touch the inside of the bottle or cap; and
- Cap bottles, refrigerate, and transport to the laboratory for analysis.

[447] http://www.wadsworth.org/labcert/elap/elap.html, accessed 9/16/09.

Complaints

As noted in the 1992 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.[448] *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.[449]

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 the Department 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 continue following the aforementioned procedure statewide. Complaints would be referred to the county health department, who would refer them back to the Department 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.

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 the Department and the county health department. Mineral Resources staff would 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

[448] NYSDEC, 1992, GEIS, pp. 15-4 et seq.

[449] NYSDEC, 1992, GEIS, p. 15-5.

would 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;
- Fracturing equipment failure;
- Observed leaks in surface equipment onto the ground, into stormwater runoff or into a surface water body;
- 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; and

The Department and the county health department would 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, would be considered in determining the proper course of action with respect to well pad activities. Sub-section 8.2.3 describes the Department's enforcement authority and the enforcement mechanisms available to the Department.

7.1.4.2 Sufficiency of As-Built Wellbore Construction

Wellbore construction is addressed by the existing 1992 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. Further, recent Marcellus Shale well drilling and completion experience and associated problems in other states were analyzed and considered.

Surface Casing

As defined in regulations, the purpose of surface casing is to protect potable fresh water.[450] For oil and gas regulatory purposes, potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm of total dissolved solids.[451] 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 geologic or hydrogeologic reports, and information from the sources listed in Section 7.1.11.1. When information is not available, a depth of 850 feet to the base of potable groundwater is a commonly-used and practical generalization.

Current casing and cementing practices attached as conditions to all oil and gas permits require that:

- 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 psi, or used casing that is pressure tested before drilling ahead after cementing; welded pipe must also be pressure tested.

The Department proposes to require, via permit condition and/or regulation, the submission of a *Pre-Frac Checklist and Certification Form* (pre-frac form) to the Department at least 3 days

[450] 6 NYCRR §550.3(au).

[451] 6 NYCRR §550.3(ai).

prior to commencement of high-volume hydraulic fracturing operations. Regarding the surface casing hole, the pre-frac form would:

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 would not be authorized to proceed without the above information and certification.

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 psi (e.g., performance chart).

All of the above requirements would remain in effect, and the Department would require the following additional requirements via permit condition and/or regulation:

1) The pre-frac form would be required as described above;

2) Cement would be required to conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry would be required to be prepared to minimize its free water content in accordance with the same API specification and it would be required to contain a gas-block additive; and

3) A minimum WOC (wait on cement) time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a

> waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.

Intermediate Casing

Intermediate casing is run in a well after the surface casing but before production hole is drilled. Fully cemented intermediate casing can be necessary in some wells to prevent possible pressurization of the surface casing seat, and to effectively seal the hole below the surface casing to prevent communication between separate hydrocarbon-bearing strata and between hydrocarbon and water-bearing strata. The primary uses of intermediate casing are to 1) provide a means of controlling formation pressures and fluids below the surface casing, 2) seal off problematic zones prior to drilling the production hole and 3) ensure a casing seat of sufficient fracture strength for well control purposes. The intermediate casing's design and setting depth is typically based on various factors including anticipated or encountered geologic characteristics, wellbore conditions and the anticipated formation pressure at total depth of the well. Factors can also include the setting depth of the surface casing, occurrence of shallow gas or flows in the open hole, mud weights used to drill below intermediate casing, and well-control and safety considerations.

Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis. The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required. However, the Department may grant an exception to the intermediate casing requirement when technically justified. A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.

Intermediate and Production Casing Cement

Current casing and cementing practices set requirements for production casing cement and state that intermediate casing cement requirements would 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 logs 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 calculated (e.g., performance chart) compressive strength of 500 psi is achieved before the casing is disturbed in any way.

The above requirements will remain in effect. In addition, the Department proposes to require, via permit condition and/or regulation, the following additional requirements for high-volume hydraulic fracturing:

1) The pre-frac form would be required as described above;
2) The setting depth of the intermediate casing would consider the cementing requirements for the intermediate casing and the production casing as noted below;
3) Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice;
4) Production casing cement would be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth (TVD). If intermediate casing

installation is waived by the Department, the production casing would be cemented to the surface;

5) Cement would conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry would be prepared to minimize its free water content in accordance with the same API specification and it would contain a gas-block additive;

6) A minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig;

7) The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively; and

8) The internal pressure test of the production string, prior to hydraulic fracturing, may not commence for at least 7 days after the primary cementing operations are completed on this casing string to help prevent the formation of a micro-annulus.

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.

The above requirements will remain in effect. In addition, the Department proposes to require, via permit condition and/or regulation, additional requirements for high-volume hydraulic fracturing:

1) At least two centralizers, one in the middle and top of the first joint of casing, would be installed on the surface and intermediate casing strings, and all bow-spring style

centralizers used on all strings would conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).

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 when welded connections or used casing is run. 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. Supplementary Permit Conditions for high-volume hydraulic fracturing require notification prior to surface, intermediate and production 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 would 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 Setback from FAD Watersheds

Based on the analysis set forth in Section 6.1.5, the Department concludes that high-volume hydraulic fracturing within the NYC and Syracuse watersheds poses the risk of causing significant adverse impacts to these irreplaceable water supplies. The potential economic consequence of such impacts – loss of Filtration Avoidance – are substantial. The Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing. Even with such controls in place, the risk of spills and other unplanned events resulting in the discharge of pollutants associated with high-volume hydraulic fracturing operations, even if relatively remote, would have significant consequences in these unfiltered water supplies. In addition, the increased industrial activity associated with well pad development, road construction and other activities associated with high-volume hydraulic fracturing is not consistent with the long-term protection of the NYC and Syracuse unfiltered surface drinking water supplies. Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000-foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality. See, e.g., National Research Council Watershed Management for Potable Water Supply: Assessing the NYC Strategy at 97-98 (2000); American Water Works Association, *State Source Water Protection Statement of Principles,* AWWA Mainstream (1997).

7.1.6 Hydraulic Fracturing Procedure

As detailed in this document, potential impacts to ground water from the high-volume hydraulic fracturing procedure itself are, in most cases, not anticipated. To the extent that any impacts may occur, the risks have been reduced by all of the proposed mitigation measures outlined above that the Department proposes to require as permit conditions and/or regulations for high-volume hydraulic fracturing. These include:

- Requirement for private water well testing;
- Pit construction and liner specifications for well pad reserve pits;
- Requirement that covered watertight tanks be used to contain flowback water on site;
- Appropriate secondary containment measures;
- Removal of fluids within specified time frames;
- Requirement that a Department-approved BOP Use and Test Plan be followed during well drilling and/or completion operations;
- Requirement that a snubbing unit and/or coiled tubing unit with a BOP be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs;

- Requirement that appropriate pressure-control procedures and equipment be used, and fracturing equipment that is pressure tested with fresh water, mud or brine ahead of pumping the hydraulic fracturing fluid;

- Requirement for notification to the Department prior to cementing surface, intermediate, and production casing;

- Requirements for cement to surface on the surface and intermediate casing strings and production casing cement tied into the intermediate casing, and a radial cement bond evaluation log or other evaluation approved by the Department on the intermediate and production casing strings;

- Requirement for the submittal of a fracturing treatment plan (as part of the pre-frac form) which includes a profile of the anticipated pressures and water volume for pumping the first stage, a description of the planned treatment interval (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)), the total number of stages and total volume of water for hydraulic fracturing operations;

- Use of the pre-frac form to certify wellbore integrity prior to fracturing;

- Pre-fracturing pressure testing of casing (if a fracturing string is not used) from surface to top of treatment interval;

- Requirement that, prior to spudding the first well on a well pad, a non-routine incident plan is in place to address potential threats to public health and the environment. The plan would include detailed descriptions of notification, reporting, and remedial measures to ensure that any non-routine incident is addressed as quickly and as completely as possible; and

- Disclosure to the Department of fracturing fluid additives so that appropriate remedial actions can be taken in response to any spill or release.

The Department proposes to require as standard permit conditions non-routine incident handling requirements to ensure that any potential environmental or public health issues are identified, reported, and remedied as expeditiously as possible. Non-routine incidents would be identified as soon as possible, and verbal notification to the department would be made within two hours of its discovery or known occurrence. Non-routine incidents may include, but are not limited to: casing, drill pipe or hydraulic fracturing equipment failures; cement failures; fishing jobs; fires; seepages; blowouts; surface chemical spills; observed leaks in surface equipment; observed pit liner failures; surface effects at previously plugged or other wells; observed effects at water wells or at the surface; complaints of water well contamination; anomalous pressure and/or flow conditions indicated or occurring during hydraulic fracturing operations; or other potentially polluting non-routine incidents or incidents that may affect the health, safety, welfare, or property of any person. If hydraulic fracturing activities are suspended pending the satisfactory completion of non-routine incident reporting and remediation, the operator would be required to receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

To help reduce the risk that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment. If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations.

The proposed permit conditions would also include a requirement to monitor flowback rates in addition to daily and total flowback volumes. These flowback data would be required to be documented on the Well Drilling and Completion Report. Though flowback rates (and volumes) will likely vary based on differing well-specific conditions, an analysis of flowback rates may provide an indication of future flowback rates.

As explained in Section 6.1.5.2, the conclusion that harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone. The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing. As stated in Section 8.4.1.1, 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 any part of the proposed length of the wellbore is shallower than 2,000 feet below the ground surface; and

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

Review would focus on local topographic, geologic, and hydrogeologic conditions, along with proposed fracturing procedures to determine the potential for a significant adverse impact to fresh groundwater. The need for a site-specific SEIS would be determined based upon the outcome of the review.

7.1.7 Waste Transport

7.1.7.1 Drilling and Production Waste Tracking Form

Prior to well permit issuance, the applicant would be required to provide a fluid disposal plan as required by 6 NYCRR § 554.1(c)(1). Waste transport is an integral part of that plan and transportation tracking helps to ensure that fluid wastes are disposed of properly. Because of the number of wells that may be drilled and the current limited disposal options, as well the anticipated volume of flowback water, the paucity of reliable data regarding flowback water and production brine composition from New York operations, and NORM concerns, the Department proposes to require via permit condition and/or regulation 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 would be similar to what is presently required for medical waste.[452] The form would be required regardless of whether waste is taken to a treatment facility, disposal well, another well pad, a landfill, or elsewhere. Flowback water transport may be reduced by treatment and reuse on the same pad for hydraulic fracturing. The *Drilling and Production Waste Tracking Form* would also be used to track the transport of production brine from wells covered under the SGEIS.

7.1.7.2 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.

Production Brine

The notification described above informed Part 364 haulers that any entity applying for a Part 364 permit or permit modification to use production brine for road spreading must submit a petition for a BUD to the Department. However, the data available to date associated with NORM concentrations in Marcellus Shale production brine is insufficient to allow road spreading under a BUD. As more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department.

For production brines that are intended for use on roads, the BUD and Part 364 permit would be issued by the Department prior to the removal of any production brine from the well site. As set forth in the notification, a BUD petition would include analytical results from an ELAP-approved laboratory of a representative sample for the following parameters: NORM, calcium, sodium, chloride, magnesium, TDS, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Dependent upon the analytical results, the Department may require additional analyses. Evaluations of BUD petitions would include case-by-case

452 http://www.dec.ny.gov/docs/materials_minerals_pdf/medwste.pdf.

assessments of potential impacts, and would establish limits on volume and frequency of application.

7.1.7.3 Flowback Water Piping

Flowback water piping and conveyances between well pads and flowback water storage tanks would be described in the fluid disposal plan required by 6 NYCRR §554.1(c)(1) and the proposed GP. The fluid disposal plan would demonstrate that pipelines and conveyances would 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.

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.[453]

The specific provisions of Subpart 360-6 Liquid Storage would provide the overall requirements for tanks, describing the minimum operational, monitoring and closure requirements. These provisions would cross-reference other applicable provisions of Part 360 which more specifically address system design, materials, quality assurance and certification requirements that likewise would be applicable to the flowback water containment systems discussed in the SGEIS.

7.1.7.4 Use of Tanks Instead of Impoundments for Centralized Flowback Water Storage

As previously noted, centralized flowback water surface impoundments are not covered under the SGEIS and the Department proposes that such require a site-specific environmental assessment and SEQRA determination of significance. Nevertheless, above ground storage tanks have 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 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

[453] 6 NYCRR Part 360 regulations: http://www.dec.ny.gov/regs/2491.html.

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.

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 Discharge Permits

SPDES Discharge Permits - The federal Clean Water Act authorized the development of the *National Pollutant Discharge Elimination System* (NPDES) for implementing the requirements for all discharges to surface waters of the United States. The Department was subsequently charged, pursuant to the ECL, to develop and administer the state's program for meeting the requirements of NPDES. This program, which is authorized by the EPA, is referred to as the *State Pollutant Discharge Elimination System* (SPDES).

Regulation of discharges of pollutants to waters of the state, both surface and groundwaters, is authorized by Article 17 of the ECL. Specific controls on point source discharges are authorized by Article 17, Title 8 of the ECL. New York's SPDES program is more stringent than the federal NPDES program in that the SPDES program also regulates discharges to groundwater. The minimum threshold for applicability of SPDES to groundwater discharges is 1,000 gpd for sanitary wastewater, while discharges which include any industrial wastewater have no minimum threshold. The NYSDOH regulates discharges of less than 1,000 gpd consisting of only sanitary wastewater. The Department is authorized to issue SPDES permits for groundwater discharges for a maximum period of 10 years; permits for discharges to surface waters are issued for a maximum of 5 years.

Administration of the SPDES program is accomplished through the issuance of wastewater discharge permits, including both *individual* permits and *general* permits. Individual SPDES permits are issued to cover a single facility in one location possessing unique discharge characteristics and other factors. General SPDES permits are issued to cover a category of discharges involving the same or similar types of operations; discharge the same types of pollutants; require the same effluent limitations or operating conditions; require the same or similar monitoring; and do not have a significant impact on the environment, either individually or cumulatively, when carried out in conformance with permit provisions.

The Department is vested with the authority pursuant to state and federal law to enforce the SPDES permit requirements. The primary objective of the SPDES compliance and enforcement program is to protect water quality by ensuring that all point sources of pollution obtain a SPDES permit and comply with all terms and conditions of the permit.

The Department would employ any available compliance mechanisms that may be necessary, including formal enforcement, to attain the goal of SPDES permit compliance.

Flowback water and production brine are considered industrial wastewater. Wastewater is generated by many water users and industries. The SPDES program controls point source discharges to ground waters and surface waters. The Department proposes to require, through the well permitting process, that the permittee demonstrate prior to issuance of the drilling permit that any wastewater treatment facility proposed for disposal flowback water and production brine has the necessary treatment capacity. Furthermore, the Department proposes to continue requiring that once high-volume hydraulic fracturing operations have ceased and the gas well(s) are in the production phase, that the permittee properly collect and dispose of all production fluids generated at the site.

7.1.8.1 Treatment Facilities

SPDES permits are issued to wastewater dischargers, including treatment facilities such as POTWs operated by municipalities. SPDES permits include specific discharge limitations and monitoring requirements. The effluent limitations are typically 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 Department's DOW shares pretreatment program oversight (approval authority) responsibility with the EPA. Indirect discharges to POTWs are regulated by 6 NYCRR §750-2.9(b), National Pretreatment Standards, which incorporates by reference the requirements set forth under 40 CFR Part 403, "General Pretreatment Regulations for Existing and New Sources of Pollution." In accordance with DOW's TOGS 1.3.8, 6 NYCRR §750-2.9, 40 CFR Part 403, and 40 CFR 122.42, New York State POTW permittees with industrial pretreatment or mini-pretreatment programs are required to notify the Department of new discharges or substantial changes in the volume or character of pollutants discharged to the permitted POTW. The Department 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 or any other wastewater treatment plant with approved pretreatment or mini-pretreatment programs, as noted above, and an approved headworks analysis for this wastewater source in accordance with 40 CFR Part 403 and DOW's TOGS 1.3.8 and as required by the POTW's SPDES permit that includes appropriate monitoring and effluent limits for this wastewater source. The SPDES permit for the POTW would include specific discharge limitations and monitoring requirements, including routine reporting of monitoring results, tracking of these results by the Department, and a well established compliance program to deal with permit violations.

The Department's procedures for POTW acceptance of high-volume hydraulic fracturing wastewater discharges are detailed in Appendix 22 of this Supplement. Discharges that follow these procedures would provide effective mitigation of significant adverse impacts.

Private Wastewater 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. The permittee would apply for SPDES permit coverage 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.

Private treatment systems, which are designed, constructed, and approved to treat the parameters specific to high-volume hydraulic fracturing wastewater, including processes as discussed in Section 5.12 (Flowback Water Treatment, Recycling and Reuse), may be more effective than POTWs for the treatment, disposal, and potential reuse of this source of wastewater because they can be designed and optimized to remove the parameters specific to this source of wastewater.

As noted in Chapter 5 of this revised draft SGEIS, onsite treatment of flowback water for purposes of reuse is currently being used in Pennsylvania and other states. The treated water is blended with fresh water at the well, generally, and reused for hydraulic fracturing with the treatment residue hauled off-site. These types of facilities do not require a SPDES permit unless the discharge of wastewater is planned. The use of on-site treatment and reuse facilities reduces the demand for fresh water and provides effective mitigation of potential adverse impacts.

7.1.8.2 Disposal Wells

Because of the 1992 GEIS 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. The permittee would apply for and receive coverage under the EPA UIC program prior to applying for a SPDES permit for discharge using Form NY-2C, available on the Department's website. The characterization and SPDES permit application process for disposal wells is similar to that for private treatment facilities.

The Department may propose monitoring requirements and/or discharge limits in the SPDES permit in addition to any requirements included in the required EPA UIC permit. These would 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 would consider the following topics:

- Distance to drinking water supplies or sources, surface water bodies 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 DOW TOGS 1.1.1; and
- Potential requirement for upgradient and downgradient monitoring wells installed in the deepest identified GA or GSA potable water aquifer.

New York State currently has six permitted underground disposal wells, three of which are used to dispose of brine produced with oil and /or gas. However, these wells are privately owned and currently are approved to inject only their own brine. Use of an existing permitted underground disposal well would require a modification of the existing UIC and SPDES permits for the existing wells to accept flowback.

The Department notes that potential impacts as described in Chapter 6 of this revised draft SGEIS have occurred in other states, and remain a concern. With the above mitigation measures in place, combined with permit monitoring and oversight, significant impacts from waste transport and disposal in connection with high-volume hydraulic fracturing wastewater would be reduced.

7.1.9 Solids Disposal

Cuttings may be managed within a closed-loop tank system or within the lined reserve pit. If cuttings are contained within 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 contaminated with oil-based or polymer-based mud could not be buried on site; they would be managed in a closed-loop tank system and removed from the site for disposal in a Part 360 solid waste facility. Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing require consultation with the Department's Division of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives. Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit.

As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral),[454] there exists the potential that cuttings derived from this interval and placed in reserve pits may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD). A site-specific ARD-mitigation plan would be required to be prepared and followed by the operator for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings. The ARD-mitigation plan would be designed to neutralize acid drainage through the emplacement of basic carbonate materials (e.g., waste lime or limestone cuttings) prior to on-site burial. The pyritic drill cuttings and the carbonate materials would be mixed thoroughly and compacted prior to reclamation of the pit area. This method was demonstrated to be effective in an ARD-abatement

[454] Engelder and Lash, 2008.

project jointly conducted by Penn DOT and PADEP during construction of U.S. Route 22 near Lewiston PA in 2004.[455]

Alternatively, if the operator elects or is required (for reasons related to drilling fluid composition, as previously discussed) to utilize an off-site disposal facility for disposal of cuttings from horizontal drilling in the Marcellus Shale, then no ARD-mitigation plan is required. In such instances however, supplementary permit conditions require that these cuttings be managed and contained on-site within a closed-loop tank system rather than within a reserve pit, prior to removal for off-site disposal.

Annular disposal of drill cuttings has also been proposed; however, this is not an acceptable practice in New York and is prohibited by the high-volume hydraulic fracturing Supplementary Permit Conditions.

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.

7.1.10 Protecting NYC's Subsurface Water Supply Infrastructure

The advent, in the late 1990s and early 2000s, of geothermal well drilling – also regulated under ECL 23 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 NYC 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 NYC, 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.

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

455 Smith et al. 2006.

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 would 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.[456]

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 NYC's underground water tunnels and aqueducts.[457] 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 1992 GEIS criteria for requiring supplemental environmental review for proposed well locations within 1,000 feet of municipal water supply wells.

To mitigate impacts to NYC's subsurface water supply infrastructure, Department staff would continue to follow the above protocol for any proposed ECL 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 Setbacks

Setbacks provide a margin of safety should the operational mitigation measures fail, and are therefore a useful risk management tool. The NYSDOH recognizes separation distances, or setbacks, as a crucial element of protecting water resources against contamination.[458] While the

456 Sanford, K.F., 2007.

457 6 NYCRR Part 552.4 Regulations: http://www.dec.ny.gov/regs/4465.html

458 http://www.health.state.ny.us/environmental/water/drinking/part5/append5b/fs1_additional_measures.htm, viewed 8/26/09.

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 help 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 in DMN and DOW:

- The 1992 GEIS and its Findings;
- NYSDOH's required water well separation distances, set forth in Appendix 5-B of the State Sanitary Code.[459] Although sites specifically related to natural gas development and production are not explicitly listed among the potential contaminant sources addressed by Appendix 5-B, NYSDOH 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;[460]
- Results and discussion provided by Alpha to NYSERDA regarding Alpha's review of the rules and regulations pertaining to protection of water supplies in NYC's Watershed.[461] Again, although natural gas development activities are not specifically addressed, and this SGEIS does not cover high-volume hydraulic fracturing in the NYC or Syracuse watersheds, Alpha identified activities which could be considered analogous to aspects of high-volume hydraulic fracturing, including:
    - Hazardous materials storage;
    - Radioactive waste disposal;
    - Storage of petroleum products;
    - Impervious surfaces;

459 http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

460 Alpha, 2009, Tables 2.1 - 2.10.

461 Alpha, 2009, p. 94.

- Stormwater pollution 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;
  - Disposal of radioactive waste by burial in soil; and
  - Direct discharge of polluted liquid to the ground or a water body.

7.1.11.1 Setbacks from Groundwater Resources

The following discussion pertains to the lateral distance, measured at the surface, to a water supply or spring from the closest edge of the well pad.

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 location of the aquifer penetration at each well corresponds to the well's location on the ground surface. 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 would 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 setback discussed herein threshold for public water supply wells is properly applied. The operator would be required to identify the wells and springs, and provide available information about their depth, completed interval and use. Use information would 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
- Department'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 would 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 would be required to amend its EAF Addendum accordingly.

The EAF Addendum for high-volume hydraulic fracturing would also require well operators to identify any wells listed within the Department's Oil & Gas Database[462] within a) the spacing unit of the proposed well and b) within 1 mile (5,280 feet) of the proposed well location. For each well identified, operators would be required to provide information regarding the distance from the surface location of the existing well to the surface location of the proposed well, as well as information regarding the quantity and type of any freshwater, brine, oil or gas encountered during the drilling of the well, as recorded on the Department's Well Drilling and Completion Report.

This requirement would help to ensure that available information on nearby wells is considered by the operator while designing the proposed wellbore. Additionally, this information can be

[462] The Department's Oil & Gas Database contains information on more than 35,000 oil, gas, storage, solution salt, stratigraphic, and geothermal wells categorized under ECL 23 as Regulated Wells. The Oil & Gas database can be accessed on the Department's website at http://www.dec.ny.gov/cfmx/extapps/GasOil/.

used by Department staff to review any necessary Department well files to ensure that the operator’s proposed wellbore design is sufficient to protect ground water resources.

Public Water Supplies and Primary and Principal Aquifers

The Department’s 1992 GEIS concluded 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 SEIS to analyze groundwater hydrology, potential impacts and propose mitigation measures. The 1992 GEIS also found that 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 1992 GEIS provides the discretion to apply the same process to other public water supply wells.

For multi-well pads and high-volume hydraulic fracturing, the Department proposes that site disturbance associated with such operations be prohibited within 2,000 feet of any public (municipal or otherwise) water supply well, reservoirs, natural lake or man-made impoundments (except engineered impoundments constructed for fresh water storage associated with fracturing operations), and river or stream intake, in order to safeguard against significant adverse impacts due to surface spills and leaks on the well pad that could impact the groundwater supply. As noted, these setbacks would be measured from the closest edge of the well pad. The Department will re-evaluate the necessity of this approach after three years of experience issuing permits in areas outside of the 2,000-foot boundary.

In addition, as stated in sub-section 7.1.3, the Department proposes that for at least two years the surface disturbance associated with high-volume hydraulic fracturing, including well pad and associated road construction and operation, be prohibited within 500 feet of primary aquifers. The Department further proposes that a site-specific SEQRA review be required for high-volume hydraulic fracturing projects at any proposed well pad within or within 500 feet of a Principal Aquifer. As noted, these setbacks would be measured from the closest edge of the well pad. The Department will re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of these restricted 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, would be measured from the edge of the well pad.

As stated above, uncovered 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.[463] 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.[464] Handling and mixing of hydraulic fracturing additives onsite is comparable to "fertilizer and/or pesticide mixing and/or clean up areas," which require a 150-foot distance from water wells.[465]

The Department proposes that it will not issue well permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic-supply spring, unless waived by the landowner.

7.1.11.2 Setbacks from Other 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 evaporation or soil adsorption 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."[466] 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.

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[463] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[464] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[465] http://www.health.state.ny.us/environmental/water/drinking/part5/appendix5b.htm#table1, viewed 8/26/09.

[466] 6 NYCRR §553.2.

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 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 reduce the risk of surface water contamination resulting from well pad operations include the following:

- Required stormwater permit coverage, including a 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 closed-loop tank systems be used instead of reserve pits for any horizontal drilling in the Marcellus Shale without an ARD- mitigation plan for on-site burial of cuttings and for any drilling requiring cuttings to be disposed of off-site;
    - 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, mud or brine 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.]; and
- The Department’s existing requirement for a Freshwater Wetlands Permit in wetland or 100-foot buffer zone.

With respect to surface municipal supplies, the 1992 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 water bodies 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 addressed in some 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 to surface-water bodies. 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.[467] 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.[468]

Many local Watershed Rules and Regulations require smaller setbacks from watercourses, as specifically defined within the watershed, than from reservoirs.

Based on the above information and mitigating factors, the Department proposes that site-specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.

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467 Alpha, 2009, pp. 41-45.

468 http://cogcc.state.co.us/RR_Docs_new/rules/300series.pdf, viewed 8/26/09.

7.2 Protecting Floodplains

The Department proposes to require, through permit condition and/or regulation, that high-volume hydraulic fracturing not be permitted within 100-year floodplains in order to mitigate significant adverse impacts from such operations if located within 100-year floodplains.

7.3 Protecting Freshwater Wetlands

Section 2.3.10 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 1992 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 1992 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, fueling tanks not be placed within 500 feet of a wetland (Section 7.1.3.1); and
- Requirement for secondary containment consistent with the Department's SPOTS 10 for any fueling tank, regardless of size (Section 7.1.3.1).

7.4 Mitigating Potential Significant Impacts on Ecosystems and Wildlife

Fragmentation of habitat, potential transfer of invasive species, and potential impacts to endangered and threatened species are identified in Chapter 6 as potential significant adverse ecosystem and wildlife impacts specifically related to high-volume hydraulic fracturing that are not addressed by the 1992 GEIS. The following text identifies mitigation measures to address significant impacts of fragmentation of habitat, potential transfer of invasive species, and endangered and threatened species, as well as the use of certain State-owned land.

7.4.1 Protecting Terrestrial Habitats and Wildlife

Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable. In particular, the most significant potential wildlife impact associated with high-volume hydraulic fracturing is fragmentation of rare interior forest and grassland habitats and the resulting impacts to the species that depend on those habitats. However, the following specific mitigation measures would prevent some impacts, minimize others, and provide valuable information for better understanding the impacts of habitat fragmentation on New York's wildlife from multi-pad horizontal gas wells.

7.4.1.1 BMPs for Reducing Direct Impacts at Individual Well Sites

The Department proposes that the BMPs listed below be required mitigation measures to reduce impacts associated with development of individual wellpads and appurtenances located in natural habitats. During the permit review process, site-specific conditions would be considered to determine applicability of each BMP and permit conditions included as appropriate.

- Require multiple wells on single pads wherever possible;
- Design well pads to fit the available landscape and minimize tree removal;[469]
- Require "soft" edges around forest clearings by either maintaining existing shrub areas, planting shrubs, or allowing shrub areas to grow;
- Limit mowing to one cutting per year or less after the construction phase of well pads is completed. Mowing would not occur during the nesting season for grassland birds (April 23 – August 15);
- When well pads are placed in large patches of grassland habitat (greater than 30 acres) located within Grassland Focus Areas (as described in Section 7.4.1.2), construction and drilling activities are prohibited during grassland bird nesting season (April 23 – August 15);

[469] Environmental Law Clinic 2010.

- When well pads are placed in large patches of grassland habitat (greater than 30 acres) located within Grassland Focus Areas, minimize impacts from dust during the grassland bird nesting season (April 23 – August 15) by using dust palliatives and other appropriate measures to reduce dust;

- Require lighting used at wellpads to shine downward during bird migration periods (April 1 – June 1 and August 15 – October 15);

- Limit the total area of disturbed ground, number of well pads, and especially, the linear distance of roads, where practicable;[470]

- Design roads to lessen impacts (including two-track roads and oak mats in low-volume areas[471]) and limit canopy gaps;[472]

- Require roads, water lines, and well pads to follow existing road networks and be located as close as possible to existing road networks to minimize disturbance;

- Gate single-purpose roads to limit human disturbance; and[473]

- Require reclamation of non-productive, plugged, and abandoned wells, well pads, roads and other infrastructure areas. Reclamation would be conducted as soon as practicable and would include interim steps to establish appropriate vegetation during substantial periods of inactivity. Native tree, shrub, and grass species should be used in appropriate habitats.

7.4.1.2 Reducing Indirect and Cumulative Impacts of Habitat Fragmentation

The best opportunity for reducing indirect and cumulative impacts is to preserve existing blocks of the critically important grassland and interior forest habitats identified in Grassland and Forest Focus Areas (Figure 7.2) by avoiding site disturbance (wellpad construction) in those areas.

Grassland Focus Areas represent those areas within the State that are most important for grassland nesting birds. Forest Focus Areas represent those areas in the State that contain large blocks of forest interior habitats. Development in these areas would be conditioned as outlined below to mitigate impacts on wildlife from habitat fragmentation. The following measures are

[470] New Mexico Dept Game & Fish, 2007.

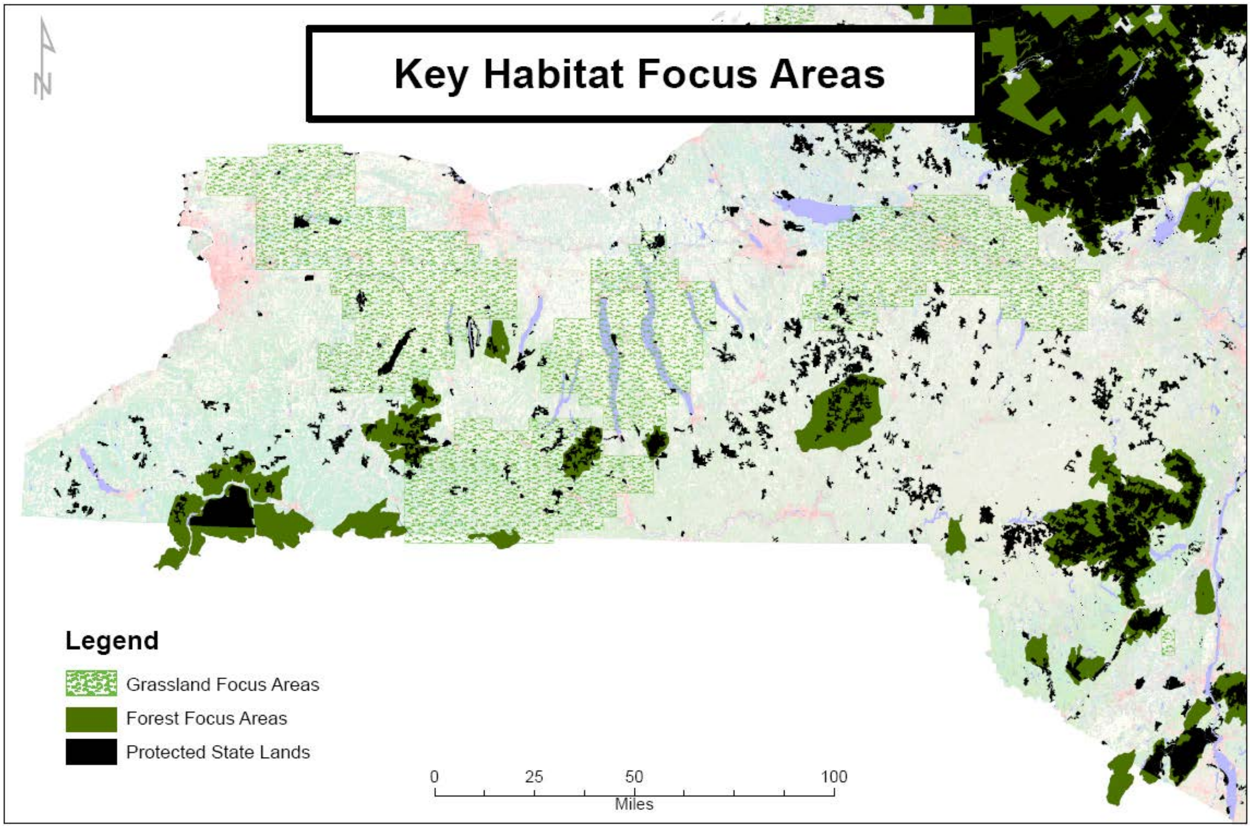
[471] Weller et al., 2002.

[472] NYSDEC, Strategic Plan for State Forest Management, 2010.

[473] New Mexico Dept Game & Fish, 2007.

considered necessary to mitigate the cumulative impacts of habitat fragmentation for these critically important habitat types while not strictly prohibiting development.

Figure 7.2 - Key Habitat Areas for Protecting Grassland and Interior Forest Habitats
(Updated August 2011)



Grassland Focus Areas

Grassland Focus Areas depicted in Figure 7.2 were determined by a group of grassland bird experts, including Department staff with input from outside experts representing federal agencies and academia.[474] The focus areas were derived from Breeding Bird Atlas (BBA) data from 2002-2004;[475] they were further modified by expert knowledge, and then followed up with a 2-year field verification study before being finalized. They represent areas of New York State that contain the most important grassland habitat mosaics.

474 See Morgan and Burger 2008.

475 McGowan and Corwin 2008 or visit DEC's website (http://www/dec/ny.gov/animals/7312.html).

The 2006 BBA provided the core dataset for delineating Grassland Focus Areas. All atlas blocks with a high richness of breeding grassland birds, as well as contiguous blocks also supporting grassland species, were included in the focus areas. The target for the focus areas was to "capture" or include at least 50% of the BBA blocks where each of the grassland species was found to be breeding across the state. The focus areas were able to reach that target for all but the most widespread species. Although the BBA does not provide estimates of abundance or densities, one of the criteria for inclusion in a focus area was contiguity with adjacent blocks containing grassland birds; analyses indicate that such blocks contain significantly higher abundances of the target species than isolated blocks.

Extensive field surveys were conducted in 2005 and 2006 throughout the focus areas. These surveys collected distribution and abundance data to confirm that the analysis of the breeding-bird data reflected actual conditions in the field (Table 7.4). A total of 487 different habitat patches were surveyed statewide. In some cases, focus area boundaries were adjusted based on field survey data. The overall process resulted in the identification of 8 focus areas that support New York's grassland breeding birds, 4 of which occur in the area underlain by the Marcellus Shale.

Table 7.4 - Principal Species Found in the Four Grassland Focus Areas within the area underlain by the Marcellus Shale in New York (New July 2011)

Grassland Focus Area	**Species**
Western Area	Upland sandpiper, vesper sparrow, horned leak, savannah sparrow, short-eared owl*
Southern Area	Northern Harrier, grasshopper sparrow, Eastern meadowlark, savannah sparrow
Middle Northern Area	Vesper sparrow, grasshopper sparrow, horned lark, savannah sparrow, short-eared owl*
Eastern Area	Northern harrier, short-eared owl*
*Wintering only	

Specific Mitigation Measures to Reduce Impacts to Grasslands

In order to mitigate impacts from fragmentation of grassland habitats, the Department proposes to require, through the permit process and/or by regulation, that surface disturbance associated with high-volume hydraulic fracturing activities in contiguous grassland habitat patches of 30 acres or more within Grassland Focus Areas would be based on the findings of a site-specific ecological assessment and implementation of mitigation measures identified as part of such ecological assessment, in addition to the BMPs required for all disturbances in grassland areas that are identified in Section 7.4.1.1. This ecological assessment would include pre-disturbance biological studies and an evaluation of potential impacts on grassland birds from the project. Pre-disturbance studies would be required to be conducted by qualified biologists and would be required to include a compilation of historical information on grassland bird use of the area and a minimum of one year of field surveys at the site to determine the current extent, if any, of grassland bird use of the site. Should the Department decide to issue a permit after reviewing the ecological assessment, the applicant would be required to implement supplemental mitigation measures by locating the site disturbance as close to the edge of the grassland patch as feasible and proposing additional mitigation measures (e.g., conservation easements, habitat enhancement). In addition, enhanced monitoring of grassland birds during the construction phase of the project and for a minimum period of two years following active high-volume hydraulic fracturing activities (i.e., following well completion) would be required.

Explanation for 30 Acre Threshold: Many of New York's rarest bird species that rely on grasslands are affected by the size of a grassland patch. Several species of conservation concern rely on larger-sized grassland patches and show strong correlation to a minimum patch size if they are to be present and to successfully breed. Minimum patch sizes will vary by species, and by surrounding land uses, but a minimum patch size of 30-100 acres is warranted to protect a wide assemblage of grassland-dependent species.[476] Although a larger patch size is necessary for raptor species, a minimum 30 acres of grassland is needed to provide enough suitable habitat for a diversity of grassland species. Grasslands less than 30 acres in size are of less importance since they do not provide habitat for many of the rarer grassland bird species.[477] The Grassland Focus Areas cover about 22% of the area underlain by the Marcellus Shale. However, the actual impacts on Marcellus development would affect less area for two reasons. First, only those portions of the Grassland Focus Areas meeting the minimum patch size requirement would be subject to the aforementioned additional restrictions on surface disturbance. Second, even in

[476] USFWS n.d., Sample and Mossman 1997, Mitchell et al. 2000.

[477] USFWS n.d., Sample and Mossman 1997, Mitchell et al. 2000.

areas where surface disturbance should be avoided, gas deposits could be accessed horizontally from adjacent areas where the restriction does not apply.

Forest Focus Areas

Forest Focus Areas depicted in Figure 7.2 were based on Forest Matrix Blocks developed by The Nature Conservancy (TNC).[478] TNC's goal in developing Forest Matrix Blocks was to estimate viability and resilience of forests and determine those areas where forest structure, biological processes, and biological composition are most intact. Resilient forest ecosystems can absorb, buffer, and recover from the full range of natural disturbances. TNC used three characteristics in developing their Forest Matrix Blocks: size, condition, and landscape context. Size was based on the key factors of the area necessary to absorb natural disturbance and species area requirements (see Figure 7.3).

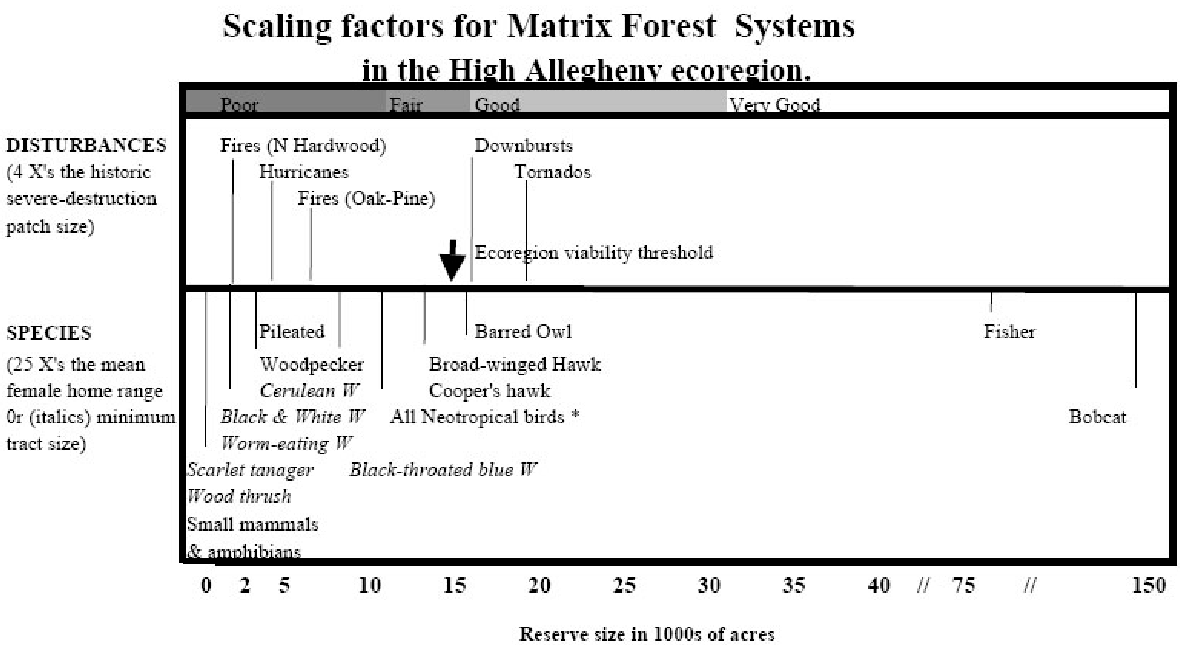
- **Natural disturbances and minimum dynamic area:** Eastern forests are subject to hurricanes, tornadoes, fires, ice storms, downbursts, and outbreaks of insects or disease. While most of these disturbances are small and recovery is fast, damage from larger catastrophic events may last for decades. Resilient forest ecosystems can absorb, buffer, and recover from the full range of natural disturbances. The effects of catastrophic events are typically spread across a landscape in an uneven way. Patches of severe damage are embedded in larger areas of moderate or light disturbance. Using historical records, vegetation studies, air photo analysis, and expert interviews, TNC scientists determined the size and extent of patches of severe damage for each disturbance type expected over one century. Historic patterns in the Northeast suggest that an area of approximately four times the size of the largest severe damage patch is necessary for a particular matrix block to remain adequately resilient.

    - **Breeding territories and area sensitive species:** Forest ecosystems must also be big enough to support characteristic interior species, including birds, mammals, herptiles, and insects. Many species establish and defend territories during breeding season, from which they obtain resources to raise their young. Twenty-five times the average size of a territory, together with information on other minimum area restrictions for that species, may be used as an estimate of the space needed for a small population. This reflects a rule of thumb developed for zoo populations on the number of breeding individuals required to conserve genetic diversity over generations (Figure 7.3);[479]

[478] TNC, 2003.

[479] TNC, 2003.

Figure 7.3 - Scaling Factors for Matrix Forest Systems in the High Allegheny Ecoregion[480] (New July 2011)



Factors to the left of the arrow should be encompassed by a 15,000 acre reserve
*Neotropical species richness point based on Robbins et al. 1989, and Askins, see text for full explanation]

- Condition was based on the key factors of structural legacies, fragmenting features, and biotic composition. TNC's criteria for viable forest condition were: low road density with few or no bisecting roads; large regions of core interior habitat with no obvious fragmenting feature; evidence of the presence of forest breeding species; regions of old growth forest; mixed age forests with large amounts of structure or forests with no agricultural history; no obvious loss of native dominants; mid-sized or wide-ranging carnivores; composition not dominated by weedy or exotic species; no disproportional amount of damage by pathogens; and minimal spraying or salvage cutting by current owners. Matrix blocks are bounded by fragmenting features such as roads, railroads, major utility lines, and major shorelines. The bounding block features were chosen due to their ecological impact on biodiversity in terms of fragmentation, dispersion, edge-effects, and invasive species; and

- Landscape context was based on the key factors of edge-effect buffers, wide-ranging species, gradients, and structural retention. In evaluating landscape context, TNC evaluated and recorded information on the surrounding landscape context for all matrix communities. TNC generally considered areas embedded in much larger areas of forest

480 From TNC, 2004.

> to be more viable than those embedded in a sea of residential development and agriculture. However, no area was rejected solely on the basis of its landscape context because the matrix forests in many of the poorer landscape contexts currently serve as critical habitat for forest interior species and may be the best example of the forest ecosystem type. Thus, this criterion was used to reject or accept some examples that were initially of questionable size and condition.

TNC applied the territory size and disturbance factors to all of the ecoregions in the Northeast, and tailored minimum size thresholds for matrix blocks to each ecoregion's forested extent, ecology, and natural disturbance history. The area underlain by the Marcellus Shale in New York is located in the High Allegheny Plateau (HAL) ecoregion (minimum block size of 15,000 acres), and contains 26 forest matrix blocks ranging in size from 17,000 acres to 176,000 acres, totaling 1.3 million acres. These matrix blocks are comprised of several dominant forest community types, including Northern hardwoods, maple-birch-beech forest, oak hickory forest and Allegheny oak forests.[481]

Specific Mitigation Measures to Reduce Impacts to Forests

In order to mitigate impacts from fragmentation of forest interior habitats, the Department proposes to require, through the permit process and/or by regulation, that surface disturbance associated with high-volume hydraulic fracturing activities in contiguous forest patches of 150 acres or more within Forest Focus Areas would be based on the findings of a site-specific ecological assessment and implementation of mitigation measures identified as part of such ecological assessment, in addition to the BMPs required for all disturbances in forested areas that are identified in Section 7.4.1.1. The ecological assessment would include pre-disturbance biological studies and an evaluation of potential impacts on forest interior birds from the project. Pre-disturbance studies would be required to be conducted by qualified biologists and would be required to include a compilation of historical information on forest interior bird use of the area and a minimum of one year of field surveys at the site to determine the current extent, if any, of forest interior bird use of the site. Should the Department decide to issue a permit after reviewing the ecological assessment, the applicant would be required to implement supplemental mitigation measures by locating the site disturbance as close to the edge of the forest patch as feasible and proposing additional mitigation measures (e.g., conservation easements, habitat

[481] TNC, 2002.

enhancement). In addition, enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required.

<u>Explanation for 150-Acre Threshold:</u> Fragmentation of large forest blocks can negatively affect breeding birds that require interior forest habitat for successful reproduction. Fragmentation due to human development of forest openings and structures that are relatively permanent will fragment habitats, create more edge, and reduce breeding success. Human-induced openings can influence breeding bird productivity several hundred feet from the edge of the forest through increased predation and increased nest parasitism. There is a wide diversity of bird species that rely on forest interior habitats to breed. As such, patch size requirements can vary widely by species, and can be influenced by surrounding land cover as well as the amount of forest cover on the landscape. Previous research on forest interior birds suggests that the minimum forest patch size needed to support forest breeding species ranges between 100 and 500 acres.[482] A 100-acre patch size is the minimum that would probably support a relatively diverse assemblage of forest breeding birds. Additional research indicates that the negative impacts along a forest edge extend between 200-500 feet into the forest.[483] If we assume a 100-acre forest patch with a 300-foot forested buffer, the minimum patch size for forest interior birds is approximately 150 acres of contiguous forest. Patches less than 150 acres are not of optimum value to forest interior birds. The Forest Focus Areas outside the Catskill Forest Preserve cover about 6% of the <u>area underlain by the</u> Marcellus Shale. However, the actual impacts on Marcellus development would affect less area for two reasons. First, only those portions of the Forest Focus Areas meeting the minimum patch size requirement would be subject to the aforementioned restrictions on surface disturbance. Second, even in areas where surface disturbance should be avoided, gas deposits could be accessed horizontally from adjacent areas. Given the horizontal reach of the wells, only about 2% of the subsurface areas would not be accessible.

[482] Roberts and Norment 1999, Hoover et al. 1995, Robbins 1979.

[483] Rosenburg et al. 1999, Robinson et al. 1995.

7.4.1.3 Monitoring Changes in Habitat

The following mitigation measures are necessary to better understand and evaluate the impacts of habitat fragmentation on New York's wildlife from multi-pad horizontal gas wells and would be required as permit conditions for any applications seeking site disturbance in 150-acre portions of Forest Focus Areas and 30-acre portions of Grassland Focus Areas:

- Conduct pre-development surveys of plants and animals to establish baseline reference data for future comparison;[484]
- Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion. Practice adaptive management as previously unknown effects are documented; and[485]
- Conduct test plot studies to develop more effective revegetation practices. Variables might include slope, aspect, soil preparation, soil amendments, irrigation, and seed mix composition.[486]

With the aforementioned measures in place, the significant adverse impacts on habitat from high-volume hydraulic fracturing would be partially addressed.

7.4.2 Invasive Species

Chapter 26 of the Laws of New York, 2008, amended the ECL to create the New York Invasive Species Council[487,488] and define the Department's authority regarding control of invasive species in New York. The Council, co-lead by the Department 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).

[484] New Mexico Dept Game & Fish, 2007.

[485] New Mexico Dept Game & Fish, 2007.

[486] New Mexico Dept Game & Fish, 2007.

[487] ECL § 9-1707.

[488] 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.

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.[489]

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 also prepared a report that described a regulatory system for non-native species[490] and included a four-tier system for preventing the importation and/or release of non-native animal and plant species. The system contains 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.

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.

7.4.2.1 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, the Department proposes that well operators be required to conduct all activities in accordance with the best management practices below. This would be reflected by a permit condition (see Appendix 10) requiring the preparation and

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489 ECL §9-1705(5)(b).

490 Final report – A regulatory system for non-native species. New York Invasive Species Council. 10 June 2010. http://www.dec.ny.gov/docs/lands_forests_pdf/invasive062910.pdf.

implementation of an invasive species mitigation plan that would 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 proposes to require that well operators submit, with the EAF Addendum for a single well or the first well proposed on a multi-well pad, a comprehensive survey of the entire project site, documenting the presence and identity of any invasive plant species. The survey should be conducted by an environmental consultant familiar with the invasive species in New York. This survey would establish a baseline measure of percent aerial coverage and, at a minimum, would be required to include the plant species identified on the Interim List of Invasive Plant Species in New York State.[491] A map (1:24,000) showing all occurrences of invasive species within the project site would also be required to be 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 would be required to be clearly identified in the field with signs, flagging, and/or stakes prior to any ground disturbance. If the invasive species survey submitted with the EAF Addendum shows the presence of specific invasive species, consultation with the Department may be 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, including roots and rhizomes, 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

[491] This list appears in Tables 6.3 and 6.4.

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 would be required to 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 should not be washed in any waterbody or wetland, and run-off resulting from washing operations should not be allowed to directly enter any water bodies or wetlands. Appropriate erosion control measures would be required be employed;

- Loose plant and soil material that has been removed from clothing, boots and equipment, or generated from cleaning operations would 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 would be required to 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 location, including but not limited to trucks, tractors, excavators, and any hand tools, would be required to 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; and

- 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 should be obtained from a source known to be free of invasive species; and

- 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 would be required to 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 would be required to 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; and

- Any new invasive species occurrences found at the project location should be removed and disposed of appropriately.

7.4.2.2 Aquatic[492]

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

[492] Alpha, 2009, p. 3-6 *et seq.*, and supplemented by DEC.

approval. Either of these options avoids the transfer of invasive species into a new habitat or watershed. Precautions would be required to 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 water body to another.

Regulatory protections exist to reduce the potential for the transfer of aquatic invasive species. Regulations and policies of SRBC and DRBC both address the transfer, reuse and discharge of water and SRBC requires appropriate treatment to prevent the spread of aquatic invasive species. Table 7.5 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 7.5 do not specifically relate to invasive species, but the required actions and policies nonetheless may have the effect of reducing or eliminating their transport.

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."

TABLE 7.5
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 resul 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 ar
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.

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 help to address the potential for transfer of invasive species associated with water use for high-volume hydraulic fracturing. These protocols, however, are not explicit nor do they apply to the entire area subject to natural gas activities covered by this SGEIS. Thus, in addition to the requirements of SRBC and DRBC, the Department recommends that the following best management practices be instituted and incorporated into the required invasive species mitigation plan to reduce the risk of transferring invasive species from both the exportation and importation of fresh water. These best management practices target two specific pathways for the transfer of invasive species, namely the vehicles and equipment used to transfer the fresh water and the fresh water being moved between sites and/or discharged.

Best Management Practices for vehicles and equipment:

1. Inspect all vehicles and equipment including trucks, trailers, pumps, hoses, screens, gates, etc. prior to deployment to new site;

2. Drain all hoses and equipment at collection site after use;

3. Clean all mud, vegetation, organisms and debris and dispose on site if the contaminants originated at site; dispose in 3 mil trash bags and dispose in trash if contaminants were transported from another site;

4. When withdrawing water from waters at multiple surface water locations on a single water body, begin at furthest upstream collection point;

5. Before moving to another water body, decontaminate equipment that has come in contact with surface water using appropriate protocols outlined below:

    - Pressure wash with 140º F water at contact point for 3 minutes or disinfect with 200 ppm (0.5 oz/gallon) chlorine for 10 minute contact time; keep disinfection solution from entering surface waters; and

    - Dry (regardless of treatment);

6. Well operators should provide truck and equipment drivers and operators with clear instructions, inspection checklists identifying areas on the vehicles or equipment most likely to harbor invasive species, and specifications and protocols for cleaning and disinfection; and

7. Document all inspections, cleaning and disinfection activities in a log that would be required to be maintained by the well operator and made available to the Department upon request. At a minimum this log would be required to include:

    - Dates and times of all inspection and cleaning/disinfection activities;

    - Identification of the vehicles and equipment inspected and cleaned/disinfected; and

    - Information regarding the method of cleaning/disinfection.

Best Management Practices for fresh water:

1. Transport unused fresh water via truck or pipeline to other drilling locations where it can be discharged into tanks or for subsequent use; and

2. If fresh water cannot be used at another drilling location, dispose of unused fresh water over land (not in surface water or in manner that drains directly to surface water), preferably in same drainage area as collected, and using appropriate erosion control measures.

7.4.3 Protecting Endangered and Threatened Species

Prospective project sites should be screened against the Department's Natural Heritage Database to determine if endangered or threatened species are known to occur within the vicinity. The best method for reducing impacts to these species is to avoid siting projects in locations and habitats known to be utilized by endangered and threatened wildlife.

Whenever possible, impacts to endangered and threatened animal species should be avoided. The process for accomplishing this is laid out below:

- As part of the EAF, the project proponent should do at least one of the following to screen the project site for potential endangered and threatened animal species:
- Request a screening from the New York Natural Heritage Program;
- Self-screen utilizing the Nature Explorer and Environmental Resource Mapper web tools on the Department's website; or
- Conduct site-specific surveys to determine if endangered and threatened animal species are present at the project site;
- If any endangered and threatened animal species are found to occur in the vicinity of the project site, the project proponent should consult with the Regional Department Natural Resources Office;
- Regional Department staff can work with project proponent to identify how species may be affected;
- Project proponent changes the location of the proposed project or otherwise modifies the project to avoid any potential "take" of a protected species identified by Department staff; and
- If the "take" of an endangered and threatened species is deemed to be unavoidable, the project proponent would be required to apply for an Incidental Take Permit.

The specific procedure for applying for the Incidental Take Permit is set forth in the Department's regulations at 6 NYCRR Part 182 and is summarized below:

- The applicant develops an endangered or threatened species mitigation plan;
- The applicant develops an implementation agreement that affirms how the mitigation plan will be accomplished;
- The Department reviews the mitigation plan and implementation agreement to determine if it meets applicable regulatory criteria; and
- If the Department approves the mitigation plan and implementation agreement and all other regulatory criteria are met, then an Incidental Take Permit can be issued, subject to the requisite SEQRA review.

The Department finds that with the implementation of the above measures, impacts on protected endangered and threatened species would be reduced.

7.4.4 Protecting State-Owned Land

As discussed in Section 6.4.4, the following issues are of significant concern as they relate to State-owned forests, wildlife management areas and parklands, and the potential impacts upon them (See also Sections 6.4.1 and 7.4.1):

- Forest fragmentation: Because of their size and long-term ownership, the specified state-owned public lands are integral to providing continuous interior forest habitat conditions and are protected from industrial development. The road systems needed to conduct drilling and fracturing operations represent significant potential impacts to this important habitat type;

- Grassland fragmentation: Because of their size and long-term ownership, the specified state-owned lands are integral to providing grassland habitat conditions and are protected from industrial development. The road systems needed to conduct drilling and fracturing operations represent significant potential impacts to this important habitat type;

- Public recreation: The level of truck traffic associated with horizontal drilling and high volume hydraulic fracturing, the presence of drilling rigs and compressor complexes, and the need to light well pads during drilling and fracturing operations would be likely to create significant impacts on public recreation opportunities during the construction, drilling and fracturing phases of development; and

- Wildlife impacts: Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration. The activities creating these impacts could take place for up to three years at any one site, depending on how many wells are drilled from a particular well pad. The local wildlife populations could take years or even decades to recover.

As an example for one natural gas reservoir that could be developed by high-volume hydraulic fracturing, State Forests, Wildlife Management Areas and State Parks comprise less than 6% of the area underlain by the Marcellus Shale in New York State. (As stated in Chapter2, drilling will not occur on Forest Preserve lands because the State Constitution prevents their being leased or sold.) Acknowledging that there will likely be physical, technological, ownership and leasing impediments to reaching all areas under State-owned forests, wildlife management areas and parklands, it is still likely that less than 3% of the Marcellus Shale formation would be rendered unavailable by prohibiting horizontal drilling and high-volume hydraulic fracturing surface disturbance on these lands.

In order to ensure that the State fulfills the purposes for which State Forests and State Wildlife Management Areas were created, no surface disturbance associated with horizontal drilling and high-volume hydraulic fracturing would be permitted on State Forests or Wildlife Management Areas. This prohibition does not include accessing subsurface resources located within these areas from adjacent private lands. With the surface disturbance restriction in place, the Department concludes that impacts to the specified state-owned lands from high-volume hydraulic fracturing would be reduced. Current OPRHP policy would impose a similar restriction on State Parks.

7.5 Mitigating Air Quality Impacts

This section identifies mitigation measures which are necessary, or may be necessary, to achieve compliance with Federal and State air quality standards, State air quality guidelines and State and Federal regulations. A detailed discussion of the Department's air quality impact assessment and analysis of applicable State and Federal regulatory requirements and regional air quality considerations which give rise to these mitigation measures is presented in Section 6.5. This section focuses on the following four points. First, the section identifies pollution control measures required to ensure compliance with ambient air quality standards for criteria air pollutants and State ambient air thresholds for toxic pollutants. This information is discussed in detail in Section 6.5.2 and, therefore, is included here in summary form. Second, this section includes a more detailed discussion of pollution control techniques required pursuant to State and Federal regulations for specific pollutants, such as NO_x, where emissions would be affected by the type of equipment and fuel to be used. The Department will address the different approaches, including various operational scenarios and equipment which can be used to achieve compliance. Third, this section summarizes the total suite of mitigation measures for well pad operations. Fourth, this section outlines an approach to mitigate formaldehyde emissions from the compressor station.

7.5.1 Mitigation Measures Resulting from Regulatory Analysis (Internal Combustion Engines and Glycol Dehydrators)

This section outlines the potential mitigation measures which would be best suited for given types of engine and fuel combinations to control NO_x; the use of ULSF fuel in diesel engines to control sulfur oxide emissions; and mitigation measures for glycol dehydrators. Section 7.5.2 identifies SCR as the NO_x control measure recommended for diesel engines as a result of the review of manufacturer's information and current use based on the detailed dispersion modeling assessment in Section 6.5.2. In addition, based on the modeling analysis, particulate traps are deemed the control technology of choice for certain tier diesel engines. Section 7.5.3 outlines all mitigation measures deemed necessary to assure compliance with Federal and State air quality standards. State air quality guidelines and Federal and State regulations are detailed in Section 6.5.

7.5.1.1 Control Measures for Nitrogen Oxides - NO_x

Control Techniques for Natural Gas Engines

Three generic control techniques have been developed for reciprocating engines: 1) parametric controls (timing and operating at a leaner air-to-fuel ratio); 2) 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 3) post-combustion catalytic controls installed on the engine exhaust system. Post-combustion catalytic technologies include SCR for lean-burn engines, NSCR for rich-burn engines, and CO oxidation catalysts for lean-burn engines. For example, the off-site compressors will be required to use an oxidation catalyst.

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 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 %, while CO reduction efficiencies are approximately 90 %.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 % 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 %. 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 (SCR) - SCR is a post-combustion technology that has been shown to effectively reduce 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. SCR 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. NO_x, 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 would be within a particular temperature range (typically between 450° F and 850° F). 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 (850º F) 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 %. 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 effectively reduce 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 % for two-stroke lean-burn engines and 90 % for 4-stroke lean-burn engines.

Control Techniques 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, post-combustion techniques, such as SCR and NSCR, are currently also 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. Increasing the volume lowers the combustion temperature and pressure, 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 pre-combustion 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 the system 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.

7.5.1.2 Control Measures for Sulfur Oxides - SO_x

Sulfur oxide emissions are a function of only the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 creates sulfur trioxide (SO_3), which reacts with water to create sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to create sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.

Past communications with representatives of natural gas producer Chesapeake Energy indicated contractors that provide approximately 80% of the diesel rigs to the industry are using ultra low sulfur fuel (ULSF, 15ppm) because of the reduced availability of the alternative low sulfur fuel. Industry has identified the use of ULSF for all engines as a mitigation measure in their Information Report in response to Department requests.

The final EPA regulation at 40 CFR Part 63 Subpart ZZZZ (Engine MACT rule) described in Appendix 17 will mandate the use of ultra low sulfur fuel (ULSF). Accordingly, ULSF is being required for all engines to be used in New York Marcellus Shale activities.

7.5.1.3 Natural Gas Production Facilities Subject to NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators)

40 CFR Part 63, Subpart HH imposes specific control requirements on TEG dehydrator units. Area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described in Section 6.5.1.2, 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 % or more (generally by a condenser with a flash tank); or 2) reduce HAP emissions to an outlet concentration of 20 ppm by volume (ppmv) or less (for combustion devices); or 3) reduce benzene emissions to a level less than 1.0 Tpy. 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.

Area source TEG dehydration units with natural gas throughput and benzene emission rates above the cutoff levels described in Section 6.5.1.2, must reduce emissions by lowering the glycol circulation rate to less than or equal to an optimum rate. The optimum rate is determined by the following equation:

$$LOPT = 1.15*3.0 \frac{\text{gal TEG}}{\text{lb } H_2O} * \frac{\{F*(I - O)\}}{\{24\text{hr/day}\}}$$

Where:
LOPT = Optimal circulation rate, gal/hr.
F = Gas flowrate (MMSCF/D).
I = Inlet water content (lb/MMscf).
O = Outlet water content (lb/MMscf).

The constant 3.0 gal TEG/lb H_2O 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.

All glycol dehydrator units used at the well pad will be required to assure compliance with the 1 Tpy benzene emission limit using the above equation and necessary data and, in the event of wet gas, apply a condenser to assure such compliance.

7.5.2 Mitigation Measures Resulting from Air Quality Impact Assessment and Regional Ozone Precursor Emissions

The modeling analysis conducted and described in Section 6.5.2 concluded that most of the air quality standards and ambient thresholds will be met under the operations scenarios described by industry, including certain self-imposed restrictions on these operations. For example, industry has committed to: 1) limiting the number of wells to be drilled and completed per pad and per year to a maximum of four; 2) not operate drilling and hydraulic fracturing engines simultaneously at a single well pad; and 3) limit the amount of gas to be vented and flared per well. Even with these restrictions, however, certain air quality standards and ambient thresholds are projected to be exceeded for certain pollutants and, therefore, further mitigation measures are necessary. Section 6.5.2 details the specific pollutants of concern and the associated additional mitigation measures necessary to achieve standards compliance. For the mitigation measures necessary for the drilling and hydraulic fracturing engines, the review process and analysis conducted to support the specific control techniques recommended by the Department is also detailed.

In summary, the Department has determined that the modeling results support the following conclusions for the necessary mitigations which would be necessary for ambient standards compliance:

1) In order to meet the annual benzene ambient guideline concentration (AGC) due to the glycol dehydrator emission, the stack height needs to be a minimum of 30 feet even with the benzene emission limit of 1 Tpy;

2) The gas venting has to use a minimum stack height of 30 feet if "sour" gas is encountered in order to meet the 1-hour standard for H_2S;

3) The off-site compressor must have a minimum stack height of 25 feet, in addition to the oxidation catalyst required by regulation, in order to meet the formaldehyde annual threshold; and

4) Certain EPA "Tier" drilling and hydraulic fracturing engines will not be allowed for use in New York Marcellus activities, while others must be equipped with particulate traps and SCR controls.

Section 6.5.2.6 details measures required for specific tiers of engines. With respect to these specific measures for engines, industry is allowed to provide alternative measures which can demonstrate the equivalent emission reductions and standards compliance. In addition to these measures, based on the modeling results, additional controls to reduce NO_x emissions might be necessary in the future to address the Ozone NAAQS SIP requirements. The full set of control measures resulting from the regulatory and modeling assessments are provided in Section 6.5.5 and are repeated in the next section for convenience.

7.5.3 Summary of Mitigation Measures to Protect Air Quality

7.5.3.1 Well Pad Activity Mitigation Measures

The necessary control measures resulting from the air quality assessments will be imposed on the well pad activities through the well permitting process, as described in Section 6.5.5. Based on industry's self-imposed limitations on operations and Department's determination of conditions necessary to reduce or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions must be imposed in the well permitting process:

- The diesel fuel used in drilling and hydraulic fracturing engines will be limited to ULSF with a maximum sulfur content of 15 ppm;

- Drilling and fracturing engines will not be operated simultaneously at the single well pad;

- The maximum number of wells to be drilled and completed annually or during any consecutive 12-month period at a single pad will be limited to four;

- The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to one ton/year;

- Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions;

- During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);

- During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12-month period;

- Wellhead compressors will be equipped with NSCR controls;

- No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines will be used for any activity at the well sites;

- The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and

- The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

The EAF Addendum will require information regarding stack heights. If stack heights shorter than those specified in Table 7.6 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.

Table 7.6 - Required Well Pad Stack Heights to Prevent Exceedances

Equipment	Pollutant	Stack Height
Flowback vent	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 7.5.1.3 is also required.

7.5.3.2 Mitigation Measures for Off-Site Gas Compressors

As concluded in Sections 6.5.1.8 and 6.5.5, any off-site compressor “stations” will require a case by case air permit review pursuant to the Department’s air permitting regulations. Thus, all necessary control measures, such as the stack height necessary to avoid exceedances of the annual formaldehyde, will be determined for each compressor during the application review process. From the regulatory requirements described in Section 6.5.1, an oxidation catalyst will be required to reduce the emissions of CO, VOCs and formaldehyde in all instances.

7.6 Mitigating GHG Emissions

Potential GHG emissions are discussed in Section 6.6 for the siting, drilling and completion of 1) single vertical well, 2) single horizontal well, 3) four-well pad (i.e., four horizontal wells at the same site), and respective first-year and post first-year 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. 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

EPA's 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.[493] Natural Gas STAR partners can implement a number of voluntary activities to reduce GHG emissions from both exploration and production activities. The Department strongly encourages active participation in the program. Therefore, an example of a measure that could be included in a greenhouse gas emissions impacts mitigation plan includes:

- Proof of participation in the EPA's Natural Gas STAR Program to reduce methane emissions (see Appendices 24 and 25).[494]

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493 http://www.epa.gov/gasstar/.

494 http://www.epa.gov/gasstar/join/index.html.

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:

- 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 to minimize the travel distance;
- Using materials that are extracted and/or manufactured within the State or region to minimize the shipping distance;
- 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;
- 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., hydraulic fracturing fluids);
- Using efficient hydraulic fracturing pump engines;
- Using efficient exterior lighting;
- Limiting flaring during the flowback phase by using REC equipment (see Appendix 25);
- If allowed by the 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;
- Flaring methane instead of venting; and

- Performing leak detection surveys and taking corrective actions.

Two years after the completion date of the first well drilled and completed under the SGEIS, the Department would analyze the actual usage of RECs in New York, and examine existing conditions relative to industry's development of the Marcellus Shale and other low-permeability gas reservoirs, and PSC's position on the timing of pipeline installation as discussed in Chapter 8. At the same time, the Department would evaluate a possible additional REC requirement under certain circumstances through a new supplementary permit condition for high-volume hydraulic fracturing.

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 CH_4. 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 EPA's Natural Gas STAR BMPs including below;[495]
- Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry;[496]
- Reducing Methane Emissions from compressor rod packing systems;[497]
- Reducing emissions when taking compressors off-line;[498]
- Replacing Glycol Dehydrators with Desiccant Dehydrators;[499]

[495] http://www.epa.gov/gasstar/tools/recommended.html.

[496] http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.

[497] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

[498] http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf.

[499] http://www.epa.gov/gasstar/documents/ll_desde.pdf.

- Replacing gas-assisted glycol pumps with electric pumps;[500]
- Optimizing glycol circulation and installing flash tank separators in glycol dehydrators;[501]
- Using efficient compressor engines;
- Using efficient line heaters;
- Using efficient glycol dehydrators;
- Re-using production brines;
- Ensuring all flow connections are tight and sealed;
- Performing leak detection surveys and taking corrective actions;
- Using efficient exterior lighting; and
- Using solar-powered telemetry devices.

7.6.7 Leak and Detection Repair Program

Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would include as part of the operator's greenhouse gas emissions impacts mitigation plan which is required for any well subject to permit issuance under the SGEIS. In accordance with the corresponding plan developed by the operator to meet the Leak Detection and Repair Program's below minimum requirements, an annual report for the calendar year would be completed by March 31 of each following year. Each annual report would be retained by the site owner for a minimum period of 5 years and would be made available to the Department upon request. The report would include the inspection results of the inspections and repairs completed and an explanation for any repairs that were not completed. The report would be accompanied by the certification of a company official that all repairs completed were in accordance with company policies and the requisite plan, and include a schedule for completion of repairs for any remaining leaks identified in the

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500 http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf.

501 http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf.

report. In addition, based on the leak history of a site, the report would include an evaluation and determination of the adequacy of the existing inspection procedures and schedule or a plan to modify existing procedures and/or increase the number of inspections in the current and future years. The Leak Detection and Repair Program may be modified at the operator's discretion provided it continues to meet the minimum requirements of the SGEIS.

The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements.

- There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;

- Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;

- All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves, vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and

- Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt.

7.6.8 Mitigating GHG Emissions Impacts - Conclusion

Well operators can reduce their GHG emissions through active participation in the EPA's Natural Gas STAR Program, leak detection and repair, and through effective planning and implementation of necessary activities. The Department proposes to require, as a permit condition for high-volume hydraulic fracturing 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 applicable Department policy documents. However, the impacts mitigation plan would, at a minimum, include:

- A list of GHG-related BMPs planned for implementation at the permitted well site;
- A Leak Detection and Repair Program consistent with the SGEIS;
- Required use and a description of EPA's Natural Gas STAR Best Management Practices for any equipment (e.g., low bleed gas-driven pneumatic valves and pumps) located from the wellhead to the onsite separator's outlet (Department's regulatory authority cutoff as described in Chapter 8);
- A description of planned use of reduced emissions completions, if any, including an estimate of the amount of methane that would be recovered instead of flared by the use of such; and
- A statement that upon request the operator would provide the Department with a copy of its report(s) for New York State as required under the EPA's GHG reporting rule discussed in Chapter 8. The operator would provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, records would be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.

Further, partners in EPA's Natural Gas STAR Program should include proof of their participation and starting date. The operator's greenhouse gas emissions impacts mitigation plan would be available to the Department upon request.

The Department proposes to require, via permit condition, the following additional requirements:

- Gas vented through the flare stack would be ignited whenever possible. The stack would be equipped with a self-ignition device; and
- A reduced emissions completion, with minimal flaring (if any), would be performed whenever a sales line is available during completion at any individual well or the multi-well pad.

7.7 Mitigating NORM Impacts

7.7.1 State and Federal Responses to Oil and Gas NORM[502]

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. 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).

7.7.2 Regulation of NORM in New York State

In New York State, the handling of radioactive material and waste 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 NYSDOH 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 Department under its 6 NYCRR Part 380 series of regulations. Additionally, the Department's solid waste disposal regulations, Part 360, precludes disposal of wastes regulated under Part 380 in a Part 360 solid waste landfill.

[502] Alpha, 2009, p. 2-44 et seq.

Disposal of flowback waster or brine through a POTW is addressed in section 7.1.8.1.

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 licensed radioactive material and processed and concentrated NORM (such as waste filters, sludges, or backwash from the treatment of flowback water or production brine) into the environment is regulated by the Department. NORM contained in flowback water or production brine may be subject to applicable SPDES permit conditions.

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 in pipes and equipment may require licensing of a facility. The results also indicate that production brine may be subject to discharge limitations to ensure compliance with Part 380.

Existing data from drilling in the Marcellus Formation in other States, and from within New York for wells that were not hydraulically fractured, shows significant variability in NORM content. This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability. During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York.

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 pipe 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 would need to be tested for NORM concentrations in order to ensure compliance with regulatory requirements.

The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup. The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27.

The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would reduce any potential significant impacts from NORM.

7.8 Socioeconomic Mitigation Measures[503]

High-volume hydraulic fracturing operations would have many positive socioeconomic results in the local areas where development is expected to occur. These operations would likely result in a substantial increase in economic activity in the affected areas, as well as a substantial increase in tax revenues to the state and localities. However, as described in previous sections, this increased economic activity would also have the potential to result in adverse impacts in regions with high drilling activity, particularly acute in the short term, including localized impacts on the housing market caused by the in-migration of construction and production workforces and an

[503] Section 7.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

increase in demand for certain state and local government services, resulting in increased government expenditures.

As discussed in Section 6.8, potentially significant adverse impacts on local communities associated with an increase in population and increased demand for housing and community services are tied to the rate of development. Impacts that were potentially significant under the average development scenario were not as significant under the low development scenario. Similarly, impacts on population, housing, and community services are more significant when concentrated in smaller geographic areas than when incurred across broader geographic areas or statewide. The rate and concentration of development also affects the significance of impacts on visual resources, the ambient noise environment, and transportation networks.

The rate and concentration of development is related to many factors that cannot necessarily be controlled, such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of state and nation, which will all affect the overall rate of development, as well as the uncertainty in the development potential of the Marcellus and Utica Shales.

Through its permitting process, the Department will monitor the pace and concentration of development throughout the state to mitigate adverse impacts at the local and regional levels. The Department will consult with local jurisdictions, as well as applicants, to reconcile the timing of development with the needs of the communities. Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area.

Another way to mitigate the potential adverse impacts associated with in-migration to the region would be to actively encourage the hiring of local labor. Because natural gas exploration, drilling, and production activities typically require specialized skills, a jobs training program or apprentice program should be developed through the SUNY system (e.g., community colleges and agricultural and technical colleges) to increase the number of local residents with the requisite job skills for the natural gas industry, thereby reducing the number of workers that would need to be hired from outside the region. Such a program would also have the benefit of reducing unemployment in these regions. A jobs training program would not eliminate the need for in-migration of skilled labor, but the program could partially offset the in-migration of workers and thus partially offset the potential housing impact from such in-migration.

7.9 Visual Mitigation Measures[504]

As noted, in most cases high-volume hydraulic fracturing operations would not result in significant adverse impacts on visual resources as set forth in NYSDEC DEP-00-2, "Assessing and Mitigating Visual Impacts" (NYSDEC 2000). The most significant visual impacts would result from construction of the well pad and well, and those impacts would be of short duration. Nevertheless, this section describes generic measures to address temporary adverse impacts of well site construction, development, production, and reclamation on visual resources. These measures could be undertaken in cases where well construction takes place near visually sensitive areas identified within the area underlain by the Marcellus and Utica Shales in New York State. Measures to mitigate impacts on visual resources would be generally similar, regardless of the type of visual resource or its location, and despite the need for compliance with rules, regulations, and permits promulgated by other federal, state, and/or local (town, county or regional) agencies.

The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, "Assessing and Mitigating Visual Impacts" (NYSDEC 2000). These measures can generally be divided into: design and siting measures that could be incorporated during the construction, development, and production phases; maintenance measures that could be incorporated into the development and production phases; and decommissioning measures that could be incorporated into the reclamation phase. Offsetting mitigation, as opposed to avoidance and direct mitigation measures, would typically be used only as a last resort for the resolution of significant impacts on visual resources or visually sensitive areas, as determined by Department staff. These measures are discussed in greater detail in the following subsections.

504 Section 7.9, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

Generally, mitigation measures would be developed in consultation between Department staff and well operators and would be site-specific, or project-specific where multiple sites are a part of the project design. Depending on the location of the well pad and the resource potentially impacted, it may also be necessary to consult with additional state and federal regulatory agencies to develop measures to mitigate visual impacts on specific types of visual resources or visually sensitive areas, including but not limited to the New York State Historic Preservation Officer for NRHP-listed or -eligible historic properties; consultation with the National Park Service for National Historic Landmarks (NHLs) and National Natural Landmarks (NNLs); consultation with the U.S. Fish and Wildlife Service for National Wildlife Management Areas; consultation with the NYSDOT for state-designated Scenic Byways, etc.; and consultation with local (town, county, or regional) agencies for locally designated visual resources or visually sensitive areas that were identified on the EAF.

7.9.1 Design and Siting Measures

Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). These various design and siting techniques are summarized below.

- **Screening**. Screening uses natural or man-made objects to conceal other objects from view; these objects may be constructed of any material that is opaque.

- **Relocation**. Relocation consists of moving facilities or equipment within a site to take advantage of the mitigating effects of topography and/or vegetation.

- **Camouflage or disguise**. Camouflage or disguise consists of using forms, colors, materials, and patterns to minimize or mitigate visual impacts.

- **Low profiles**. The use of low profiles consists of reducing the height of on-site objects to minimize their visibility from surrounding viewsheds.

- **Downsizing**. Downsizing consists of reducing the number, areas, or density of objects on a site to minimize their visibility from surrounding viewsheds.

- **Alternative technologies**. The use of alternative technologies consists of substituting one technology for another to reduce impacts.

- **Non-reflective materials**. The use of non-reflective, materials consists of using materials that do not shine or reflect light into surrounding viewsheds.

- **Lighting**. Lighting should be the minimum necessary for safe working conditions and for public safety, and should be sited to minimize off-site light migration, glare, and 'sky glow' light pollution.

Design and siting measures are the simplest and most effective methods for avoiding, minimizing, or mitigating direct and indirect impacts on visual resources or visually sensitive areas. For example, the state has determined that surface drilling would be prohibited on state-owned land, including reforestation areas and wildlife management areas, which would include many of the types of visual resources or visually sensitive areas discussed in Section 2.3. Implementing this siting measure would result in the exclusion from surface drilling of many resources and areas that may be designated or used, in part or in whole, for their scenic qualities, thereby decreasing the potential for direct visual impacts of surface drilling on such resources or areas. The implementation of design and siting measures would also minimize indirect impacts on visual resources or visually-sensitive areas that are outside of, but in close proximity to, areas where drilling is proposed.

Additional use of design and siting measures to avoid, reduce, or mitigate visual impacts would typically be implemented during the construction, development, and production phases of a well site. These measures could be used individually or in combination as determined appropriate and feasible by Department staff and well operators.

For example, the use of multi-well pads for horizontal drilling and hydraulic fracturing is a design and siting measure that incorporates both relocation and downsizing techniques by installing more than one well in one location. The benefit of the multi-well pad is that it decreases the overall number of pads in the surrounding landscapes, which would result in the decreased potential for impacts on visual resources or visually sensitive areas during the construction, development, production, and reclamation phases.

The use of horizontal drilling and high-volume hydraulic fracturing is a design and siting measure that incorporates the use of alternative technology to extract natural gas from the prospective Marcellus and Utica Shale region. The benefit of horizontal drilling and high-volume hydraulic fracturing is that it provides flexibility in pad location, such that well pads can be sited to avoid or minimize the potential for temporary, short-term, and long-term impacts on visual resources or visually sensitive areas during the construction, development, production, and reclamation phases (NTC 2011). Such considerations should be reflected in Department consideration of well pad applications.

The potential benefit of using camouflage or disguise as a design measure to minimize impacts on visual resources or visually sensitive areas is shown in Photo 7.1 below. This photo shows fracturing activities on a well site, a phase when well sites are almost entirely filled with on-site equipment, which represents new landscape features and results in an area that appears visually prominent in views from nearby vantage points. Although the fracturing phase of development is considered temporary and periodic (as described in Table 6.53), it would be possible to minimize visual impacts during fracturing activities that might occur in the spring, summer, or fall by requiring on-site water storage tanks (the red tanks in Photo 7.1) to be a green color to mimic surrounding conditions. This would reduce the prominence of the tanks in the surrounding landscape during seasons when visual resources or visually sensitive areas are typically visible to the greatest numbers of the viewing public.

The 2010 visual impact assessment (Upadhyay and Bu 2010) evaluated the effectiveness of implementing certain design and siting techniques as measures to mitigate visual impacts. Using aerial photograph interpretation, the authors suggested that reducing the size of the well pad (downsizing) after drilling (the development phase) was complete could result in reduced site-specific visual impacts from surrounding vantage points and that reducing the density of multiple well pads in an area could result in reduced visual impacts within a larger area or region (e.g., within a county). Their study further suggested that the following design and siting measures would avoid or minimize visual impacts from surrounding vantage points: relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow) (Upadhyay and Bu 2010).

Photo 7.1 - View of a well site during the fracturing phase of development,
with maximum presence of on-site equipment. (New August 2011)

A tourism study (Rumbach 2011) prepared for the Southern Tier Central (STC) Regional Planning and Development Board suggests that visual impacts from horizontal drilling and hydraulic fracturing could be most effectively addressed during the siting and design phases by ensuring that well pads are designed and located in ways that minimize potential impacts on visual resources or visually sensitive areas to the extent practicable. The study also encourages the inclusion of visual impact mitigation conditions, developed in accordance with NYSDEC DEP-00-2, in permits when visual resources may be impacted. The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. Additional recommendations included encouraging local agencies (towns, counties, and regions) to identify areas of high visual sensitivity, which may require additional visual mitigation, and to develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects (Rumbach 2011).

7.9.2 Maintenance Activities

The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming "eyesores." Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project (NYSDEC 2000).

Maintenance activities to avoid, reduce, or mitigate visual impacts would typically be implemented during the development and production phases for well sites. Facilities should be maintained in good repair and as organized and clean as possible.

Upadhyay and Bu's visual impact assessment evaluated the effectiveness of site restoration to minimize visual impacts on surrounding landscapes. Their definition of site restoration as a mitigation measure, defined as restoring drilling pads to their original condition after drilling and hydraulic fracturing activities (i.e., the development phase) are completed, is similar in concept to the NYSDEC DEP-00-2 definition of maintenance activities as a mitigation measure. Their conclusion was that site restoration following drilling and hydraulic fracturing activities was an effective way to reduce adverse visual impacts of producing well sites within the existing landscape. With appropriate site restoration, well sites in the production phase, when activity is minimal and there are only a few relatively unobtrusive aboveground structures on site, are not prominent features within the surrounding landscape (Upadhyay and Bu 2010).

7.9.3 Decommissioning

The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites.[505] Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration (NYSDEC 2000).

The tourism study prepared for the STC (Rumbach 2011) discusses additional measures that could be implemented during the reclamation phase to mitigate visual impacts. These measures, which would be applied to all well pads, include the application of specific procedures identified in the 1992 GEIS for topsoil conservation and redistribution in agricultural districts. These procedures include stripping off and stockpiling topsoil during construction; protecting stockpiled topsoil from erosion and contamination; cutting well casings to a safe buffer depth of 4 feet below the ground surface; preparing areas before topsoil redistribution if compaction has occurred on-site; and redistributing the topsoil over the disturbed area of the former well pads during reclamation (Rumbach 2011).

7.9.4 Offsetting Mitigation

The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. Thus, a decline in the landscape quality that would result from development of a proposed well site could, at least partially, be ‘offset’ by the correction. An example of offsetting mitigation might be the removal

[505] Although substantial equipment and activity would be present at well sites during the construction and development phases, such equipment and activities are temporary. Once construction and well development is completed, some activities would cease and some equipment would be removed, and these are not considered to be decommissioning activities.

of an existing abandoned structure that is in disrepair (i.e., an ‘eyesore’) to offset impacts from the development of a well site within visual proximity to the same sensitive visual resource (NYSDEC 2000). Offsetting mitigation should be employed only when significant improvements in visually sensitive locations can be expected at a reasonable cost (NYSDEC 2000).

7.10 Noise Mitigation Measures[506]

Noise is best mitigated by increasing distance between the source and the receiver; the greater the distance the lower the noise 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.

7.10.1 Pad Siting Equipment, Layout and Operation

Many of the potential negative impacts of gas development depend on the location chosen for the well pad and the techniques used in constructing the access road and well site. Before a drilling permit can be issued, Department 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, Department staff will rely on Policy Guidance Document DEP-00-1, “Assessing and Mitigating Noise Impacts.”

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 Subsection 5.1.4.2, current regulations allow for a 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 recover the resource in the same area that could contain up to 16 single well pads.

[506] Section 7.10, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

With proper pad location and design, the adverse noise impacts could be significantly reduced. A multi-well pad provides a platform to extract gas over a wider area than the area exploited by a single vertical well. This provides an opportunity to locate the multi-well pad away from a noise receptor and in a location where there is intervening topography and vegetation, which can reduce the noise level at the receptor location to a level below that which might result from several single-well pads in close proximity to the receptor location.

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 fracturing water is also possible by reusing water for multiple fracturing jobs. In certain instances, it also may be economically viable to transport water via pipeline to a multi-well pad.

7.10.2 Access Road and Traffic Noise

As noted, high-volume hydraulic fracturing results in a greater number of heavy truck trips to the well pad compared to conventional drilling. Given the extensive trucking and associated noise involved with water transportation for high-volume hydraulic fracturing, attention should be given to the location of access road(s). Where appropriate, roads should be located as far as practicable from occupied structures and places of assembly. This would serve to protect noise receptors from noise impacts associated with trucking and road construction that could conflict with their property use.

Traffic noise mitigation measures may include modification of speed limits and restricting or prohibiting truck traffic on certain roads. Restricting truck use on a given roadway would reduce noise levels at nearby receptors, since trucks are louder than cars. However, displacing truck traffic from one roadway to another would shift noise impacts from one area to another. While reducing speeds may reduce noise levels, a reduction of at least 10 mph is needed to achieve a noticeable difference in noise level.

7.10.3 *Well Drilling and Hydraulic Fracturing*

As discussed in the 1992 GEIS (NYSDEC 1992), moderate to significant noise impacts may be experienced within 1,000 feet of a well site during the drilling phase. With the extended duration of drilling and other activities involved with multi-well pads, the Department will review the location of multi-well pads closer than 1,000 feet to occupied structures and places of assembly and determine what mitigation is necessary to minimize impacts.

Once the location and layout of a drilling site have been established and prior to the execution of the drilling project, noise modeling should be required using commercially available noise modeling software for any site located within 1,000 feet of a noise receptor. The software should be capable of simulating the three-dimensional outdoor propagation of sound from each noise source and account for sound wave divergence, atmospheric and ground sound absorption, and sound attenuation due to interceding barriers and topography. The effect of topography on noise propagation would be an important factor in the areas where drilling to access the Marcellus and Utica Shales would likely occur. The results of the modeling should be used by the applicant to evaluate noise levels that would be experienced at the nearest noise receptors and to develop mitigation measures for use in controlling noise levels generated during drilling and hydraulic fracturing of the well(s).

Examples of noise mitigation techniques that can be implemented as site-specific permit conditions include the following, as practicable:

- Requiring the measurement of ambient noise levels prior to beginning operations;
- Specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof;
- Placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors;
- Using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling;
- Limiting drill pipe cleaning (“hammering”) to certain hours;
- Running of casing during certain hours to minimize noise from elevator operation;

- Placing air relief lines and installing baffles or mufflers on lines;
- Limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.);
- Using higher or larger-diameter stacks for flare testing operations;
- Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition;
- Providing advance notification of the drilling schedule to nearby receptors;
- Placing conditions on air rotary drilling discharge pipe noise, including:
    - Orienting high-pressure discharge pipes away from noise receptors;
    - Having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point;
    - Having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges;
    - Shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or
    - Rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release;
- Using rubber hammer covers on the sledges when clearing drill pipe;
- Laying down pipe during daylight hours;
- Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors;
- Limiting hydraulic fracturing operations to a single well at a time;
- Employing electric pumps; and

- Installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature.

Many of these mitigation techniques have been successfully applied at wells drilled in New York

Photo 7.2 - Sound Barrier. Source: Ground Water Protection Council, Oklahoma City, OK and ALL Consulting, Tulsa OK, 2009 (New August 2011)

Source: Penn State Cooperative Extension

Photo 7.3 - Sound Barrier Installation (New August 2011)

Photo 7.4 - Sound Barrier Installation (New August 2011)

7.10.4 Conclusion

As discussed in the 1992 GEIS (NYSDEC 1992), temporary, short-term noise impacts may vary, based on the presence of topographic barriers (e.g., hills) or vegetative barriers (e.g., hills, trees, tall grass, shrubs). Drilling and hydraulic fracturing 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 the operation of trucks, backhoes, tractors, and cement mixers. During hydraulic fracturing, the primary source of noise is the multiple fracturing fluid pumps operating simultaneously. In most instances, the closest receptor is the residence of the owner of the property where the well is located, and the owner will have agreed to the disturbance by entering into a voluntary lease agreement with the well operator. However, this may not always be the case, due to compulsory integration and other circumstances. Noise impacts can be reduced, when necessary, at nearby receptors (regardless of lease status) by a combination of setbacks, site layout to take advantage of existing topography, implementation of noise barriers, and special permit conditions.

The 1992 GEIS (NYSDEC 1992) indicated that there were unavoidable adverse noise impacts for those living in 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 types of noise impacts associated with horizontal drilling with high-volume hydraulic fracturing have been found to be similar to those for vertical drilling, these findings are also applicable to horizontal drilling and high-volume hydraulic fracturing. The extended time period for horizontal drilling with high-volume hydraulic fracturing, while still temporary, makes the control of noise impacts essential. Since noise control is most effectively addressed during 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 need. The Department's guidance document DEP-00-01, "Assessing and Mitigating Noise Impacts," should be utilized along with a site plan and noise modeling (when the well pad is to be located within 1,000 feet of occupied structures or places of assembly) for this purpose. In addition, the applicant is encouraged to review any applicable local land use policy documents with the understanding that NYSDEC retains authority to regulate gas development (NTC 2011).

Supplementary permit conditions for high-volume hydraulic fracturing would include the following requirements to mitigate potential noise impacts:

- Unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property; and

- The well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS.

The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. 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 or places of assembly.

7.11 Transportation Mitigation Measures[507]

The transportation of water, hydraulic fracturing materials, and liquid wastes appears to account for well over 90% of all heavy truck traffic from a gas well over its productive life. Mitigating measures can help prevent, reduce or compensate for the potentially significant adverse impacts resulting from the increased transportation and road use related to vehicular traffic necessary for horizontal drilling and high-volume hydraulic fracturing. These are summarized by potential impact category as described in Section 6.11.

7.11.1 Mitigating Damage to Local Road Systems

As discussed in Section 6.11, the majority of impacts on roads would occur on local roads near the wells. The following measures would address impacts of increased transportation, particularly by heavy trucks, on local road systems.

7.11.1.1 Development of Transportation Plans, Baseline Surveys, and Traffic Studies

The Department would require, as part of any permit application, that the applicant submit a transportation plan. The transportation plan would identify the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be

[507] Section 7.11, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic. The transportation plan would also identify whether the operator has entered into a road use agreement or agreements with local governments and the condition of roads and bridges that are expected to be used by trucks directly and indirectly associated with the drilling operation. No permit should be issued until the Department and the NYSDOT are satisfied that the Transportation Plan is adequate to ensure that the traffic associated with the activity can be conducted safely and would reduce the impacts from truck traffic on local road systems to the maximum extent feasible.

It is important that the Transportation Plan evaluate pre-impact conditions so that any potential damages to roads and infrastructure can be fairly assessed. Establishing an accurate assessment of current conditions by conducting a baseline survey can be beneficial to both the local municipality and the operator; such baseline surveys should include information for local, state and interstate roads. State and interstate highways are surveyed annually and state secondary roads are surveyed every two years (NYSDOT 2010). However, local municipalities may not have the funds, equipment, or staff to survey local roads on a regular basis. Therefore, it would be the responsibility of the operator to conduct a baseline survey of local roads in accordance with methods described in the NYS traffic survey methods manual (NYSDOT 2010).

The results of a baseline survey of local road conditions should be combined with an assessment of the existing heavy truck traffic on the local roads and the relative amount of project-related traffic to develop a road condition study. This road condition study would be used to assess the proportion of the cost of road repairs that would be the responsibility of the operator. For example, if the road condition study concludes that the well operator would double the existing heavy truck traffic, and the road condition study indicates that a deterioration of pavement condition during the heavy traffic period of the project would occur, then the operator would be required to have an agreement in place to pay for the work required to repair or prevent the road deterioration.

7.11.1.2 Municipal Control over Local Road Systems

Under NYS highway vehicle traffic laws, local municipalities retain control over their roads, and as such, can implement measures to prevent or minimize transportation impacts. For example, NYS Vehicle and Traffic Law § 1640(a)(5) provides that, "The legislative body of any city or village, with respect to highways … in such city or village … may by local law, ordinance, order, rule or regulation … exclude trucks, commercial vehicles, tractors, tractor-trailer combinations, [and] tractor-semitrailer combinations from highways specified by such legislative body." Part 10 of this same section allows legislative bodies of a city or village to "establish a system of truck routes upon which all trucks, tractors and tractor-trailer combinations, having a gross weight in excess of ten thousand pounds are permitted to travel and operate and excluding such vehicles and combinations from all highways except those which constitute such truck route system." Part 20 of this same section allows for the establishment of weight, height, length, and width criteria, for which vehicles in excess of such standards may be excluded from highways or the setting of limits on hours of operation of such vehicles on particular city or village highways or segments of such highways. Essentially, NYS Vehicle and Traffic Law §1640(a) (5), (10), and (20) allow local governments to establish regulations pertaining to the use of city or town highways by trucks, tractor trailers, etc., and to exclude such vehicles from use of city or town highways as may be delineated by the local legislative body.

In addition to city and village ordinances or rules that may govern the use of highways within a city or village, NYS Vehicle and Traffic Law § 1650(4)(a) provides that "the county superintendent of highways of a county with respect to county roads in such county, may by order, rule or regulation: … exclude trucks, commercial vehicles, tractors, etc. in excess of designated weight, length, height and width from county highways, or set limits of hours of operation for such vehicles." This is essentially the same legislative authority given to cities and villages in Vehicle and Traffic Law §1640, except this pertains to counties. The same is true of Vehicle and Traffic Law § 1660(a) (10), (11), (17), and (28), which allow for the same exclusion of trucks, tractors, tractor-trailers, etc., as provided in the previous Articles, except that this section pertains to the authority of a town's legislative body. In addition, Town Law § 130 (7) allows for a town board, after a public hearing, to enact, amend, or repeal ordinances, rules, and regulations pertaining to the use of streets, highways, sidewalks, and public places by pedestrians, motor and other vehicles, and restrict parking of all vehicles therein.

As noted above, municipalities would be notified of applications that indicate that high-volume hydraulic fracturing is planned. In addition, municipalities should monitor the Department's Web site for additional information regarding gas development in their areas. In light of their substantial authority over access to local roads, local governments (county, town, and village) would likely be proactive in exercising their authority under NYS highway vehicle traffic laws. This would include requiring a local road use agreement (discussed below), taking into account the required road condition study, which would provide the basis for potentially assessing fees for maintenance and improvements to local roads.

7.11.1.3 Road Use Agreements

As stated above in Section 7.11.1.2, local governments have the authority to enter into road use agreements with well operators, which identify where an operator may or may not drive trucks, weight limits, times of day, etc. Therefore, the owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible.

The road use agreement would be the primary mechanism by which local governments can hold well operators accountable for damages and repairs to roads, bridges, and drainage structures that may be impacted by their excess use. When utilized appropriately, this mechanism has proven effective with wind developers in New York State.

Measures that should be part of a road use agreement or trucking plan, as appropriate, include:

- Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10);

- Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20);
- 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, as may be reimbursable pursuant to ECL §23-0303(3);
- Advance public notice of any necessary detours or road/lane closures;
- 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 would re-emphasize that issuance of a well permit does not provide relief from any local requirements authorized by or enacted pursuant to the Vehicle and Traffic Law. Such permit conditions would also require the following:

1. Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality; and
2. The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally.

When there is no agreement, the applicant should nevertheless be guided by Environmental Conservation Law (ECL) § 23-0303(2), which provides that "this article shall supersede all local laws or ordinances relating to the regulation of the oil, gas and solution mining industries; but shall not supersede local government jurisdiction over local roads or the rights of local governments under the real property tax law." This gives local municipalities the authority to designate and enforce vehicle and traffic laws pertaining to the use of local roads by motor vehicles, including trucks engaged in activities connected to gas drilling.

7.11.1.4 Reimbursement for Costs Associated with Local Road Work

Under Highway Law § 136 (2), "a county superintendent shall establish regulations governing the issuance of highway work permits, including the fees to be charged therefor, a system of deposits of money or bonds guaranteeing the performance of the work and requirements of insurance to protect the interests of the county during performance of the work pursuant to a highway work permit." It is through this legislation that a county is able to financially mitigate impacts on roads and highways caused by roadwork associated with well development, but this law would not provide for payments for damages to roads from excess use.

7.11.2 Mitigating Incremental Damage to the State System of Roads

Truck traffic on the interstate highway system and other regional roads would also suffer wear and tear due to the added traffic associated with horizontal drilling and high-volume hydraulic fracturing. Given the potentially dramatic increase in the number of large trucks and their distribution in the high-volume hydraulic fracturing region, a significant expansion in truck inspection requirements would be expected. This would require close coordination with other organizations, including local municipalities and the State Police. There is likely to be a substantial increase in oversize/overweight permitting requests, which may require additional permit staff at NYSDOT to handle these requests.

In addition, the installation of associated infrastructure, such as gas and water pipeline expansions and extensions, would require highway work permits, resulting in additional management, oversight, and inspection services by NYSDOT staff. Local municipalities would also likely see a sharp increase in their transportation-related staffing needs and budgets. These additional needs would include staff to carry out or oversee road condition surveys, traffic counts (or studies), local road and detour postings, execution of Road Use or Excess Maintenance agreements, and other activities. Personnel and resources would be necessary to monitor road conditions, manage and enforce agreements, and provide regulatory and emergency services.

State permit regulations could be developed that assess mitigation fees as a permit condition to defray some of these new costs. Other state revenue sources and mechanisms for collecting fees to address damages and wear to the state system of roads would include contributions to the

Highway and Bridge Conservation Fund, the collection of heavy vehicle registration fees, tolls and other highway use taxes, petroleum business taxes, and motor fuel taxes.

However, the revenue that is currently collected to compensate the state for damages to the state system of roads is deemed by NYSDOT to be insufficient for addressing required roadway maintenance. Thus, the added burden of the potential adverse impacts on the state system of roads associated with the proposed development of natural gas reserves using high-volume hydraulic fracturing may pose an additional financial burden on the state, which would be considered an adverse impact that may not be fully mitigated.

7.11.3 Mitigating Operational and Safety Impacts on Road Systems

Where appropriate, site-specific mitigation of safety impacts would be applied to each applicant's permit. These would include, but are not limited to, the following:

- Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff);
- Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments;
- Providing industry-specific training to first responders to prepare for potential accidents;
- Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion;
- Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays; and
- Avoiding hours and routes used by school buses.

Due to the generic nature of this analysis and the unknown road segments where these heavy- and light-duty trucks would travel, it is not possible at this time to identify specific operational and safety impacts, nor is it possible to identify operational or safety mitigation strategies for specific locations.

As noted in Section 7.8 (Socioeconomic Mitigation Measures), through its permitting process, the Department will monitor the pace and concentration of development throughout the state to mitigate adverse impacts at the local and regional levels. The Department will consult with local jurisdictions, as well as applicants, to reconcile the timing of development with the needs of the communities. Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified.

7.11.4 Other Transportation Mitigation Measures

High-volume hydraulic fracturing is a relatively new and evolving technology, and the industry is exploring a variety of alternatives that could substantially reduce the need for and impacts of heavy trucks. Potential future alternatives include innovative methods of hydraulic fracturing such as the use of natural gas gels, which might entirely eliminate the need for trucking water to well sites; and innovative water supply systems such as the construction of water wells serving multiple well pads via a piping system, which would reduce the need for trucking water to well sites. On-site treatment and disposition of wastes is another potential alternative that could reduce the need for trucking. For example, Chesapeake Energy has eliminated the trucking of wastes from well sites through on-site treatment and disposition in the Marcellus Shale area in Pennsylvania. If this practice were extended to other gas development companies operating in other areas with gas-producing shales, such as the Marcellus and Utica Shales in New York, it would result in similar substantial reductions in the need for trucking.

7.11.5 Mitigating Impacts from the Transportation of Hazardous Materials

Preliminary data has been provided to the Department outlining the typical components of the fracturing fluids to be used in the state. The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process.

Specific information on the transportation of these materials is presented in Section 5.5. In summary, all fracturing fluids and additives are transported in “DOT-approved” trucks or containers. The federal Hazardous Material Transportation Act (HMTA) and Hazardous Materials Transportation Uniform Safety Act (HMTUSA) are the basis for federal hazardous materials transportation law and give regulatory authority to the Secretary of the USDOT to enforce the regulations. These extensive regulations address the potential concerns involved in transporting hazardous fracturing additives, including loading, unloading, shipping, and packaging. These regulations are enforced by the USDOT agencies and, when followed and enforced, can mitigate risks.

The NYSDOT requires all registrants of commercial motor vehicles to obtain a USDOT number and has adopted many USDOT regulations that apply to interstate highway transportation. There are minor exceptions to these federal regulations; however, the exemptions do not directly relate to the objectives of this review. New York State regulations include motor vehicle carriers that operate solely on an intrastate basis. These carriers must comply with 17 NYCRR Part 820 (as described in Section 8.1.2.2) in addition to the applicable requirements and regulations of the Vehicle and Traffic Law and the NYS Department of Motor Vehicles. This includes regulations requiring carriers to obtain authorization to transport hazardous materials from the USDOT or NYSDOT Commissioner.

Municipalities may require trucks transporting hazardous materials to travel on designated routes, in accordance with a road use agreement; however, this would not eliminate entirely the potential for an accidental release. Depending on its size and location, a spill could have a significant adverse impact on the local community. First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need, and transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials.

7.11.6 Mitigating Impacts on Rail and Air Travel

The potential impacts on the rail industry would be positive. Growth in haulage, and consequently in revenues and employment, would likely occur. However, as evidenced in Pennsylvania, infrastructure would need to be improved (e.g., tracks extended, rail yards expanded, new sidings/offloading facilities provided at appropriate locations, etc.). The potential adverse impacts of increased traffic on the existing rail facilities could be mitigated by the construction of new facilities. The majority of financing for improvements is provided by the rail companies or through partnerships and investment partnerships with major users. At the same time, there can be a significant demand for public investment as well. The variety of financing and investment instruments can be drawn from Pennsylvania's experience, for example SEDA-COG Joint Railway Authority, which financed roughly $16 million of projects in six counties through a combination of USDOT grants ($10 million), a $3.8 million PennDOT grant, and a $2.2 million public-private partnership.

7.12 Community Character Mitigation Measures[508]

Local and regional planning documents are important in defining a community's character and are the principal way of managing change within a community. These plans are used to guide development and provide direction for land development regulations (e.g., zoning, noise control, and subdivision ordinances) and designation of special districts for economic development, historic preservation, and other reasons.

As discussed in Chapter 3, the Department would require the applicant to prepare an EAF Addendum for gathering and compiling the information needed to evaluate high-volume hydraulic fracturing projects (≥300,000 gallons) in the context of this SGEIS and its Findings Statement, and to identify the required site-specific mitigation measures.

The EAF Addendum would be required as follows:

- With the application to drill the first well on a pad constructed for high-volume hydraulic fracturing, regardless of whether the well is vertical or horizontal;
- With the applications to drill subsequent wells for high-volume hydraulic fracturing on the pad if any of the information changes; and
- Prior to high-volume re-fracturing of an existing well.

[508] Section 7.12, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011 and was adapted by the Department.

The EAF Addendum would require the applicant to identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws, regulations, plans, or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s).

Where the project sponsor indicates that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans, or policies, or is not covered by such local land use laws, regulations, plans, or policies, no further review of local land use laws and policies would be required.

In cases where a project sponsor indicates that all or part of their proposed application is inconsistent with local land use laws, regulations, plans, or policies, or where the potentially impacted local government advises the Department that it believes the application is inconsistent with such laws, regulations, plans, or policies, the Department intends to request additional information in the permit application to determine whether this inconsistency raises significant adverse environmental impacts that have not been addressed in the SGEIS.

The Department notes, that recently the New York Court of Appeals in *Matter of Wallach v. Town of Dryden et al.*, 23 N.Y.3d 728 (2014), found that ECL Section 23-0303(2) does not preempt communities with adopted zoning laws from entirely prohibiting the use of land for high-volume hydraulic fracturing. In that decision, the Court noted that: "Manifestly, Dryden and Middlefield engaged in a reasonable exercise of their zoning authority … when they adopted local laws clarifying that oil and gas extraction and production were not permissible uses in any zoning districts. The Towns both studied the issue and acted within their home rule powers in determining that gas drilling would permanently alter and adversely affect the deliberately cultivated, small-town character of their communities."

In addition, a supplemental site-specific review is required when an applicant proposes to construct a well pad on a farm within an Agricultural District when the proposed disturbance is larger than 2.5 acres. In such cases, the Department would consult with the DAM to develop additional permit conditions, best management practice requirements, and reclamation guidelines to be followed.

Examples of the proposed Agricultural District requirements include but are not limited to the following:

- Decompaction and deep ripping of disturbed areas prior to topsoil replacement;
- Removal of construction debris from the site;
- No mixing of cuttings with topsoil;
- Removal of spent drilling muds from active agricultural fields;
- Location of well pads/access roads along field edges and in nonagricultural areas (where practicable);
- Removal of excess subsoil and rock from the site; and
- Fencing of the site when drilling is located in active pasture areas to prevent livestock access.

Implementation of these measures would lead to successful reestablishment of agricultural lands when well pads are no longer productive.

The socioeconomic, visual, noise, and transportation impacts discussed in Sections 6.8, 6.9, 6.10, and 6.11, respectively, also impact community character. To the extent that these impacts are mitigated as discussed in Sections 7.8 (Socioeconomic), 7.9 (Visual), 7.10 (Noise), and 7.11 (Transportation), impacts on community character would also be reduced to the extent that the impacts are related to community character.

7.13 Emergency Response Plan

There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities. An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site. The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets. The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud. The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department.

The ERP, at a minimum, would also include the following elements:

- Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;
- Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;
- Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;
- Identification and evaluation of potential release, fire and explosion hazards;
- Description of release, fire, and explosion prevention procedures and equipment;
- Implementation plans for shut down, containment and disposal;
- Site training, exercises, drills, and meeting logs; and
- Security measures, including signage, lighting, fencing and supervision.

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Chapter 8

Permit Process and Regulatory Coordination

Final

Supplemental Generic Environmental Impact Statement

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Chapter 8 – Permit Process and Regulatory Coordination

FIGURES

TABLES

Chapter 8 PERMIT PROCESS AND REGULATORY COORDINATION

8.1 Interagency Coordination

Table 8.1, together with Table 15.1 of the 1992 GEIS, shows the spectrum of government authorities that oversee various aspects of well drilling and hydraulic fracturing. The 1992 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 revised draft SGEIS identified the following additional agencies that were not previously listed and have been added to Table 8.1:

- NYSDOH;
- USDOT and NYSDOT;
- Office of Parks, Recreation and Historic Preservation (OPRHP);
- NYCDEP; and
- SRBC and DRBC.

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 the Department'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 supersedure of all other laws enacted by local governments or agencies concerning the imposition of a fee on activities regulated by ECL 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 2,000 feet of a municipal water supply well; and

- 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 revised draft SGEIS, the Department proposes that 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 at a well pad within 500 feet of a principal aquifer (to be re-evaluated two years after issuance of the first permit for high-volume hydraulic fracturing);

- Issuance of a permit to drill when high-volume hydraulic fracturing is proposed on a well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond;

- 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 NFRM as described in Chapter 7;

- Any proposed water withdrawal from a pond or lake;

- Any proposed ground water withdrawal within 500 feet of a private well;

- Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland; and

- Issuance of a permit to drill any well subject to ECL 23 whose location is determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.

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

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

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

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

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.

8.1.1.3 Local Government Notification

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. The Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, using a continuously updated database of local government officials and an electronic notification system that would both be developed for this purpose.

8.1.1.4 Road-Use Agreements

The Department strongly encourages operators to reach road use agreements with governing local authorities. The issuance of a permit to drill does not relieve the operator of the responsibility to comply with any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Additional information about road infrastructure and traffic impacts is provided in Sections 6.11 and 7.13.

8.1.1.5 Local Planning Documents

The Department's exclusive authority to issue well permits supersedes local government authority relative to well siting. However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the

Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.

Applicants for permits to drill are already required to identify whether any additional state, local or federal permits or approvals are required for their projects. Therefore, in cases where an applicant indicates that all or part of their proposed project is inconsistent with local land use laws, regulations, plans or policies, or where the potentially impacted local government advises the Department that it believes the application is inconsistent with such laws, regulations, plans or policies, the Department would, at the time of permit application, request additional information so that it can consider whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts.

8.1.1.6 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. The Department proposes that county health departments retain responsibility for initial response to most water well complaints, referring them to the Department when causes other than those related to drilling 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 Section 8.1.2.1), no State agencies other than the Department are listed in GEIS Table 15.1. The NYSDOH, NYSDOT, along with the Office of Parks, Recreation and Historic Preservation, are listed in Table 8.1 and will be involved as follows:

- *NYSDOH:* Potential future and ongoing involvement in review of NORM issues and assistance to county health departments regarding water well investigations and complaints;

- *NYSDOT*: Not directly involved in well permit reviews, but has regulations regarding intrastate transportation of hazardous chemicals found in hydraulic fracturing additives and may advise the Department regarding the required transportation plans and road condition assessments; and

- *OPRHP:* In addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants.

8.1.2.1 Public Service Commission

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 the Department 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 Department 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 early reported anticipated success rates of one hundred percent in 2009, it had 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. However, as reported in late 2010 and described below, not all Marcellus Shale wells drilled in neighboring Pennsylvania have proved to be economical when drilled beyond what some have termed the "line of death."[509]

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[509] Citizens Voice, Wilkes-Barre, PA., Drillers Take Another Chance in Columbia County, May 9, 2011 http://energy.wilkes.edu/pages/106.asp?item=341.

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;[510] 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,"[511] 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 would 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. 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.

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[510] Article VII does not however supplant the need to obtain property rights from the State for a transmission line project that proposes to cross State-owned land. PSC has no authority, express or implied, to grant land easements, licenses, franchises, revocable consents, or permits to use State land. The Department, therefore, retains the authority to grant or deny access to State lands under its jurisdiction.

[511] http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf.

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 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;
- 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 8.2, 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. The Department'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 Department is responsible for administering federally delegated permitting programs involving air and water resources. For all other pipelines regulated by the PSC, the Department's jurisdiction is limited to the permitting of certain federally delegated programs involving air and water resources. Nevertheless, in all instances, the Department 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 8.2 - Intrastate Pipeline Regulation[512]

Pipeline Type	Department	PSC
Gathering <125 psig	Siting jurisdiction only in environmentally sensitive areas where Department 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.
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.		

512 Adapted from the NYSDEC GEIS 1992.

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 and the same appears to be true for potential drilling under the SGEIS as not all wells drilled will be productive. More than one or two wells on the same pad may need to be drilled to prove economical production prior to an operator making a commitment to invest in and build a pipeline. Actual drilling at any given location is the only way to know if a given area will be productive, especially in the fringe of any predetermined productive fairways. In 2010, it was reported that Encana Oil & Gas USA Inc. drilled several unsuccessful Marcellus Shale wells in Luzerne County, Pennsylvania and that "there wasn't enough gas in either to be marketable."[513]

Consequently, the typical procedure of drilling wells, testing wells by flaring and then constructing gathering lines may or may not be suited for the development of the Marcellus Shale and other low permeability reservoirs depending upon the location of proposed wells and the establishment of productive fairways through drilling experience. In 2009, the success rate of horizontally drilled and hydraulically fractured Marcellus Shale wells in neighboring Pennsylvania and West Virginia, as reported by three companies, was one hundred percent for 44 wells drilled.[514] This early rate of success was apparently due primarily to the fact that the Marcellus Shale reservoir in location-specific fairways appears to contain natural gas in sufficient quantities which can be produced economically using horizontal drilling and high-volume hydraulic fracturing technology. However, as noted above, some Marcellus Shale wells subsequently drilled in Pennsylvania apparently using the same technology did not prove successful. It is highly unlikely that an operator in New York would make a substantial investment in a pipeline ahead of completing a well unless drilling is conducted in a known productive fairway and there is a near guarantee of finding gas in suitable quantities and at viable flow rates.

In addition, the Marcellus Shale formation in some areas is known to have 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 in these areas could require that the well be flowed back and gas produced immediately after the well has been fractured and completed, otherwise the formation may be

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[513] Citizens Voice, Despite Encana's Exit, Other Companies Stay Put, November 20, 2010 http://citizensvoice.com/news/despite-encana-s-exit-other-companies-stay-put-1.1066540#axzz1NZF239wB.

[514] Chesapeake Energy Corp., Fortuna Energy Inc., Seneca Resources Corp.

damaged and the well may cease to be economically productive. However, clay stabilizer additives are available for injection during hydraulic fracturing operations which help inhibit the swelling of clays present in the target formation. In addition to possibly 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 referred to as a 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 has also been used in Pennsylvania on a limited basis. 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.[515] While it is not known if or when LPG hydraulic fracturing will be proposed in New York, having gathering infrastructure in place may be an important factor in realizing the advantages of this technology. Instead of LPG/natural gas separation equipment being required at individual well pads during flowback, an in-place gas production pipeline would allow and facilitate the siting of centralized separation equipment that could service a number of well pads thereby providing for a more efficient LPG hydraulic fracturing operation.

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. 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, after drilling experience is gained, to certify and build pipelines in advance of well drilling targeting the Marcellus Shale and other low-permeability gas reservoirs in known productive fairways.

[515] Smith M, 2008, p. 4.

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 Department, 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 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 Department 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:

- the need for the facility;
- the nature of the probable environmental impact;
- the extent to which the facility minimizes adverse environmental impact, given environmental and other pertinent considerations;
- that the facility location will not pose undue hazard to persons or property along the line;
- that the location conforms with applicable State and local laws; and
- that 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 Department 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 the Department 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.[516] The

[516] NYSDPS, 2006

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 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. DPS 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.

8.1.2.2 NYS Department of Transportation

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 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.

NYSDOT would also have an advisory role with respect to the transportation plans and road condition assessments that operators will be required to submit.

8.1.3 Federal

The United States Department of Transportation is the only newly listed federal agency in Table 8.1. 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.

8.1.3.1 U.S. Department of Transportation

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).

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); and
- 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); and
- 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.

8.1.3.2 Occupational Safety and Health Administration – Material Safety Data Sheets

The Occupational Safety and Health Administration (OSHA) is part of the United States Department of Labor, and was created by Congress under the Occupational Safety and Health Act of 1970 to ensure safe and healthful working conditions by setting and enforcing standards and by providing training, outreach, education and assistance.[517]

In order to ensure chemical safety in the workplace, information must be available about the identities and hazards of chemicals. OSHA's Hazard Communication Standard, 29 CFR §1910.1200,[518] requires the development and dissemination of such information and requires that chemical manufacturers and importers evaluate the hazards of the chemicals they produce or import, prepare labels and Material Safety Data Sheets (MSDSs) to convey the hazard

517 OSHA, http://www.osha.gov/about.html.

518 Available at http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=10099.

information, and train workers to handle chemicals appropriately. This standard also requires all employers to have MSDSs in their workplaces for each hazardous chemical they use.

The requirements pertaining to MSDSs are described in 29 CFR §1910.1200(g), and include the following information:

- The identity used on the label;
- The chemical[519] and common name(s)[520] of the hazardous chemical[521] ingredients, except as provided for in §1910.1200(i) regarding trade secrets;
- Physical and chemical characteristics of the hazardous chemical(s);
- Physical hazards of the hazardous chemical(s), including the potential for fire, explosion and reactivity;
- Health hazards of the hazardous chemical(s);
- Primary route(s) of entry;
- The OSHA permissible exposure limit, ACGIH Threshold Limit Value, and any other exposure limit used or recommended by the chemical manufacturer, importer or employer preparing the MSDS;
- Whether the hazardous chemical(s) is listed in the National Toxicology Program (NTP) Annual Report on Carcinogens (latest edition) or has been found to be a potential carcinogen in the International Agency for Research on Cancer (IARC) Monographs (latest editions), or by OSHA;

[519] 29 CFR §1910.1200(c) defines "chemical name" as "the scientific designation of a chemical in accordance with the nomenclature system developed by the International Union or Pure and Applied Chemistry (IUPAC) or the Chemical Abstracts Service (CAS) rules of nomenclature, or a name which will clearly identify the chemical for the purpose of conducting a hazard evaluation."

[520] 29 CFR §1910.1200(c) defines "common name" as "any designation or identification such as code name, code number, trade name, brand name or generic name used to identify a chemical other than by its chemical name."

[521] 29 CFR §1910.1200(c) defines "hazardous chemical" as "any chemical which is a physical hazard or a health hazard," and further defines "physical hazard" and "health hazard" respectively as follows: "Physical hazard means a chemical for which there is scientifically valid evidence that it is a combustible liquid, a compressed gas, explosive, flammable, an organic peroxide, an oxidizer, pyrophoric, unstable (reactive) or water-reactive"; "Health hazard means a chemical for which there is statistically significant evidence based on at least one study conducted in accordance with established scientific principles that acute or chronic health effects may occur in exposed employees. The term 'health hazard' includes chemicals which are carcinogens, toxic or highly toxic agents, reproductive toxins, irritants, corrosives, sensitizers, hepatoxins, nephrotoxins, neurotoxins, agents which act on the hematopoietic system, and agents which damage the lungs, skin, eyes, or mucous membranes."

- Any generally applicable precautions for safe handling and use including appropriate hygienic practices, measures during repair and maintenance of contaminated equipment, and procedures for clean-up of spills and leaks;

- Any generally applicable control measures such as appropriate engineering controls, work practices, or personal protective equipment;

- Emergency and first aid procedures;

- Date of preparation of the MSDS or the last change to it; and

- Name, address and telephone number of the chemical manufacturer, importer, employer or other responsible party preparing or distributing the MSDS, who can provide additional information on the hazardous chemical and appropriate emergency procedures, if necessary.

MSDSs and Trade Secrets

29 CFR §1910.1200(i) sets forth an exception from disclosure in the MSDS of the specific chemical identity, including the chemical name and other specific identification of a hazardous chemical, if such information is considered to be trade secret. This exception however is conditioned on the following:

- that the claim of trade secrecy can be supported;

- that the MSDS discloses information regarding the properties and effects of the hazardous chemical;

- that the MSDS indicates the specific chemical identity is being withheld as a trade secret; and

- that the specific chemical identity is made available to health professionals, employees, and designated representatives in accordance with the provisions of 29 CFR §1910.1200(i)(3) and (4) which discuss emergency and non-emergency situations.

8.1.3.3 EPA's Mandatory Reporting of Greenhouse Gases

In October 2009, the United States EPA published 40 CFR §98, referred to as the Greenhouse Gas (GHG) Reporting Program, which mandates the monitoring and reporting of GHG emissions from certain source categories in the United States. The nationwide emission data collected under the program will provide a better understanding of the relative GHG emissions of specific industries and of individual facilities within those industries, as well as better understanding of the factors that influence GHG emissions rates and actions facilities could take to reduce emissions.[522]

The GHG reporting requirements for facilities that contain petroleum and natural gas systems were finalized in November 2010 as Subpart W of 40 CFR §98. Under Subpart W, facilities that emit 25,000 metric tons or more of CO_2 equivalent[523] per year in aggregated emissions from all sources are required to report annual GHG emission to EPA. More specifically, petroleum and natural gas facilities that meet or exceed the reporting threshold are required to report annual methane (CH_4) and carbon dioxide (CO_2) emissions from equipment leaks and venting, and emissions of CO_2, CH_4, and nitrous oxide (N_2O) from flaring, onshore production stationary and portable combustion emission, and combustion emissions from stationary equipment involved in natural gas distribution.[524]

The rule requires data collection to begin on January 1, 2011 and that reports be submitted annually by March 31st, for the GHG emissions from the previous calendar year.

Onshore Petroleum and Natural Gas Production Sector

For monitoring and reporting purposes, Subpart W divides the petroleum and natural gas systems source category into seven segments including: onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG)

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[522] USEPA, August 2010.

[523] CO_2 equivalent is defined by EPA as a metric measure used to compare the emissions from various GHGs based upon their global warming potential (GWP), which is the cumulative radiative forcing effects of a gas over a specified time horizon resulting from the emission of a unit mass of gas relative to a reference gas.

[524] USEPA, Fact Sheet for Subpart W, November 2010.

storage and LNG import and export, and natural gas distribution. 40 CFR §98.230(a)(2) defines onshore petroleum and natural gas production to mean:

> "all equipment on a well pad or associated with a well pad (including compressors, generators, or storage facilities), and portable non-self-propelled equipment on a well pad or associated with a well pad (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate)."

Facility Definition for Onshore Petroleum and Natural Gas Production

Reporting under 40 CFR §98 is at the facility level, however due to the unique characteristics of onshore petroleum and natural gas production, the definition of "facility" for this industry segment under Subpart W is distinct from that used for other segments throughout the GHG Reporting Program. 40 CFR §98.238 defines an onshore petroleum and natural gas production facility as:

> "all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 enhanced oil recovery (EOR) operations that are under common ownership or common control included leased, rented, and contracted activities by an onshore petroleum and natural gas production operator and that are located in a single hydrocarbon basin as defined in §98.238.[525] Where a person or entity owns or operators more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

525 40 CFR §98.238 defines "basin" as "geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-DSD Geologic Provinces code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) and the Alaska Geological Province Boundary Map, Compiled by the American association of Petroleum Geologists committee on Statistics of Drilling in Cooperation with the USGS, 1978."

GHGs to Report

Facilities assessing their applicability in the onshore petroleum and natural gas production segment must only include emissions from equipment, as specified in 40 CFR 98.232(c) and discussed below, to determine if they exceed the 25,000 metric ton CO_2 equivalent threshold and thus are required to report their GHG emissions to EPA.[526]

§98.232(c) specifies that onshore petroleum and natural gas production facilities report CO_2, CH_4, and N_2O emissions from only the following source types:

- Natural gas pneumatic device venting;
- Natural gas driven pneumatic pump venting;
- Well venting for liquids unloading;
- Gas well venting during well completions without hydraulic fracturing;
- Gas well venting during well completions with hydraulic fracturing;
- Gas well venting during well workovers without hydraulic fracturing;
- Gas well venting during well workovers with hydraulic fracturing;
- Flare stack emissions;
- Storage tanks vented emissions from producted hydrocarbons;
- Reciprocating compressor rod packing venting;
- Well testing venting and flaring;
- Associated gas venting and flaring from produced hydrocarbons;
- Dehydrator vents;
- EOR injection pump blowdown;
- Acid gas removal vents;

[526] Federal Register, November 30, 2010, p. 77462.

- EOR hydrocarbon liquids dissolved CO_2;
- Centrifugal compressor venting;
- Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and
- Stationary and portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at on onshore production well pad. The following equipment is listed within the rule as integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment; workover equipment; natural gas dehydrators; natural gas compressors; electrical generators; steam boilers; and process heaters.

GHG Emissions Calculations, Monitoring and Quality Assurance

40 CFR §98.233 prescribes the use of specific equations and methodologies for calculating GHG emissions from each of the source types listed above. The GHG calculation methodologies used in the rule generally include the use of engineering estimates, emissions modeling software, and emission factors, or when other methods are not feasible, direct measurement of emissions.[527] In some cases, the rule allows reporters the flexibility to choose from more than one method for calculating emissions from a specific source type; however, reporters must keep record in their monitoring plans as outlined in 40 CFR 98.3(g).[528]

Also, for specified time periods during the 2011 data collection year, reporters may use best available monitoring methods (BAMM) for certain emission sources in lieu of the monitoring methods prescribed in §98.233. This is intended to give reporters flexibility as they revise procedures and contractual agreements during early implementation of the rule.[529]

40 CFR §98.234 mandates that the GHG emissions data be quality assured as applicable and prescribes the use of specific methods to conduct leak detection of equipment leaks, procedures to operate and calibrate flow meters, composition analyzers and pressure gages used to measure quantities, and conditions and procedures related to the use of calibrated bags, and high volume

[527] USEPA Fact Sheet for Subpart W, November 2010.

[528] Federal Register. November 30, 2010, p. 74462.

[529] Federal Register. November 30, 2010, p. 74462.

samplers to measure emissions. Section 98.235 prescribes procedures for estimating missing data.

Data Recordkeeping and Reporting Requirements

Title 40 CFR §98.3(c) specifies general recordkeeping and reporting requirements that all facilities required to report under the rule must follow. For example, all reporters must:

- Retain all required records for at least 5 years;
- Keep records in an electronic or hard-copy format that is suitable for expeditious inspection and review;
- Make required records available to the EPA Administrator upon request;
- List all units, operations, processes and activities for which GHG emissions were calculated;
- Provide the data used to calculate the GHG emissions for each unit, operation, process and activity, categorized by fuel or material type;
- Document the process used to collect the necessary data for GHG calculations;
- Document the GHG emissions factors, calculations and methods used;
- Document any procedural changes to the GHG accounting methods and any changes in the instrumentation critical to GHG emissions calculations; and
- Provide a written quality assurance performance plan which includes the maintenance and repair of all continuous monitoring systems, flowmeters and other instrumentation.

40 CFR §98.236 specifies additional reporting requirements that are specific to the Petroleum and Natural Gas Systems covered under Subpart W.

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.

On May 6, 2010 the DRBC announced that it would draft regulations necessary to protect the water resources of the DRB during natural gas development. The drilling pad, accompanying facilities, and locations of water withdrawals were identified as part of the natural gas extraction project and subject to regulation by the DRBC. A draft rule was published in December 2010 and comments were accepted until April 15, 2011. There is no projected date or deadline for the adoption of rule changes.

8.2 Intra-Department

8.2.1 Well Permit Review Process

The Division of Mineral Resources (DMN) would 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 Division of Water would assist in this review if the applicant proposes to discharge either flowback water or production brine to a POTW. The Division of Fish, Wildlife and Marine Resources (DFWMR) would have an advisory role regarding invasive species control, and would assist in the review of site disturbance in Forest and Grassland Focus Areas. The Division of Air Resources would have an advisory role with respect to applicability of various air quality regulations and effectiveness of proposed emission control measures. When a site-specific SEQRA review is required, DMN would be assisted by other appropriate Department programs, depending on the reason that site-specific review is required and the subject matter of the review. The Division of Materials Management (DMM) would review applications for beneficial use of production brine in road-spreading projects.

8.2.1.1 Required Hydraulic Fracturing Additive Information

As set forth in Chapter 5, NYSDOH reviewed information on 322 unique chemicals present in 235 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 Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility 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 sets forth a water well testing protocol using indicators that are independent of specific additive chemistry.

For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5. Additionally, the anticipated volume of each additive product proposed for use would be required as part of the EAF Addendum. Beyond providing information about the quantity of each additive product to be utilized, this requirement informs the Department of the approximate quantity of each additive product that would be on-site for each high-volume hydraulic fracturing operation.

The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.

Finally, the Department proposes to require that the application materials (i) document the applicant's evaluation of available alternatives for the proposed additive products that are efficacious but which exhibit reduced aquatic toxicity and pose less risk to water resources and the environment and (ii) contain a statement that the applicant will utilize such alternatives, unless it demonstrates to DMN's satisfaction that they are not equally effective or feasible. The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system and (5) feasibility of implementing the alternative.

In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report[530] which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.

The Department has the authority to require, at any time, the disclosure of any additional additive product composition information it deems necessary to ensure that environmental protection and public health and safe drinking water objectives are met, or to respond to an environmental or public health and safety concern. This authority includes the ability to require the disclosure of information considered to be trade secret, so long as such information is handled in accordance with the New York State Public Officer's Law, POL§89(5), and the Department's Records Access Regulations, 6 NYCRR §616.7.

In accordance with the discussion in Chapter 7 regarding Publicly Owned Treatment Works (POTWs), the Department proposes to require the disclosure of additional additive composition information as part of any headworks analysis used to determine whether a particular treatment facility can accept flowback or production brine from wells permitted pursuant to this Supplement, or whether a modification to the POTW's SPDES permit is necessary prior to any acceptance of such fluids. This disclosure however, would be handled separately from the application for permit to drill, as the evaluation of headworks analyses and any necessary SPDES permit modifications would be handled through existing Department processes.

Public Disclosure of Additive Information

Although the Department must handle information which is sufficiently justified as trade secret in accordance with existing law and regulation as previously discussed, the Department considers MSDSs to be public information ineligible for exception from disclosure as trade secrets. Therefore, the Department proposes to provide a listing of high-volume hydraulic fracturing additive product names and links to the associated product MSDSs on an individual well basis on its website. This would provide the public with a resource, beyond the Freedom of

[530] The Well Drilling and Completion Report Form is available on the Department's website at http://www.dec.ny.gov/docs/materials_minerals_pdf/comp_rpt.pdf .

Information Law, for obtaining information about the additives utilized in high-volume hydraulic fracturing operations in New York, and it would provide the natural gas industry with a resource for determining if a particular product MSDS is already on file with the Department or if an MSDS needs to be submitted at the time a product is proposed for use.

The New York State Public Officer's Law and the Department's Records Access Regulations would continue to govern the handling of any other records submitted to the Department as part of the well permit application process, or in response to any Department request for additional additive product composition information.

8.2.2 Other Department Permits and Approvals

The Division of Environmental Permits (DEP) manages most other permitting programs in the Department and is therefore shown in Table 8.1 as 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, POTWs 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 DER's Part 364 program, and must obtain a Beneficial Use Determination for road-spreading from DMM. DFWMR would review new proposed surface withdrawals to assist DMN in its determination of whether a site-specific SEQRA determination is required. DAR would have a primary permitting role if emissions at centralized flowback water surface impoundments or well pads trigger regulatory thresholds.

8.2.2.1 Bulk Storage

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).

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 would not be stored on-site for 90 consecutive days; therefore, those chemicals are exempt from Part 596, "Registration of Hazardous Substance Bulk Storage Tanks" unless the storage period criteria are 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 5.7 are listed in Part 597.2(b).

8.2.2.2 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 ECL Section 15-0503, 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, the Department's Dam Safety Regulations and the associated Protection of Waters permitting program.

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.[531]

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:

- a height equal to or greater than fifteen feet;[532] or
- a maximum impoundment capacity equal to or greater than three million gallons.[533]

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

- a height equal to or less than six feet regardless of the structure's impoundment capacity; or
- an impoundment capacity not exceeding one million gallons regardless of the structure's height.

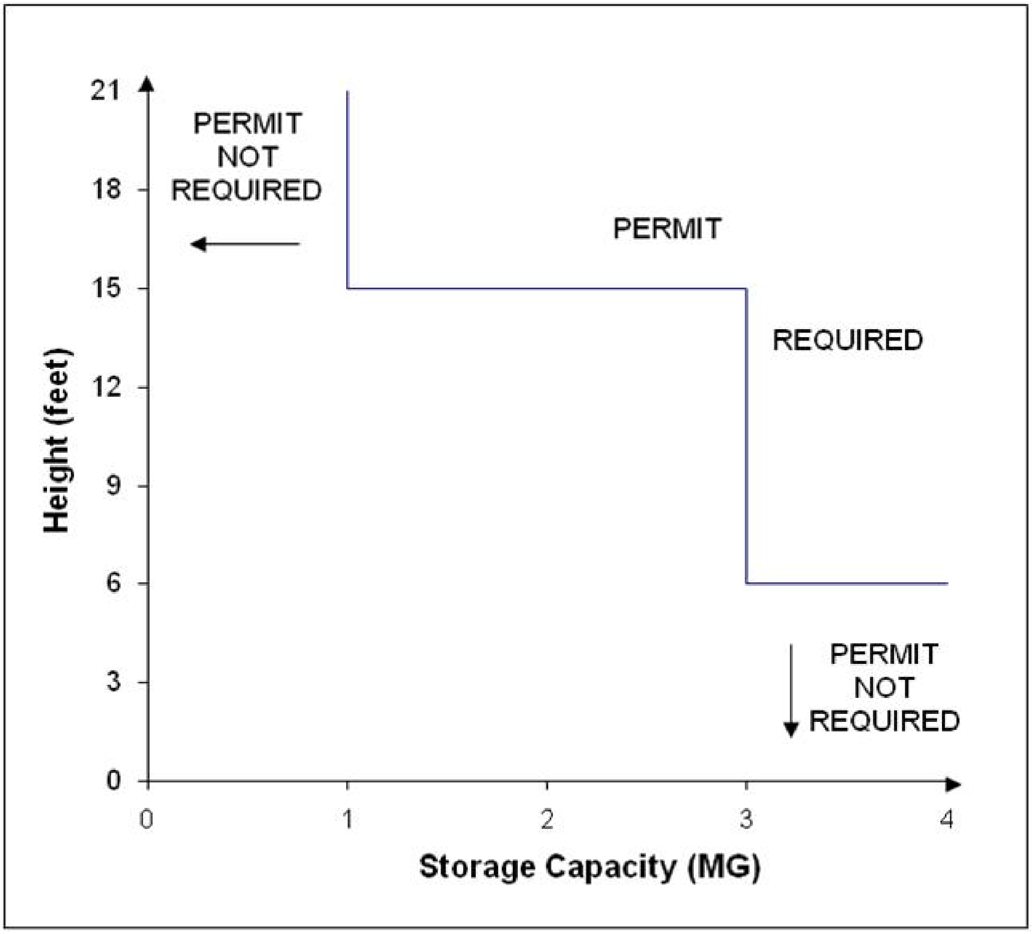
[531] NYSDEC Notice of Adoption of Amendments to Dam Safety Regulations.

[532] 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.

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

Figure 8.1 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 8.1- 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[534] and from the Regional Permit Administrator[535] for the county where the impoundment project is proposed. A complete application package[536] 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;

[534] Downloadable permit application forms are available at http://www.dec.ny.gov/permits/6338.html.

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

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

- 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; and

- 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 SEQRA, 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; and

- 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,"[537] which conveys sound engineering practices and outlines 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:

- 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[538]; hydrology[539]; water course and waterbody integrity;
- the adequacy of design and construction techniques for the structure;
- operation and maintenance characteristics;
- the safe commercial and recreational use of water resources;
- the water dependent nature of a use;
- the safeguarding of life and property; and
- 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

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537 "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.

538 Water Quality may include criteria such as temperature, dissolved oxygen, and suspended solids.

539 Hydrology may include such criteria as water velocity, depth, discharge volume, and flooding potential.

particular physical characteristics of the impoundment and its location, and may be irrespective of the size of the impoundment, as appropriate. The four potential Hazard Classifications, as defined by subdivision (b) of Section 673.5, are as follows:

- 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; and

- 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 Department 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 any 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.

8.2.3 Enforcement

Although DMN would retain a lead role in the review of Article 23 well permit applications and DOW would be responsible for implementing the HVHF GP and approving the discharge from POTWs who may accept waste from drilling operations, enforcement of violations of the ECL will require a multi-divisional approach. The SGEIS addresses a broad range of topics and requires mitigation for all aspects of a well drilling operation beginning with the source of fresh water for hydraulic fracturing and proceeding long after production wells are drilled. Some of the proposed mitigation measures identified in Chapter 7 would take the form of permit conditions attached, as appropriate, to the permit to drill issued pursuant to ECL Article 23. However, most of the proposed mitigation measures will be set forth as revisions or additions to the Department's regulations. Appendix 10 contains proposed supplementary permit conditions for high-volume hydraulic fracturing, most of which will become revisions or additions to the Department's regulations. Failure of a well operator to adhere to conditions of the permit would be considered a violation of ECL Article 23 and the failure of a well operator to comply with the HVHF GP would be considered a violation of ECL Article 17. Failure of an operator to follow the regulations of the Department would be considered a violation of the ECL Article 71.

While there are several different types of approvals needed from the Department in order to site wells for high-volume hydraulic fracturing in New York, there are two permits that would be specifically issued by the Department: the Article 23 permit to drill and the HVHF GP. For informational purposes, a more detailed description of how those permits would be enforced is provided below. This description is not intended to be exhaustive, since the type of enforcement response depends entirely on the nature of the violation. For more detailed descriptions of the Department's regulations and enforcement policies, the Department's website should be consulted.

8.2.3.1 Enforcement of Article 23

The Oil, Gas & Solution Mining Law vests the Department with the authority to regulate the development, production and utilization of the state's natural energy resources. There are three essential policy objectives embodied in ECL 23. Those objectives are to: 1) to prevent waste of the oil and gas resource as "waste" is defined in the statute; 2) to provide for the operation and development of oil and gas properties to provide for greater ultimate recovery of the resource, and; 3) to protect the correlative rights of all owners and the general public. To carry out these objectives, ECL 23 specifically provides the Department with the authority to, among other things:

> "Require the drilling, casing, operation, plugging and replugging of wells and reclamation of surrounding land in accordance with rules and regulations of the department in such manner as to prevent or remedy the following, including but not limited to: the escape of oil, gas, brine or water out of one stratum into another; the intrusion of water into oil or gas strata other than during enhanced recovery operations; the pollution of fresh water supplies by oil, gas salt water or other contaminants; and blowouts, cavings, seepages and fires." ECL 23-0305(8)(d).

Along with other powers enumerated in ECL 23, this broad grant of authority is implemented through the Department's oil and gas well regulations, found at 6 NYCRR Part 550, and through the imposition of conditions attached to a permit to drill issued by the Division of Mineral Resources. ECL Article 71 makes it unlawful for any person to fail to perform a duty imposed by ECL 23 or to violate any order or permit condition issued by the Department. Therefore, a failure of an operator to comply with a permit to drill exposes the well operator to an enforcement action. Enforcement actions may be pursued through administrative, civil or criminal means, depending on the nature of the violation. The Department may also call upon the Attorney General to obtain injunctive relief against any person violating or threatening to violate ECL 23.

Violations which are pursued administratively may result in an Order on Consent, which is a settlement agreement signed by the Department and the well operator. There are two Department policy documents which describe penalty calculations and the necessary components of an Order and Consent: DEE-1, Civil Penalty Policy, and: DEE-2, Order on Consent Enforcement Policy. Both policies can be found on the Department's website at: http://www.dec.ny.gov/regulations/2379.html. In cases where a settlement is not reached, a hearing may be held pursuant to the Department's Uniform Enforcement Hearing Procedures.

The Oil, Gas & Solution Mining Law also provides the Department with the administrative power to shut-in drilling or production operations whenever those operations fail to comply with ECL 23, the Department's regulations or any order issued by the Department. This power, found in ECL 23-0305(8)(g), is injunctive in nature and allows the Department to immediately address a violation without the need for a court order. This is an effective enforcement tool, particularly in the case of producing wells since the Department, through 6 NYCRR Part 558, may serve the shut-in order on a pipeline company or carrier, preventing them from transporting product from an operator found in violation of Article 23.

8.2.3.2 Enforcement of Article 17

The Department will take appropriate action to ensure all regulated point source and non-point source dischargers comply with applicable laws and regulations to protect public health and the intended best use of the waters of the state in accordance with "Technical and Operational guidance Series (TOGS) 1.4.2 – Compliance and Enforcement of State Pollutant Discharge Elimination System (SPDES) Permits." This guidance applies to all SPDES permits, including individual and general permits.

TOGS 1.4.2 supplements existing Department policy regarding civil enforcement actions for dischargers subject to individual and general permits and provides the minimum enforcement response and penalty (if applicable). When appropriate, more stringent enforcement responses may be utilized.

The focus of compliance and enforcement activities is based on resolving priority violations. Any point source or non-point source discharge to an identified current year CWA Section 303(d) List of Impaired Waters segment; water bodies with a TMDL strategy or other restoration measure; or a sole-source and/or primary aquifer is also a priority. Discharges from non-significant class facilities and unregulated non-point source discharges remain subject to compliance and enforcement activities as necessary for the protection of public health and the intended best use of the waters of the state.

Protection of the state's water resources is required regardless of the Department's compliance and enforcement priorities. Any discharge that causes or contributes to a contravention of the water quality standards contained in 6 NYCRR Part 700 et seq. (or guidance values adopted pursuant thereto), or impairs the quality of waters, or otherwise creates a nuisance or menace to health, is a violation of ECL Article 17 and is subject to enforcement.

Discharging without the appropriate permit is a violation of ECL Article 17 and 6 NYCRR Part 750. A facility discharging without a permit is subject to enforcement prior to issuance of a permit. Therefore, processing and review of a permit application may be suspended if an enforcement action is commenced.

SPDES Compliance Evaluation

SPDES permits are issued to wastewater and stormwater dischargers for the protection of the waters of the State. Operation and maintenance of SPDES-permitted facilities must comply with applicable regulations pursuant to 6 NYCRR Part 750 and additional facility specific and general permit conditions. When conditions of a permit, enforcement order or court decree are not met or not implemented according to a schedule, water quality may be negatively impacted. Permit compliance leads to protection of the public health and the intended best use of the waters of the state.

The Department's SPDES permit compliance program is directly supported by the following elements which allow the Department to evaluate the compliance status of any regulated facility and determine whether violations have or may occur:

Periodic Self-Reporting - The Department controls discharges of pollutants from some SPDES permitted facilities by establishing pollutant specific effluent limits and operating conditions in the permit and/or Order on Consent. Compliance with these limitations and conditions via self-reporting is critical to the protection of water quality.

Some SPDES permits and Orders on Consent require reporting of pollutants that are discharged on a Discharge Monitoring Report (DMR). The DMR is used by the Department to evaluate a facility's compliance with permit limitations. The information reported on DMRs is entered into a database system for compliance assessment, tracking and reporting purposes. Timely and accurate filing of DMRs is vital to ensuring compliance with the permit.

The Division of Water (DOW) also relies on other reports (e.g., monthly operating, annual, toxicity testing and status reports) and notifications (e.g., completion of permit or Order on Consent compliance schedules), to determine the compliance status of a facility. These documents may supplement or be submitted in lieu of a DMR, as specified in each permit or enforcement order.

Inspections - The Department conducts site inspections and effluent sampling to monitor facility performance, and to detect, identify and assess the magnitude of violations by a discharger. The primary focus for inspections of individually permitted facilities is on major and significant minor point source discharges and facilities that pose the highest risk to public health and safety. The number and type of inspections to be performed at permitted facilities are determined during DOW's annual work planning process. The primary focus for inspections of general permitted facilities is established annually through the same work planning process. Standardized inspection forms have been developed to assist Department inspectors in assessing the compliance status of dischargers in relation to the permit conditions, regulatory and record keeping requirements. Additional inspection forms may be developed to comprehensively evaluate compliance with permits issued for this activity.

Inspection information is entered into a database system for compliance evaluation, tracking and reporting purposes. Inspection findings can be rated "satisfactory," "marginal" or "unsatisfactory." An unsatisfactory rating is considered a priority and may be subject to informal and/or formal enforcement.

The Department may use inspection information provided by federal, state and local governmental entities to supplement compliance evaluations.

Citizen Complaints - Citizen complaints and observations of possible violations may assist the Department's compliance and enforcement efforts for SPDES permits. The Department will evaluate the authenticity of alleged violations and impacts to the environment and/or public health and safety to determine an appropriate response. This response may include enforcement. A "Notice of Intent to Sue" is a formal legal letter of intent to commence a federal "citizens suit" that is served by private parties alleging violations of federal environmental laws, specifically the federal Clean Water Act (CWA). The Department has established a systematic approach in reviewing and responding to such Notices.

SPDES Enforcement

The Department detects, investigates and resolves violations which are likely to impact the public health or the water quality of the state. Staff will respond to each water priority violation using the appropriate tools, including formal enforcement actions if necessary, to expedite a return to compliance. To promote statewide consistency in the handling of water priority violations in all SPDES programs, TOGS 1.4.2 contains a SPDES compliance and enforcement response guide allowing staff to determine when enforcement is necessary to bring the facility back to compliance. TOGS 1.4.2 describes the range of options available to the Department for enforcement, ranging from warning letters and compliance conferences through more formal proceedings involving hearings, summary abatement orders and referral to the Attorney General's Office. For a more detailed description of all the avenues available to the Department for SPDES enforcement, TOGS 1.4.2 can be viewed at on the Department's website at: http://www.dec.ny.gov/docs/water_pdf/togs142.pdf.

SPDES Enforcement Coordination with EPA

The Department's obligations with respect to compliance and enforcement of SPDES permits are specified in the 1987 Enforcement Agreement between Region II of the USEPA and the Department. This agreement outlines the elements essential to ensure compliance by the regulated community. Some of these important elements are: monitoring permit compliance; maintaining and sharing compliance information with EPA; identifying criteria for significant non-compliance; listing facilities that require action by the Department to require non-complying facilities to return to compliance; and timely and appropriate enforcement for priority violations. The Department meets with EPA on a quarterly basis to cooperatively address priority violations at major facilities and agree on enforcement responses to these violations and other significant issues such as treatment plant bypasses, manure spills and citizen complaints.

Goals for the Department's water compliance assurance activities are defined in the Division of Water annual work planning process. The work plan identifies goals for activities such as for the numbers of inspections of facilities, management of data and number of enforcement actions. The work plan also sets priorities to meet the compliance goals set by the Department and EPA.

Region II EPA also enters into an annual inspection work plan agreement with the Department's Division of Water. The EPA inspection work plan identifies roles and responsibilities for EPA, communication and coordination protocols with Department. Enforcement response to violations detected by EPA inspections may be conducted by EPA and/or the Department depending on the situations. The Division of Water work plan and the EPA inspection work plan may be modified to account for permits required by this activity.

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 identifies 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, some or all of which may be promulgated in revised regulations, 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 proposes that high-volume re-fracturing 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.

8.4 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 directly attributable to the hydraulic fracturing process 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.[540] 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;

6) Pennsylvania Environmental Quality Board. Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells, Pennsylvania Bulletin, Col. 41. No. 6 (February 5, 2011); and

7) Statement by Lisa Jackson, EPA Administrator on May 24, 2011 at a House Committee on Oversight and Government Reform that she is "not aware of any proven case where the fracturing process itself has affected water."

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

[540] http://www.iogcc.state.ok.us/hydraulic-fracturing.

SGEIS. Pertinent sections of Colorado's final amended rules are also summarized, and a brief discussion of Pennsylvania's recent revisions to its Chapter 78 Rules is presented.

8.4.1 Ground Water Protection Council

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.

Emphasis on proper well casing and cementing procedures is identified by GWPC and state regulators as the primary safeguard against groundwater 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 requirements regarding either hydraulic fracturing or ancillary activities in other states that address potential impacts associated with horizontal drilling and high-volume hydraulic fracturing that are not covered by the 1992 GEIS.

8.4.1.1 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.

GWPC 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.

8.4.1.2 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,"[541] 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.

8.4.2 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).

8.4.2.1 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.

[541] GWPC, May 2009, p. 30.

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 would 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.

8.4.2.2 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."[542] 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 production brine;

- On-site encapsulation and burial of drill cuttings if they do not contain constituents at levels that exceed Pennsylvania's environmental standards;

- Containerization of sewage and putrescible waste and transport off-site to a regulated sewage treatment plant or landfill;

542 Alpha, 2009, p. 2-15.

- 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.[543]

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:

- 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);

543 Alpha, 2009, p. 2-15.

- 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.[544] Best management practices such as the following were identified by Alpha for implementation on the well pad:

- Monitoring and recording inventories;

- Manual inspections;

- Berms or dikes;

[544] Alpha, 2009, p. 2-31

- 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 would 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 8.3 were reported regarding the surveyed jurisdictions.

Table 8.3 - 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 from water supplies	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.

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.

8.4.3 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.

8.4.3.1 Colorado - New MSDS Maintenance and Chemical Inventory Rule

The following information is from a training presentation posted on COGCC's website.[545] 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:

[545] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009.

- 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.

8.4.3.2 Colorado - Setbacks from Public Water Supplies

The following information was provided by Alpha and supplemented from a training presentation posted on COGCC's website.[546]

Colorado's new rules require buffer zones along surface water bodies 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

[546] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009.

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.

8.4.4 Summary of Pennsylvania Environmental Quality Board. Title 25-Environmental Protection, Chapter 78, Oil and Gas Wells

A number of Pennsylvania's recent Chapter 78 revisions relate to enhancements to well control and construction requirements as a result of extensive drilling and completion operations in the Marcellus Shale in that state.[547] Specific casing and cementing procedures designed to protect drinking water supplies are now codified as a result of these revisions.

8.4.5 Other States' Regulations - Conclusion

Experience in other states is similar to that of New York as a regulator of gas drilling operations. Well control and 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.

[547] http://www.pacode.com/secure/data/025/chapter78/chap78toc.html "Chapter 78. Oil and Gas Wells.

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Chapter 9

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TABLES

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Chapter 9 ALTERNATIVE ACTIONS

Chapter 21 of the 1992 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 1992 GEIS was found to be the best alternative. Regulatory revisions recommended by the 1992 GEIS have been incorporated into permit conditions, which have been continuously improved since 1992.

The following alternatives to issuance of permits for high-volume hydraulic fracturing to develop the Marcellus Shale and other low-permeability gas reservoirs have been reviewed for the purpose of this SGEIS:

- The denial of permits to develop the Marcellus Shale and other low-permeability gas reservoirs by horizontal drilling and high-volume hydraulic fracturing (No-action alternative);
- 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; and
- The required use of “green” or non-chemical fracturing technologies and additives.

9.1 No-Action Alternative

The no-action alternative to the proposed action would be denial of permits to drill where high-volume hydraulic fracturing is proposed and a prohibition on development of the Marcellus Shale and other low-permeability reservoirs using this method. If the no-action alternative were selected, none of the potential significant adverse impacts identified in this SGEIS would occur. Unlike any other activity regulated by the Department, the potential for significant adverse impacts is wide-ranging and widespread, including impacts to water resources, forests, ecosystems and wildlife, air resources, and greenhouse gas emissions across a substantial portion of the State. There are also potential significant community impacts, including increased truck traffic, wear and tear on roads and bridges, increased noise and light pollution and industrialization of rural landscapes.

The impacts to water resources that would be avoided by the no-action alternative merit special attention. Even with mitigation measures in place, the risk of spills and other unplanned events resulting in the discharge of toxic pollutants over a wide area would not be eliminated. Moreover, the level of risk such spills pose to public health is highly uncertain.

At the same time, if the no-action alternative is selected, none of the economic benefits identified in Chapters 2 and 6 would occur through the extraction of this energy resource. However, the no-action alternative would also eliminate the anticipated costs associated with properly regulating high-volume hydraulic fracturing. These costs include repairing and replacing local infrastructure, responding to increased demands on emergency services and health care providers and conducting oversight of permit applications and operations under the permits and the investigation and remediation of any spills or discharges which will inevitably occur during high-volume hydraulic fracturing development and transportation. These impacts and response costs have the potential to overwhelm local, county and State governments and their capacity to deal effectively with the multi-dimensional nature of the impacts of high-volume hydraulic fracturing. Indeed, the Department estimates that the cost of administering this program under the average development scenario would grow from $14 million in the first year to nearly $25 million in the fifth year. These costs do not consider the other substantial costs that would be incurred by other state agencies, which would nearly double the total State costs associated with regulating high-volume hydraulic fracturing, or the costs imposed on local agencies.

As more fully described in Chapter 2, the Marcellus Shale, 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 Tcf with a recoverable estimate of 50 Tcf.[549] While it is very early in the productive life of Marcellus Shale wells, more recent estimates by

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

Engelder (2009) using well production decline rates indicate a 50% probability that recoverable reserves could be as high as 489 Tcf.[550]

The 2009 New York State Energy Plan recognized the potential benefit to New York from the strategic development of in-state energy resources, including renewable resources and natural gas:

> 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 and environmental objectives. To the extent that renewable resources and natural gas are able to displace the use of higher emitting fossil fuels, relying more heavily on these in-state resources will also reduce public health and environmental risks posed by all sectors that produce and use energy. 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.[551]

The 2009 Energy Plan further included a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.[552] This recommendation, however, is premised on the assumption that the development of the Marcellus Shale can be done in an environmentally sound manner. If, on the other hand that development cannot be done safely, or if there remain substantial public health and environmental impacts and increasing uncertainty as to those potential impacts or, correspondingly, the effectiveness of proposed safeguards, permitting development of the resource would be inconsistent with the caution expressed in the recommendation. Indeed, the most recent draft State Energy Plan (2014) excludes any mention of support for development of high-volume hydraulic fracturing.

Furthermore, the 2009 Energy Plan and the draft 2014 Energy Plan recognize that in order to achieve its overall greenhouse gas (GHG) emission reduction goals, the State must continue to transition from fossil fuels to non-emitting clean energy sources. Increased availability of low-cost natural gas has the potential to reduce the cost-effectiveness of investment in various types

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

[551] NYS Energy Planning Board, August 2009.

[552] NYS Energy Planning Board, August 2009.

of renewable energy and energy efficiency, thereby suppressing investment in and use of these clean energy technologies. While natural gas may serve as a "bridge" or "transitional fuel" towards greater utilization of non-emitting clean energy sources, increased natural gas development could extend the use of fossil fuels, or delay the necessary deployment of clean energy.

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 concluded 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, provide income 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.[553] However, as noted above, this recommendation fails to consider the environmental and public health impacts of high-volume hydraulic fracturing and the costs associated with allowing and/or properly regulating high-volume hydraulic fracturing.

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 would potentially place a temporal and/or geographic limit on impacts from high-volume hydraulic fracturing operations to the extent such limits were less than the annual demand for well permits. The proposed mitigation considered in Chapter 7 would partially adopt this alternative by restricting resource development in the NYC and Syracuse watersheds (plus buffer), public water supplies, primary aquifers and certain state lands. In addition, restrictions and setbacks relating to development in other areas near public water supplies, principal aquifers and other resources as outlined within this SGEIS, would further limit the areas with site disturbances.

[553] NYS Commission on Asset Maximization, June 2009.

A formal phasing plan is not practical because of the inherent difficulties in predicting gas well development rates and patterns for a particular region or part of the State. In addition, the Department's prior experience with well drilling in the State and its review of the development of high-volume hydraulic fracturing in other states suggests that well development tends to occur in phases and increase over time without a formal government mandate.

9.2.1 Inherent Difficulties in Predicting Gas Well Development Rates and Patterns

The level of impact on a regional basis would 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.

9.2.2 Known Tendency for Development to Occur in Phases without Government Intervention

Upon completion of this Supplement, permit issuance and drilling would start slowly as services and equipment are mobilized to the area and the Department gains experience in implementing the enhanced application review procedures. The drilling rate would ramp up over a number of years until it reaches a peak, and would then ramp down over several years until full-field development is reached.[554]

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 Table 9.1. (The source data provides information on the number of permits issued and is not indicative of the number of wells drilled.)[555]

[554] ALL Consulting, 2010, p. 6

[555] NTC Consultants, 2011, p. 36

Table 9.1 - Marcellus Permits Issued in Pennsylvania, 2007 - 2010

Year	Marcellus Permits Issued (Pennsylvania)
2007	99
2008	529
2009	1,991
2010	3,446

It is unknown whether the peak development rate has been reached in Pennsylvania, or how long it will take to reach full-field development in either Pennsylvania or New York. In general, however, the stages of development of a natural gas play can be grouped into five general categories: Exploration/Early Development, Moderate Development, Large-Scale Development, Post-Development Production and Closure and Reclamation. These stages are not discrete, but overlap and may occur concurrently in different areas. For example, initial production may begin during early development and well pads may be closed and reclaimed in one area as production continues elsewhere. In addition, development levels wax and wane as prices vary and technological advances occur.[556]

9.2.3 Prohibitions and Limits that Function as a Partial Phased Permitting Approach

As set forth below, the proposed mitigation considered in Chapter 7 would partially adopt a phased approach because it would restrict resource development in certain areas. In addition, restrictions and setbacks relating to development in other areas near public water supplies, principal aquifers and other resources as outlined within this SGEIS, would further limit the areas where site disturbances would be allowed for a certain period of time.

9.2.3.1 Permanent Prohibitions

The Department would not approve well pads for high-volume hydraulic fracturing:

- Within the NYC and Syracuse watersheds, or within a 4,000-foot buffer around those watersheds;
- Within 500 feet of private drinking water wells or domestic use springs, unless waived by the owner;

[556] Dutton and Blankenship 2010, p. 7.

- Within 100-year floodplains; and
- On certain state-owned land.

These limits would function as a partial "phased" permitting approach because they would prohibit activities in areas deemed to be especially sensitive. As reflected in the response to comments, subsequent to the issuance of the 2011 dSGEIS, the Department considered additional mitigation measures, such as banning any high-volume hydraulic fracturing development in the Catskill Park and eliminating sunset periods for various restrictions, in the face of ever increasing information detailing the actual environmental and public health impacts that result from high-volume hydraulic fracturing development.

9.2.3.2 Prohibitions in Place for at Least 3 Years

The Department would not approve well pads for high-volume hydraulic fracturing within 2,000 feet of public water supply wells, river or stream intakes or reservoirs until at least 3 years after issuance of the first permit for high-volume hydraulic fracturing. Reconsideration of this prohibition at that time would be based on actual experience and impacts associated with permit issuance outside these buffer zones. This approach functions as a partial "phased" permitting approach because it prohibits and limits activities in areas deemed to be especially sensitive where a phased and cautious approach is merited.

9.2.3.3 Prohibitions in Place for At Least 2 Years

The Department would not approve well pads for high-volume hydraulic fracturing within 500 feet of primary aquifers until at least 2 years after issuance of the first permit for high-volume hydraulic fracturing. Furthermore, during this time, the Department also would require site-specific SEQRA determinations of significance for proposed well pads within 500 feet of principal aquifers. Reconsideration of these restrictions after two years would be based on actual experience and impacts associated with permit issuance outside these buffer zones. These limits would function as a partial "phased" permitting approach because they would prohibit and limit activities in areas deemed to be especially sensitive where a phased and cautious approach is merited.

9.2.4 Permit Issuance Matched to Department Resources

The Department believes that any specific annual limit on the number of well permits to be issued would have to be tied to specific environmental, public health or community impacts to avoid a claim that the Department acted without a reasonable basis. The Department recognizes that the risk of significant adverse impacts has the potential to increase if permits were issued in excess of the Department's capacity to adequately police such development and enforce permit conditions. Accordingly, if permitting were allowed to proceed, the Department would consider a limitation on the number of permits it issues to match the Department resources that are made available to review and approve permit applications and to adequately inspect well pads and enforce permit conditions and regulations.

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.[557]

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 claimed benefits of such alternatives would need to be evaluated in a holistic manner, considering the full lifecycle impact of the technology or chemical.[558]

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:

[557] URS, 2009, pp. 6-1 - 6-7.

[558] URS, 2009, pp. 6-1 - 6-7.

Liquid CO_2 alternative – The use of a liquid CO_2 and proppant mixture reduces the use of other additives [19]. CO_2 vaporizes, leaving only the proppant in the fractures. The use of this technique in the United States has been limited to demonstrations or pilots [20]. The appropriate level of environmental review for this alternative, if proposed in New York, would be determined at the time of application;

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]. Nitrogen-based foam fracturing is discussed starting on page 9-27 of the 1992 GEIS (Volume 1); and

Liquefied Petroleum Gas (LPG) alternative – 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 flowed directly into a gas pipeline and separated at the gas plant and recycled [55]. LPG's high volatility, low weight, and high recovery potential make it a good fracturing agent. Use of LPG as a hydraulic fracturing fluid also inhibits formation damage which can occur during hydraulic fracturing with conventional 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.[559] As a result of the elimination of hydraulic fracturing source water, truck traffic to and from the wellsite would be greatly reduced. In addition, since LPG is less reactive with the formation matrix, it is therefore less likely to mobilize constituents which could increase NORM levels in the flowback fluid. LPG is discussed and addressed in the 1992 GEIS in the context of the permitting of underground gas storage wells and facilities in the State. Currently, there are three operating underground LPG storage facilities and associated wells for the injection and withdrawal of LPG, with a total storage capacity of approximately 150 million gallons of LPG. It is quite possible

[559] Smith, 2008, p. 3.

that these storage facilities which are located in Cortland, Schuyler and Steuben Counties could supply the LPG needed to conduct hydraulic fracturing operations at wells targeting the Marcellus Shale and other low-permeability gas reservoirs should a well operator make such a proposal for the Department's approval.

Well applications that specify and propose the use of LPG as the primary carrier fluid will be reviewed and permitted pursuant to the 1992 GEIS and Findings Statement. Horizontal and directional wells, which are part of the main subject of this SGEIS, are already in use in the Marcellus Shale. While these drilling techniques require larger quantities of water and additives per well because of the relatively longer target interval, 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].[560]

9.3.1 Environmentally-Friendly Chemical Alternatives

The use of alternative chemical additives in hydraulic fracturing is another facet to the "environmentally- friendly" development in recent years.

There are several US-based chemical suppliers who advertise "green" hydraulic fracturing additives. Examples include: 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; CleanStim by Halliburton; and "Green" Chemicals for the North Sea from BASF. The EPA has published the twelve principles of "green" chemistry and a sustainable chemistry hierarchy [30], yet these do not provide a common measure of environmental benefits to assess "green" hydraulic fracturing additives.[561]

Although several US-based chemicals suppliers advertise "green" chemicals, there does not seem to be a US-based metric to evaluate the environmental benefits of these chemicals.[562] The most significant environmentally conscious hydraulic fracturing operations and regulations to date are

[560] URS, 2009, pp. 6-1 - 6-7.

[561] URS, 2009, pp. 6-1 - 6-7.

[562] URS, 2009, pp. 6-1 - 6-7.

likely in the North Sea. Several countries have established criteria that define environmentally beneficial chemicals and utilize models and databases to track chemicals' overall hazardousness against those criteria. Similar to the Department, 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.[563] In addition, the manufacturers of these "green" alternatives point out that they are not effective under some conditions. For example, where high clay content is found in the shale formation, a petroleum distillate may be needed to carry compounds designed to address the difficulties created by the clay. It is, therefore, not evident that the ability of operators to choose the most effective fluids to perform hydraulic fracturing can be reasonably circumscribed by government restrictions at this time.

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 to establish benchmarks for "green chemicals", this SGEIS considers thresholds, permit conditions and review criteria to reduce or mitigate potential environmental impacts for development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. It also considers requiring that applicants evaluate and, where feasible, use alternative additive products that may pose less risk to the environment, including water resources. It also considers public disclosure of the additives, including additive MSDSs, used at each well. These requirements could be altered and/or expanded as clearer evidence emerges that the use of "green chemicals" can provide reasonable alternatives as the appropriate technology, criteria, and processes are developed to evaluate and produce "green chemicals."

[563] URS, 2009, pp. 6-1 - 6-7.

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Chapter 10

Review of Selected Non-Routine Incidents in Pennsylvania

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Chapter 10 REVIEW OF SELECTED NON-ROUTINE INCIDENTS IN PENNSYLVANIA

More than 3,000 Marcellus wells have been drilled in Pennsylvania since 2005, most of which have been or will be developed by high-volume hydraulic fracturing. A number of regulatory violations, non-routine incidents and enforcement cases have been widely publicized. Some of them are briefly described below, with information about the measures currently required in New York or those that the Department proposes to require that are designed to prevent similar problems if high-volume hydraulic fracturing is permitted in the Empire State.

10.1 Gas Migration – Susquehanna and Bradford Counties

10.1.1 Description of Incidents

In 2009, the appearance of methane in water wells in an area in Dimock Township, Susquehanna County, was attributed to excessive pressures and improperly or insufficiently cemented casings at nearby Marcellus wells.[564] Numerous occurrences of methane migration into residential water wells during 2010 in Tuscarora, Terry, Monroe, Towanda and Wilmot Townships, Bradford County were attributed to the failure to properly case and cement wells.[565]

10.1.2 New York Mitigation Measures Designed to Prevent Gas Migration Similar to the Pennsylvania Incidents

The potential for water wells to be impacted by methane migration associated with gas well construction was a high-profile concern in Chautauqua County, New York, in the 1980s. Then-Commissioner Henry Williams addressed the situation in a decision issued after a public hearing held in Jamestown. That decision, which among other things directed staff to (1) require wells in primary and principal aquifers to be cemented to surface and (2) prohibit excessive annular pressure, is the foundation of New York's current well construction requirements. The 1992 GEIS adopted minimum casing and cement practices, which are augmented as necessary to address site-specific conditions and incorporated as conditions of every well permit the Department issues. Additionally, the Department does not issue a permit to drill any well until the proposed wellbore design for that specific well and location has been reviewed by

[564] PADEP, 2009, p. 3.
[565] PADEP, 2011, p. 9.

Department staff and deemed satisfactory. Permits are not issued for improperly designed wells, and for high-volume hydraulic fracturing, as-built wellbore construction would be verified as described in Chapter 7. Additionally, intermediate casing would be required, unless clearly justified otherwise, with the setting depths of both surface and intermediate casing determined by site-specific conditions.

The effectiveness of the Department's well construction approach with respect to gas migration is demonstrated by the rarity of gas migration incidents in New York. The most recent incident occurred 15 years prior to the date of this document, in 1996, and resulted not from well construction but from the operator reacting improperly to a problem encountered while drilling. More than 3,000 wells have been drilled under ECL Article 23 permits since 1996 without another occurrence.

As noted in the 1992 GEIS and in Section 4.7 of this document, methane is naturally present in water wells in many locations in New York, for many reasons unrelated to gas well drilling. This is a fact which must be evaluated and considered when a gas drilling impact is suspected as a source of methane in water wells.

10.2 Fracturing Fluid Releases – Susquehanna and Bradford Counties

10.2.1 Description of Incidents

In 2009, three fracturing fluid releases occurred at a single well pad in Dimock Township, Susquehanna County. The releases resulted from equipment failures when the pressure rating of some piping components on the well pad were exceeded while the operator was mixing and pumping fluid for hydraulic fracturing. This resulted from a combination of pressure fluctuations while pumping and a significant elevation difference between the fresh water tanks and the well pad. The fresh water tanks were located 240 feet above the well pad and the mixing area was 190 feet above and over 2,000 feet away from the well pad.[566]

On April 19, 2011, an uncontrolled flow of hydraulic fracturing fluid occurred during fracture stimulation of Chesapeake Energy's Atlas 2H well in LeRoy Township, Bradford County. The Department's Commissioner visited this site on June 16, 2011, and was briefed by officials from

[566] Cabot Oil & Gas Corporation, 2009.

the Pennsylvania Department of Environmental Protection, Chesapeake Energy, and the Bradford County Soil and Water Conservation District. At the briefing and tour of the well pad, it was learned that a failure occurred at a valve flange connection to the wellhead, causing fluid to be discharged from the wellhead at high pressure. Approximately 60,000 gallons of fluid were discharged to the well pad, of which 10,000 gallons flowed over the top of the containment berms. A portion of this fluid made its way into an unnamed tributary of Towanda Creek. The wellhead failure is under investigation to determine the precise cause of the breach. The wellhead was pressure-tested after installation and after each hydraulic fracturing stage prior to the breach. According to Chesapeake officials, it passed all tests. The discharge of fluid from the well pad was caused by the failure of stormwater controls on the well pad due to extraordinary precipitation and other factors.[567]

10.2.2 New York Mitigation Measures Designed to Prevent Fracturing Fluid Releases

The site layout in Dimock was unusual and, if proposed in New York, would be flagged during the Department's review of the application materials, which always include maps and a pre-permitting site inspection. Such a layout would not be approved by the Department without site-specific permit conditions designed to address the risks associated with hillside locations. Steep slopes above surface water bodies reduce the time available to respond to a release or spill, and in New York locations on steep slopes above potential drinking water supplies are not eligible for authorization under a general stormwater permit.

It is important to note that in both cases it was mixed fracturing fluid that was released, not undiluted additives. Supplementary permit conditions for high-volume hydraulic fracturing in New York will require pressure testing of fracturing equipment components with fresh water prior to introducing additives.

10.3 Uncontrolled Wellbore Release of Flowback Water and Brine – Clearfield County

10.3.1 Description of Incident

In 2010 an operator in Lawrence Township, Clearfield County, lost control of a wellbore during post-fracturing cleanout activities, releasing natural gas, flowback water and brine into the

[567] Although described in press accounts as a "blowout," such terminology is not technically correct because the source of pressure was the fracturing operations on the surface. A blowout is an uncontrolled intrusion of fluid under high pressure into the wellbore, from the rock formation.

environment. It was determined that blowout prevention equipment was inadequate and that certified well-control personnel were not on-site.[568]

10.3.2 New York Mitigation Measures Designed to Prevent Uncontrolled Wellbore Release of Flowback Water and Brine

Proposed supplementary permit conditions for high-volume hydraulic fracturing would require pressure testing of blowout prevention equipment, the use of at least two mechanical barriers that can be tested, the use of specialized equipment designed for entering the wellbore when pressure is anticipated and the on-site presence of a certified well control specialist.

10.4 High Total Dissolved Solids (TDS) Discharges – Monongahela River

10.4.1 Description of Incidents

During seasonal low-flow conditions in the Monongahela River in 2008, an increase in gas-drilling wastewater discharges may have provided the TDS "tipping point" for the Monongahela River. At the time, many rivers in that state were unable to assimilate new high-TDS waste streams because they were already impaired by pre-existing elevated TDS levels from various historic practices, and Pennsylvania's regulations did not include a surface water quality standard for TDS. In the three years since these events occurred, Pennsylvania has enacted new regulations that restrict discharge of high-TDS wastewater associated with Marcellus Shale development. The PADEP has also requested that Marcellus operators discontinue discharging flowback water to facilities that are "grandfathered" from the new requirements. Additionally, as discussed in Section 1.1.1, operators in Pennsylvania are now reusing flowback water for subsequent fracturing operations.

10.4.2 New York Mitigation Measures Designed to Prevent High In-Stream TDS

New York's water quality standards include an in-stream limit for TDS and SPDES permits include effluent limitations based on a stream's assimilative capacity. As described in Chapters 7 and 8, and in Appendix 22, the Department has a robust permitting and approval process in place to address any proposals to discharge flowback water or production brine to wastewater treatment plants. Additionally, the Department anticipates that operators will favor reusing flowback water for subsequent fracturing operations as they are now doing in Pennsylvania.

[568] PADEP, 2010.

NEW YORK
STATE OF OPPORTUNITY.

Department of Environmental Conservation

Chapter 11

Summary of Potential Impacts and Mitigation Measures

Final

Supplemental Generic Environmental Impact Statement

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Chapter 11 – Summary of Potential Impacts and Mitigation Measures

TABLES

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Chapter 11 SUMMARY OF POTENTIAL IMPACTS AND MITIGATION MEASURES

A complete description of the potential impacts associated with horizontal drilling and high-volume hydraulic fracturing is presented in Chapter 6. The mitigation measures proposed to minimize those impacts are discussed in Chapter 7, while the associated Supplementary permit conditions are provided in Appendix 10. Additionally, Chapter 8 includes descriptions of other applicable state and federal regulatory programs which have authority over activities associated with natural gas well development. Table 11.1 below provides a summary of the potential impacts and proposed mitigation measures.

Table 11.1 Summary of Potential Impacts and Proposed Mitigation Measures

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
Water resources	Depletion of water supply in streams.	6.1.1.1	6-2	*6.1.1.1*				Requires determination of and adherence to passby flow for each surface water proposed for withdrawals using the Natural Flow Regime method.	7.1.1.4	7-14	*7.1.1.4*			
	Reduced stream flow and degradation of a stream's best use.	6.1.1-2	6-2	*6.1.1-2*				Same as above.						
	Loss or impairment of aquatic habitat, aquatic ecosystems, or aquifer recharge ability in surface waters.	6.1.1.3-6	6-2-6-5	*6.1.1.3-6*				Same as above.						
								Requires site-specific SEQRA review from any lake or pond.	7.1.1.4	7-14	*7.1.1.4*			
	Long-term damage to groundwater resources	6.1.1.6	6-5	*6.1.1.5*				Requires pump testing and site-specific SEQRA for groundwater withdrawal near wetlands and water wells	7.1.1.5	7-24	*7.1.1.5*			
	Cumulative surface water withdrawal impacts.	6.1.1.7	6-6	*6.1.1.7*				Addressed by individual passby flow determinations as above.	7.1.1.6	7-25	*7.1.1.6*			
	Contamination of surface and/or subsurface waters from stormwater runoff.	6.1.2	6-14	*6.1.2*		*16.B.3.a,b*	*16-12..15*	Requires erosion prevention and sediment control through development of and adherence to a SWPPP through a SPDES permit.	7.1.2	7-26	*7.1.2*			
								Requires application for and coverage under the General Permit before commencement of operations.	7.1.2	7-26	*7.1.2*			
								Authorizes permit conditions on a case-by-case basis regarding erosion and sediment control in watersheds of drinking water reservoirs.					*17.B.1.j*	*17-6*
								Specifies a reclamation timetable of 45 days following cessation of drilling.					*17.B.2.c*	*17-7*
								Requires a Stream Disturbance Permit when project is w/in 50' of a protected stream. Authorizes permit conditions on a case-by-case bais regarding stream crossings, access roads, EPSC measures, and reclamation.					*17.B.1.d*	*17-4..5*
								Well pads for high-volume hydraulic fracturing prohibited within 2000' of public drinking water wells, river or stream intakes and reservoirs.	7.1.11	7-29	*7.1.12.1*		*17.B.1.c*	*17-4*
								Specifies setback distances from structures, surface waters, public/private water wells, and water supply springs.	7.1.11	7-29	*7.1.12.1*		*17.B.2.a*	*17-6..7*

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RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
Water resources (cont.)	Contamination of surface waters, groundwater, or drinking water aquifers from chemical, fuel, or lubricant spills (including drilling and fracturing fluids).	6.1.3	6-15	*6.1.3*		*16.B.4.a,c*	*16-16..19*	Requires reporting in EAF addendum of location of fuel tanks relative to surface waters, wetlands, drinking water wells, and aquifer boundaries.	7.1.3.1	7-33	*7.1.3.1*			
								No well pads within 500' of a private water well, unless waived by the landowner.	7.1.3.1	7-33	*7.1.3.1*			
								Specifies continuous monitoring of refueling operations.	7.1.3.1	7-33	*7.1.3.1*			
								Requires spill response and cleanup to be addressed in the SWPPP by inclusion of Best Management Practices to control, remediate, and clean up spills.	7.1.3.1	7-33	*7.1.3.1*			
								Individual crew member responsibilites must be posted for well-control. Blowout Preventers (BOPs) must be adequately sized and tested.	7.1.3.2	7-34	*7.1.3.2*			
								Affords DEC option to implement location-specific HVHF fluid management restrictions and permit conditions.	7.1.3.3	7-38	*7.1.3.3*			
								Hydraulic fracturing fluid additives should be required by permit condition to be placed in lined containment areas.	7.1.3.3	7-38	*7.1.3.3*			
								Identification of a spill response team and employee training on proper spill prevention and response techniques.	7.1.3.3	7-38	*7.1.3.3*			
								Requires a closed-tank system for flowback water handled at the wellpad.	7.1.3.4	7-39	*7.1.3.4*			
								Requires reporting EAF addendum on quantity, worthiness, volume, and location of tanks to accept flowback water.	7.1.3.4	7-39	*7.1.3.4*			
								Promote reuse of flowback water	7.1.3.4	7-39	*7.1.3.4*			
								Requires operators to consider less toxic alternative hydraulic fracturing fluid additives.	8.2.1.1	8-29	*8.2.1.2*			
								Limits duration of fluid impoundment after permanent/temporary suspension of drilling/hydraulic fracturing.	7.1.3.4	7-39	*7.1.3.4*			
Water resources (cont.)	*Contamination of surface waters, groundwater, or drinking water aquifers from chemical, fuel, or lubricant spills (including drilling and fracturing fluids). (cont.)*							Specifies continuous supervision of fluid transfer activities.	7.1.3.4	7-39	*7.1.3.4*			

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
								Specifies spill prevention and response BMPs to be addressed in SWPPP. At least two vacuum trucks must be on standby at the wellsite during the flowback phase.	7.1.3.4	7-39	*7.1.3.4*			
								Requires dikes around oil storage tanks.					*17.B.2.f*	*17-7*
								References requirement for BOPs on wells in NY state.					*17.C.1.l*	*17-12*
								Subjects operators to enforcement actions and penalties upon release of flowback fluids onto the ground.					*17.C.1.m*	*17-12*
								Affords right to the department to require fluid-level monitors on tanks where repeated overflows have occurred.					*17.D.2.c*	*17-16*
								Specifies frequency and character of sampling, testing, and reporting of nearby private water wells before, during, and after drilling and HVHF activity.	7.1.4.1	7-44	*7.1.4.1*			
								Affords DEC the right to curtail or modify operations when a well complaint and a non-routine wellpad incident coincide.	7.1.4.1	7-44	*7.1.4.1*			
Water resources (cont.)	Contamination of groundwater/aquifers from natural gas, drilling fluids, or HVHF fluids in the wellbore.	6.1.4	6-41	*6.1.4*				No well pads for high-volume hydraulic fracturing within the boundaries of a primary aquifer.	7.1.3.5	7-40	*7.1.3.5*		*17.C.1.q*	*17-12..13*
								No well pads for high-volume hydraulic fracturing permitted within 500' of a primary aquifer	7.1.3.5	7-40	*7.1.3.5*			
								No well pads for high-volume hydraulic fracturing within 500' of a principal aquifer without site-specific SEQRA review and an individual SPDES permit	7.1.3.5	7-40	*7.1.3.5*			
								Requires operator to test private water wells	7.1.4.1	7-44	*7.1.4.1*			
								Specifies permit conditions for more stringent casing construction and cementing, reporting of well information, and testing of cement job for HVHF wells.	7.1.4.2	7-49	*7.1.4.2*			
								Requires departmental notification prior to surface casing cementing.	7.1.4.2	7-49	*7.1.4.2*			
								Specifies constant venting of annulus to prevent pressure buildup, unless the annular gas is to be produced, in which case the equipment and production pressure must receive departmental approval.	7.1.4.3	7-55	*7.1.4.3*			

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
								Requires diligence of operator in researching, locating, characterizing, and reporting public and private water wells within 2640 feet (1/2 mile) of proposed well.	7.1.11.1	7-71	*7.1.12.1*			
								Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and plug any abandoned well which is open to the target formation or is otherwise an immediate threat to the environment.	7.1.6	7-56	*7.1.6*			
								Specifies methods and materials for the installation and cementing of the various casings, including the dimensions of cementing to isolate the producing and other gas-bearing formations from overlying, potentially, water-supplying formations.					*17.C.1.g-j*	*17-8..11*
								State Inspector must be present during surface and production string cement jobs. State may order remedial cement work.					*17.C.1.q*	*17-12*
Water resources (cont.)	*Contamination of groundwater/aquifers from natural gas, drilling fluids, or HVHF fluids in the wellbore. (cont.)*							Requires continuous venting of annulus.					*17.C.1.q*	*17-13*
								Requires properly plugging and abandoning well by isolating hydrocarbon bearing formations with cement plugs, heavy mud, and casing withdrawal.					*17.E.1.c-d*	*17-17..18*
								Further specifies plugging materials and methods to ensure vertical isolation across the well depth.					*17.E.2.c-d,f,h-m*	*17-19..22*
								Limits duration of temporary abandonment of wells.					*17.E.1.e-f*	*17-18*
								Extends limits on duration of temporary abandonment to all wells (see 17.E.1.e-f).					*17.E.2.o*	*17-23*
								Affords the department the right to take temporary possession of and plug any well in case of operator neglect or unpermitted abandonment, and requires financial security prior to application to fund said operation.					*17.E.1.a,j*	*17-17..18*
	Contamination of aquifers/ groundwater from hydraulic fracturing	6.1.5	6-43	*6.1.5*				Requires site-specific SEQRA review of HVHF permit applications to produce from a formation with < 1000' of vertical separation from potential or known subsurface water supplies. (see 6.1.5.2)	7.1.5	7-55	*7.1.5*			
Water resources (cont.)	Contamination of surface or subsurface water with HVHF or drilling fluids from container leakage, structural failure, or improper transportation.	6.1.6	6-53	*6.1.6*		*16.B.3.b,c*	*16-14..15*	Closed-tank systems must be used for flow-back of wells.	7.1.3.4	7-39	*7.3.1.2*			

Table 11.1 Summary of Potential Impacts and Proposed Mitigation Measures

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
								Requires impermeable liner in drilling reserve pits.					*17.C.1.o*	*17-12*
								Limits duration on impoundment of waste fluids to 45 days after drilling operations.					*17.C.1.p*	*17-12*
								Specifies methods and materials for pit liners.					*17.C.2.k-l*	*17-15*
Water resources (cont.)	Contamination of soil or water from improper disposal, transportation, or release of waste solids or fluids (including HVHF flowback).	6.1.6-9	6-53-6-66	*6.1.6-9*				Flowback water may not be spread on roads. Requires coverage under a Part 364 permit and submission of BUD application for road-spreading of produced brine (includes independent analysis of brine composition). BUDs for Marcellus brine will not be issued until additional data on NORM content is available and evaluated.	7.1.7.2	7-60	*7.1.7.2*			
								Cuttings must be disposed of in MSW landfills if well drilled on oil-based or polymer-based mud. Cuttings may be disposed of on location only if well drilled on air or water.	7.1.9	7-67	*7.1.9*			
								Prohibits annular disposal of drill cuttings.	7.1.9	7-67	*7.1.9*			
								Requires landowner permission to bury trash or pit liners onsite.					*17.B.2.e*	*17-7*
								Specifies safe disposal of waste oil and flammables.					*17.C.1.d*	*17-8*
								Requires a department-approved brine disposal plan.					*17.D.2.b*	*17-16*
								Requires proper handling of well construction waste fluids and holding tanks for produced fluids.					*17.C.1.q*	*17-12..13*
								Sets timetable for waste fluid disposal to 45 days after cessation of drilling.					*17.D.2.a*	*17-16*
Water resources (cont.)	*Contamination of soil or water from improper disposal/release of waste solids or fluids (including HVHF flowback) into the environment. (cont.)*							Specifies and requires record-keeping of generation, transfer/hauling, and receipt of flowback wastewater.	7.1.7.1	7-59	*7.1.6.1*			
								Prohibits spreading of HVHF flowback water on roads.	7.1.7.2	7-60	*7.1.6.2*			
								Requires submission of a fluid disposal plan for flowback water which specifies quality, maintenance, and monitoring of piping and conveyances.	7.1.7.1	7-59	*7.1.6.3*			

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
								Requires application and pre-approval of POTWs proposing to dispose of flowback and production waters. Specifies application contents (e.g. headworks analysis, waste fluid characterization, regulatory limits) and demonstration that final discharges will fall within regulatory limits.	7.1.8.1	7-63	*7.1.8.1*			
								Requires SPDES coverage of any private wastewater treatment facility proposed to accept waste fluid.	7.1.8.1	7-63	*7.1.8.1*			
								Restates governance of EPA UIC permit over proposed injection well disposal. Notes site-specific SEQRA review for each injection well.	7.1.8.2	7-65	*7.1.8.2*			
Water resources (cont.)	Degradation/contamination of the NYC/unfiltered water supplies.							No well pads for high-volume hydraulic fracturing in the New York City or Syracuse watersheds or within a 4000' buffer of the watersheds.	7.1.10	7-68	*7.1.10*			
Floodplains	Contamination of surface waters from the release into the environment of chemical pollutants in a flood event.	6.2	6-67	*6.2*				No well pads or access roads for high-volume hydraulic fracturing permitted within 100-year floodplains.	7.2	7-77	*7.2*			
Freshwater Wetlands	Contamination of freshwater wetlands from accidental release of drilling or HF fluids, chemicals, or fuel.	6.3	6-67	*6.3*		*16.B.2.d*	*16-7..8*	For Department-regulated wetlands, makes permit approval dependent on site-specific SEQRA review and coverage under any necessary wetlands permits.	7.3	7-77	*7.3*			
								Specifies setbacks between fuel tanks and wetlands at a mandatory 500 feet.	7.3	7-77	*7.3*			
								Requires SPOTS 10 secondary containment for any fuel tank.	7.3	7-77	*7.3*			
								Requires a Wetlands Permit when project is w/in 100' of a freshwater wetland > 12.4 ac. in size or of unique local significance. Authorizes permit conditions on a case-by-case basis regarding location and timing of activities/facilities and replacement of lost wetland acreage.					*17.B.1.f*	*17-5*
Ecosystems and Wildlife	Degradation of local ecosystem from fragmentation of habitat	6.4.1	6-68	*6.4.1*				Requires operator to develop and employ Best Management Practices for surface disturbance to reduce habitat impacts.	7.4.1	7-78	*7.4.1*			
								Restricts operations during mating and migration seasons in certain habitats	7.4.1	7-78	*7.4.1*			
								Requires pre-drilling and post-completion animal and plant surveys when well pads are located in 150-acre or larger forest patches within Forest Focus Areas or 30-acre or larger grassland patches within Grassland Focus Areas.	7.4.1	7-78	*7.4.1*			

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
	Degradation of local ecosystem functions and native biological communities from the introduction of invasive species.	6.4.1	6-68	*6.4.1*				Requires operator diligence in exploiting accepted BMPs for removal and preventing introduction of invasive species.	7.4.2.1	7-88	*7.4.2.1*			
								Requires baseline surveying and reporting of project site for existence of invasive species.	7.4.2.1	7-88	*7.4.2.1*			
								Affords DEC the right to apply permit conditions for invasive species management when outside of the DRB and SRB.	7.4.2.2	7-91	*7.4.2.2*			
								Relies upon DRBC and SRBC protocols for aquatic invasive species management in their respective jurisdictions.	7.4.2.2	7-91	*7.4.2.2*			
Ecosystems and Wildlife (cont.)	Harm to local wildlife populations from the loss of habitat	6.4.3	6-89	*6.4.3*		*16.B.2.b*	*16-6..7*	Requires partial and final well pad reclamation.	7.4.1	7-78	*7.4.1*			
	Impacts to State-Owned Lands	6.4.4	6-91	*6.4.4*				No surface drilling allowed on specified State-owned lands.	7.4.4	7-99	*7.4.4*			
Air Quality	Degradation of Air Quality	6.5	6-94	*6.5*		*16.B.2.f*	*16-9..10*	Specifies minimum exhaust-stack heights, restrictions on public access, and sulfur content of fuel-oil.	7.5.3.1	7-107	*7.5.3.1*			
								Prohibits use of the BTEX class of compounds as additives in HVHF fluid surface impoundments.	7.5.3.2	7-108	*7.5.3.2*			
								Requires reporting of fracturing additives and public access restrictions.	7.5.3.2	7-108	*7.5.3.2*			
								Requires catalytic technology for production equipment.	7.5.1.1	7-101	*7.5.3.3*			
Greenhouse Gas Emissions	Emission of gases with Global Warming Potential due to natural gas well drilling and production.	6.6	6-189	*6.6*				Requires development of a GHG emissions impacts mitigation plan, requires development of a leak detection and repair program, and encourages participation in the USEPA's Natural Gas STAR program. Requires reduced emission completions where a pipeline is available.	7.6.8	7-115	*7.6.8*			
Naturally Occuring Radioactive Material (NORM)	Exposure of workers, the public, and the environment to harmful levels of radiation.	6.8	6-210	*6.8*				Outlines necessary monitoring work.	7.7.2	7-116	*7.8.2*			
								Requires NORM testing of discharged waste fluids and material in production tanks.	7.7.2	7-116	*7.8.2*			
Visual Impacts	Temporary new landscape features at well pads, new offsite facilities, congested appearance of campsites and staging areas, increase in specialized traffic.	6.9	6-266	*6.9*		*16.B.2.e*	*16-8*	Permit conditions would require operation consistent with a visual impacts mitigation plan. Site-specifc assessment could result in additional design and siting requirements.	7.9	7-120	*7.9*			

Table 11.1 Summary of Potential Impacts and Proposed Mitigation Measures

RESOURCE	IMPACT	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	SGEIS section	SGEIS pp.	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
Noise	Temporary impacts but could occur on 24-hour basis. Potential 37-42 dB increase over quietest background at 2,000 feet during drilling and hydraulic fracturing. Increased traffic noise near well pad. Noise along approach and departure corridors from increased airplan service.	6.10	6-292	*6.10*		*16.B*	*16-2*	Operator must submit and adhere to a noise impacts mitigation plan. Site-specific assessment could result in specific mitigating permit conditions.	7.10	7-127	*7.10*		*17.B.1.b*	*17-4*
Transportation	Increased traffic on roadways; damage to local roads, bridges and other infrastructure; damage to state roads, bridges and other infrastructure; increased number of breakdowns and other accidents; risk of potentially hazardous spills; traffic impacts near rail centers.	6.11	6-303	*6.11*				Potential for road use agreements between operators and municipalities. Requirement to file a transportation plan that includes prposed routes and a road condition assessment. Site-specific assessment could result in additional traffic safety requirements, first responder emergency response training or avoidance of sensitive locations for trucks carrying hazardous materials.	7.11	7-134	*7.11*			
Socioeconomic & Community Character	Positive impacts on employment and income; increased economic activity; potential localized housing shortages; positive and negative impacts on state and government spending; increased tax revenues and production royalties; increased demand for local services; potential changes in the economic, demographic and social characteristics of affected communities that could be viewed as negative by some and positive by others.	6.8 & 6.12	6-210 & 6-319	*6.8 & 6.12*		*16.B.2.h*	*16-10..11*	This section will be updated after July 31, 2011.	7.8 & 7.12	7-118 & 7-143	*7.8 & 7.12*			

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NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Glossary

Final

Supplemental Generic Environmental Impact Statement

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Terms and Definitions

Term	Definition
Access Road:	A road constructed to the wellsite that provides access during the drilling and operation of the well.
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.
AGC/SGC:	Annual Guideline Concentrations and Short-term Guideline Concentration defined in DAR-1 (Air Guide 1) procedures.
ALJ:	Administrative Law Judge.
Anaerobic:	Living or active in the absence of free oxygen.
Annular Space or Annulus:	Space between casing and the wellbore, or between the tubing and casing or wellbore, or between two strings of casing.
ANSS:	USGS’s Advanced National Seismic System.
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.
Aquifer:	A zone of permeable, water saturated rock material below the surface of the earth capable of producing significant quantities of water.
ARD (Acid Rock Drainage):	Refers to the outflow of acidic water from (usually abandoned) metal mines or coal mines. Acid rock drainage occurs naturally within some environments as part of the rock weathering process, usually within rocks containing an abundance of sulfide minerals.
AST:	Above-ground storage tank.

Term	Definition
Bactericides:	Also known as a "Biocide." An additive that kills bacteria.
Barrel:	A volumetric unit of measurement equivalent to 42 U.S. gallons.
bbl:	Barrel.
bbl/yr:	Barrels per year.
Bcf:	Billion cubic feet. A unit of measurement for large volumes of gas.
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 mound or wall of earth or sand.
Biocides:	See definition for "Bactericides".
Blending Unit or Blender:	The equipment used to prepare the slurries and gels commonly used in stimulation treatments.
Blooie Line:	Pipe that diverts fluids from the wellbore to a reserve pit.
Blowout:	An uncontrolled flow of gas, oil or water from a well, during drilling when high formation pressure is encountered.
BMP:	Best Management Practices.
BOD:	Biochemical (or biological) oxygen demand.
BOP:	Blowout Preventer. A device attached immediately above the casing which can be closed and shut off the hole should a blowout occur.
Borehole:	See wellbore.
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.
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.

Term	Definition
Brine:	A solution containing appreciable amounts of NaCl and/or other salts. Synonymous with salt water.
BTEX:	Benzene, Toluene, Ethylbenzene, and Xylene. These are all aromatic hydrocarbons.
BUD:	Beneficial Use Determination issued by NYSDEC's Division of Materials Management.
Buffer Zone:	An area designed to protect and separate an activity from things around it.
C&D:	Construction and demolition.
CAA:	Clean Air Act.
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.
Carbonate:	A salt of carbonic acid, CO_3^{-2}.
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.
Casing:	Steel pipe placed in a well.
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.

Term	Definition
Cation:	A positively charged ion.
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 Sheath:	A protective covering around the casing, segregates the producing formation and prevents undesirable migration of fluid.
CFR:	Code of Federal Regulations.
cfs:	Cubic feet per second.
CH_4:	Methane.
Chemical Additive:	A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.
Chemical Constituent:	A discrete chemical with its own specific name or identity, such as a CAS Number, which is contained within an additive product.
Choke:	A device with an orifice installed in a line to restrict the flow of fluids.
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.

Term	Definition
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.
Closed Loop Drilling System:	A pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks.
CO:	Carbon monoxide.
CO_2:	Carbon Dioxide.
CO_2e:	Carbon Dioxide equivalents.
COGCC:	Colorado Oil and Gas Conservation Commission.
Completion:	Preparation of a well for production after it has been drilled to the objective formation and in the case of a dry hole, preparation of a well for plugging and abandonment.
Compressive Strength:	Measure of the ability of a substance to withstand compression.
Compressor Stations:	Facilities which increase the pressure on natural gas to move it in pipelines or into storage.
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 that were originally in the reservoir gas and are recovered by surface separation.
Conductor Hole:	The hole for conductor pipe or casing.

Term	Definition
Conductor Pipe or Casing:	Large diameter casing that is usually the first string of casing in a well. Set or driven into the unconsolidated material where the well will be drilled to keep loose material from caving in. Usually relatively short in length.
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.
CRDPF:	Continuously Regenerating Diesel Particulate Filter.
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.
CT:	coiled tubing.
Cubic Foot:	Unit of measurement of the volume of gas contained in one cubic foot of space at a standard pressure (14.73 psi) and standard temperature (60° F).
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.
CWF:	Cold-Water Fishery (waters).
CWS:	Community water systems.
CZM:	Coastal Zone Management.
DAR:	Division of Air Resources in 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.

Term	Definition
Dehydrator:	A device used to remove water and water vapors from gas.
Department:	New York State Department of Environmental Conservation.
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.
De-silter:	A centrifugal device used to remove very fine particles, or silt, from drilling fluid.
Devonian Period:	Period of geologic time from 415 to 360 million years ago.
Diesel-Based Hydraulic Fracturing:	Hydraulic fracturing using diesel as the primary carrier.
Dip:	Angle of inclination from the horizontal.
Dipole Sonic Log:	A type of acoustic log that displays travel time of P-waves versus depth.
Disconformity:	A surface of erosion between parallel rock strata or a contact between two discordant structures (e.g., a dike emplaced within a layered sedimentary rock unit).
Disposal Well:	A well into which waste fluids can be injected deep underground for safe disposal.
DMM:	Division of Materials Management in the NYS Department of Environmental Conservation.
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.

Term	Definition
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.
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.
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.
Effluent:	Something that flows out, in particular a waste material such as an industrial discharge.
EIS:	Environmental Impact Statement.
EM&CP:	Environmental Management and Construction Plan.

Term	Definition
EM&CS&P:	Environmental Management and Construction Standards and Practices.
Entrainment:	The condition of being drawn into something and transported with it, for example, gas bubbles in cement.
EO 41:	Executive Order 41.
EPA:	(U.S.) Environmental Protection Agency.
EPCRA:	Emergency Planning and Community Right to Know Act of 1986.
ERP:	Emergency Response Plan.
EUR:	Estimated ultimate recovery.
EV:	Exceptional Value (waters).
Evaporite:	Sedimentary rock or mineral deposits formed from the extensive or total evaporation of seawater.
FAA:	(U.S.) Federal Aviation Administration.
FAD:	Filtration Avoidance Determination.
Fault:	A fracture or fracture zone along which there has been displacement of the sides relative to each other.
Field:	The general area underlain by one or more pools.
Flare:	The burning of unwanted gas through a pipe.
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 Fluids:	Liquids produced following drilling and initial completion and clean-up of the well.
Flowmeter:	An instrument that measures fluid flow rates.

Term	Definition
Flue Gas:	An exhaust gas coming out of a pipe or stack.
FMCSA:	Federal Motor Carrier Safety Administration.
Foaming Agents:	An additive used to make foam in a drilling fluid.
Fold:	A bend in rock strata.
Footwall:	The mass of rock beneath a fault plane.
Formation:	A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.
Fossil:	A record of ancient life.
Fracing (pronounced “fracking”):	See 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 chance of overflow.
Friction Reducers/Friction Reducing Agent:	Chemical additives which alter the hydraulic fracturing fluid allowing it to be pumped into the target formation at a higher rate & reduced pressure.
FTIR:	Fourier-transform Infrared.
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 Gathering:	The collection and movement of raw gas from the wellhead to an acceptance point of a transportation pipeline.
Gas Meter:	An instrument for measuring and indicating, or recording, the volume of natural gas that has passed through it.
Gas-Water Separator:	A device used to separate undesirable water from gas produced from a well.
GEIS:	Generic Environmental Impact Statement.

Term	Definition
Gelling Agents:	Polymers used to thicken fluid so that it can carry a significant amount of proppants into the formation.
Geomembrane:	Man-made polymeric membrane (flexible membrane) that is manufactured to be essentially impermeable and is used to build containment pits.
Geothermal Well:	A well drilled to explore for or produce heat from the subsurface.
GHG:	Greenhouse gas.
gpd:	Gallons per day.
gpm:	Gallons per minute.
GRI:	Gas Research Institute.
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.
Groundwater Hydrology:	The science of the occurrence, distribution, and movement of water below the surface of the earth.
Grout:	A concrete mixture placed into a well annulus from the surface; also, the process of emplacing such mixture.
GWP:	Global warming potential.
GWPC:	Ground Water Protection Council.
H_2SO_4:	Sulfuric acid.
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.

Term	Definition
High-Volume Hydraulic Fracturing:	The stimulation of a well using 300,000 gallons or more of water as the base fluid in fracturing fluid.
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 perfectly parallel with formational layering.
HQ:	High Quality (waters).
Hydraulic Conductivity:	A property of a soil or rock, that describes the ease with which water can move through pore spaces or fractures. It is dependent upon the intrinsic permeability of the material and on the degree of saturation.
Hydraulic Fracturing:	The act of pumping hydraulic fracturing fluid into a formation to increase its permeability.
Hydraulic Fracturing Fluid:	Fluid used to perform hydraulic fracturing; includes the primary carrier fluid and all applicable additives.
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.
Hydrocyclone:	A device to classify, separate or sort particles in a liquid suspension based on the densities of the particles. A hydrocyclone may be used to separate solids from liquids or to separate liquids from different density.

Term	Definition
Hydrogen Sulfide or H_2S:	A malodorous, toxic gas with the characteristic odor of rotten eggs.
ICE:	Internal Combustion Engines.
ICF:	ICF International, a consulting firm.
Igneous Rock:	Rock formed by solidification from a molten or partially molten state (magma).
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.
IOGA-NY:	Independent Oil and Gas Association of New York.
IOGCC:	Interstate Oil and Gas Compact Commission.
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).
ITR:	Injection Timing Retard.

Term	Definition
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.
km:	Kilometer.
KML:	Keyhole Markup Language.
LCSN:	Lamont-Doherty Cooperative Seismographic Network.
LDAR:	Leak detection and repair.
LDCs:	Local Distribution Companies.
Limestone:	A sedimentary rock consisting chiefly of calcium carbonate ($CaCO_3$).
Lithologic:	Referring to the physical characteristics 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 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:	Formation that is so permeable or soluble that it diverts the flow of fluids from the well.
Low-Permeability Gas Reservoirs:	Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.
LPG:	Liquefied Petroleum Gas.

Term	Definition
LWRP:	Local Waterfront Revitalization Program.
Manifold:	An arrangement of piping or valves designed to control, distribute and often monitor fluid flow.
Marcellus Well:	A well for which the operator designates the Marcellus Shale as the objective formation.
Mcf:	Thousand cubic feet.
MCL, MCLG:	Maximum Contaminant Level, Maximum Contaminant Level Goal.
md:	Millidarcy.
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.
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.
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.
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:	Million cubic feet.
MMcf/d:	Million cubic feet per day.

Term	**Definition**
MOVES:	Motor Vehicle Emission Simulator.
mR/hr:	Milliroentgens per hour.
MSC:	Marcellus Shale Coalition.
MSDS:	Material Safety Data Sheet. A written or printed document which is prepared in accordance with 29 CFR 1910.1200(g).
MSGP:	Multi-Sector General Permit.
MSW:	Municipal solid waste.
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.
NCWS:	Non-community water systems.
NESHAPs:	National Emission Standards for Hazardous Air Pollutants.
NFRM:	Natural Flow Regime Method.
NGPA:	Natural Gas Policy Act of 1978.
NH_3:	Ammonia.
NMHC:	Non-methane hydrocarbons.
NNSR:	Nonattainment New Source Review.
NOI:	Notice of Intent.
Noise Log:	A record of the sound vibrations in the wellbore caused by flowing liquid or gas. Used to determine fluid entry points or flow behind casing.

Term	Definition
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.
Nonwetting Phase:	The pore space fluid which is not attached to the reservoir rock and thus has the greatest mobility.
N_2O:	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.
Non-Indigenous:	Not having originated in and being produced, growing, living, or occurring naturally in a particular region or environment.
Normalized Pressure Integral Curve Analysis:	Another type of Decline or Type Curve Analysis (see).
NPDES:	National Pollutant Discharge Elimination System.
NSCR:	Non-Selective Catalytic Reduction.
NSPS:	New Source Performance Standards.
NTNC:	Non- transient non-community.
NWS:	National Weather Service.
NYCDEP:	New York City Department of Environmental Protection.
NYCRR:	New York Codes of Rules and Regulations.
NYSDAM:	New York State Department of Agriculture and Markets.
NYSDOH:	New York State Department of Health.
NYSDOT:	New York State Department of Transportation.

Term	Definition
NYSERDA:	New York State Energy Research and Development Authority.
O_3:	Ozone.
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 from 520 to 465 million years ago.
PADEP:	Pennsylvania Department of Environmental Protection.
Paleozoic Era:	Large block of geologic time from 570 to 225 million years ago; beginning marked by the appearance of abundant fossils. Most of the bedrock in New York State was formed (deposited) during the Paleozoic.
Parameter:	A characteristic of a model of a reservoir that may or may not vary with respect to position or with time. (e.g., porosity is a petrophysical parameter (or characteristic) that varies with position).
Partial Reclamation:	The reclamation of a well site following completion of a well and in the case of multi-well pad, completion of the last well on the multi-well pad. This includes the reclamation of pits, regarding of lands and the revegetation of lands outside the well pad.
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).
PBS:	Petroleum Bulk Storage.
PCC:	Pre-ignition Chamber Combustion.
Pennsylvanian Period:	Period of geologic time from 310 to 280 million years ago.
Percolation Test:	Test to determine at what rate fluids will pass through soil.

Term	Definition
Perennial Stream:	A stream channel that has continuous flow in parts of its bed all year round during years of normal rainfall.
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.
Perforation:	A hole created in the casing to achieve efficient communication between the reservoir and the wellbore.
Permeability:	A measure of a material's ability to allow passage of gas or liquid through pores, fractures, or other openings. The unit of measurement is the millidarcy.
Permeable:	Able to transmit gas or liquid through interconnected pores, fractures, or other openings.
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.
Pipe Racks:	Horizontal supports for storing tubular goods.
Plat:	A map of land parcels; a drafted map of a site's location showing boundaries of adjoining parcels.
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 prepare a well to be closed permanently with cement plugs, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir.
PM10 and PM2.5:	Particulate matter with sizes of less than 10 and 2.5 microns, respectively.
Pneumatic:	Run by or using compressed air.

Term	Definition
POC:	Principal Organic Contaminant.
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. Named for French mathematician Simeon Poisson (1781 to 1840).
Polymer:	Chemical compound of unusually high molecular weight composed of numerous repeated, linked molecular units.
Pool:	An underground reservoir containing a common accumulation of oil and/or gas. Each zone of a structure which is completely separated from any other zone in the same structure is a pool.
Porosity:	Volume of pore space expressed as a percent of the total bulk volume of the rock.
Potable Fresh Water:	Suitable for drinking by humans and containing less than 250 ppm of sodium chloride or 1,000 ppm TDS.
POTW:	Publicly Owned Treatment Works.
ppb:	Parts per billion.
ppm:	Parts per million.
Precambrian Era:	Very large block of geologic time spanning from Earth’s formation to the 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:	A highly productive aquifer presently being utilized as a source of water supply by a major municipal supply system.
Primary Carrier Fluid:	The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid which transports proppant.
Primary Production:	Production of a reservoir by natural energy in the reservoir.

Term	Definition
Principal Aquifer:	An aquifer known to be highly productive or whose geology suggests abundant potential water supply, but which is not intensively used as a source of water supply by a major municipal system.
Principal Stresses:	Forces per unit area acting on the external surface of a solid body.
Product:	A hydraulic fracturing fluid additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.
Production Casing:	Casing set above or through the producing zone through which the well produces.
Production Brine:	Liquids co-produced during oil and gas wells production.
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.
Public Water Supply:	Either a community or non-community well system which provides piped water to the public for human consumption if the system has a minimum of five (5) service connections, or regularly serves a minimum average of 25 individuals per day at least 60 days per year.
PTE:	Potential to Emit.
Pump and Plug Method:	A technique for placing cement plugs at appropriate intervals.
PVC:	Polyvinylchloride; a durable petroleum derived plastic.

Term	Definition
RACT:	Reasonably Available Control Technology.
Radial Cement Bond Log:	A record of sonic amplitudes derived from acoustic signals passing along the well casing. Used to evaluate cement-to-pipe and cement-to-formation bonding.
RCRA:	Resource Conservation and Recovery Act.
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.
Remediation:	The removal of pollution or contaminants from the environmental media such as soil, groundwater, or surface water.
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. In NY it is required to be lined with plastic to prevent soil contamination.
Reservoir (oil or gas):	A subsurface, porous, permeable or naturally fractured rock body in which oil or gas has accumulated. A gas and production is only gas plus fresh water that condenses from the flow stream reservoir. In a gas condensate reservoir, the hydrocarbons may exist as a gas, but, when brought to the surface, some of the heavier hydrocarbons condense and become a liquid.
Reservoir (water):	Any man-made structure used to supply fresh water to the public.
Reservoir Rock:	A rock that may contain oil or gas in appreciable quantity and through which petroleum may migrate.
RO:	Reverse Osmosis.
Rotary Rig:	A derrick equipped with rotary equipment where a well is drilled using rotational movement.
Royalty:	The landowner’s share of the value of oil and gas produced.

Term	Definition
Run-Off:	The portion of precipitation on land that ultimately reaches streams sometimes with dissolved or suspended material.
Sandstone:	A variously colored sedimentary rock composed chiefly of sandlike quartz grains cemented by lime, silica or other materials.
SAPA:	State Administrative Procedures Act.
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.
SCR:	Selective Catalytic Reduction.
SDWA:	Safe Drinking Water Act.
SDWIS:	Safe Drinking Water Information System.
Sedimentary:	Rocks formed from sediment transported from their source and deposited in water or by precipitation from solution or from secretions of organisms.
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.
SEIS:	Supplemental Environmental Impact Statement.
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.

Term	Definition
Setback:	Minimum distance required between a well operation and other zones, boundaries, or objects such as highways, wetlands, streams, or houses.
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:	A thinly laminated claystone, siltstone or mud stone.
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 propagates. 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.
SI:	Spark Ignition.
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.
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.

Term	**Definition**
Siltstone:	Rock in which the constituent particles are predominantly silt size.
Silurian Period:	Period of geologic time from 405 to 415 million years ago.
SIP	State Implementation Plan
Slickwater Fracturing (or slick-water):	A type of hydraulic fracturing which utilizes water-based fracturing fluid mixed with a friction reducing agent & other chemical additives. The fluid is typically 98% fresh water & sand (proppant) & 2% or less chemical additives.
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.
SO_2:	Sulfur dioxide.
SO_3	Sulfur trioxide.
Sonic Log:	See “Dipole Sonic Log”.
Spacing Unit:	A surface 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.
Spring:	A place where groundwater naturally flows from underground 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.

Term	Definition
Stage:	Isolation of a specific interval of the wellbore and the associated interval of the formation for the purpose of maintaining sufficient fracturing pressure.
Stage Plug:	A device used to mechanically isolate a specific interval of the wellbore and the formation for the purpose of maintaining sufficient fracturing pressure.
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.
Stimulation:	The act of increasing a well's productivity by artificial means such as hydraulic fracturing, acidizing, and shooting.
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.
Stratigraphy:	The study of rock layering, including the history, composition, relative ages and distribution of different rock units.
Stratum (plural strata):	Sedimentary rock layer, typically referred to as a formation, member, or bed.
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.
Substructure:	The foundation on which the derrick and drawworks sit. It contains space for storage and well-control equipment.
Surface Casing:	Casing extending from the surface through the potable fresh water zone.
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 a combination of other geosynthetic materials.

Term	Definition
Surfactants:	Chemical additives that reduce surface tension; or a surface active substance. Detergent is a surfactant.
SWPPP:	Stormwater Pollution Prevention Plan.
SWTR:	Surface Water Treatment Rule.
Target Formation:	The reservoir that the driller is trying to reach when drilling the well.
TCEQ:	Texas Commission on Environmental Quality.
Tcf:	Trillion cubic feet.
TD:	Total depth.
TDS:	Total Dissolved Solids. The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in mg/L or ppm.
TEG:	Triethylene Glycol.
Tensile Strength:	The force per unit cross-sectional area required to pull a substance apart.
Tight Formation:	Formation with very low permeability.
TMD:	Total measured depth.
TNC:	Transient non-community (in the context of water systems) or The Nature Conservancy.
TOC:	Total Organic Carbon.
Total Kjeldahl Nitrogen:	The sum of organic nitrogen; ammonium NH_3 and ammonia NH_4+ in water and soil analyses.
Tote:	A container used in the storage of various solid powder or liquid bulk products.
Trap:	Any geological barrier which restricts the migration of oil & gas.
TVD:	True vertical depth.

Term	Definition
Turbidity:	Amount of suspended solids in a liquid.
UA:	Urbanized areas.
UC:	Urban clusters.
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.
ULSF:	Ultra-Low Sulfur (Diesel) Fuel.
UN:	United Nations.
Unfiltered Surface Water Supplies:	Those that the U.S. EPA and NYSDOH have determined meet the requirements of the “Interim Enhanced Surface Water Treatment Rule” (IESWT Rule) for unfiltered water supply systems. The IESWT Rule is a December 16, 1998 amendment to the Surface Water Treatment Rule that was originally promulgated by EPA on June 29, 1989. In New York State, this includes the NYC Drinking Water Supply Watershed and the Skaneateles Drinking Water Supply Watershed.
UOC:	Unspecified Organic Contaminant.
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.
Water Well:	Any residential well used to supply potable water.
USEPA:	United States Environmental Protection Agency.

Term	**Definition**
USGS:	United States Geological Survey.
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.
VMT:	Vehicle Miles per Trip.
VOC:	Volatile Organic Compound.
Watershed:	The region drained by, or contributing water to, a stream, lake, or other body of water.
Well Location Plat:	A map of parcels of land with the proposed well and other features, particularly adjoining parcel boundaries.
Well Pad:	The area directly disturbed during drilling and operation of a gas well.
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.
Wellhead:	The equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casinghead and tubing head.
Well site:	Includes the well pad and access roads, equipment storage and staging areas, vehicle turnarounds, and any other areas directly or indirectly impacted by activities involving a well.
Wetland:	Any area regulated pursuant to Part 663.
Wildcat:	Well drilled to discover a previously unknown oil or gas pool or a well drilled one mile or more from a producing well.

Term	**Definition**
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.
WMA:	Wildlife Management Area.
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.
Workover:	Repair operations on a producing well to restore or increase production.
ZLD:	Zero liquid discharge.
Zonal Isolation:	The state of keeping fluids in one zone separate from the fluids in another zone. In the case of a well, isolation is maintained by appropriate use of casing, cement, plugs and packers.
Zone:	A rock stratum of different character or fluid content from other strata.

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SGEIS Bibliography

Final

Supplemental Generic Environmental Impact Statement

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NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Appendices

FINAL
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Regulatory Program for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

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[1] Updated/revised 2015

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New York State of Opportunity | Department of Environmental Conservation

Appendix 1

FEMA
Flood Insurance Rate Map
Availability

Excerpted from Alpha Environmental, 2009
Updated by NYSDEC

Final

Supplemental Generic Environmental Impact Statement

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TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ALBANY COUNTY	ALBANY, CITY OF	04/15/1980
ALBANY COUNTY	ALTAMONT, VILLAGE OF	08/15/1983
ALBANY COUNTY	BERNE,TOWN OF	08/01/1987 (L)
ALBANY COUNTY	BETHLEHEM, TOWN OF	04/17/1984
ALBANY COUNTY	COEYMANS, TOWN OF	08/03/1989
ALBANY COUNTY	COHOES, CITY OF	12/4/1979
ALBANY COUNTY	COLONIE, TOWN OF	09/05/1979
ALBANY COUNTY	GREEN ISLAND, VILLAGE OF	06/04/1980
ALBANY COUNTY	GUILDERLAND, TOWN OF	01/06/1983
ALBANY COUNTY	KNOX, TOWNSHIP OF	08/13/1982 (M)
ALBANY COUNTY	MENANDS, VILLAGE OF	03/18/1980
ALBANY COUNTY	NEW SCOTLAND, TOWN OF	12/1/1982
ALBANY COUNTY	RAVENA, VILLAGE OF	04/02/1982 (M)
ALBANY COUNTY	RENSSELAERVILLE, TOWN OF	08/27/1982 (M)
ALBANY COUNTY	VOORHEESVILLE, VILLAGE OF	12/1/1982
ALBANY COUNTY	WATERVLIET, CITY OF	01/02/1980
ALBANY COUNTY	WESTERLO, TOWN OF	08/03/1989
ALLEGANY COUNTY	ALFRED, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	ALFRED, VILLAGE OF	02/15/1980
ALLEGANY COUNTY	ALLEN, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	ALMA, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	ALMOND, VILLAGE OF	02/15/1980
ALLEGANY COUNTY	AMITY, TOWN OF	12/18/1984
ALLEGANY COUNTY	ANDOVER, TOWN OF	03/02/1998
ALLEGANY COUNTY	ANDOVER, VILLAGE OF	04/02/1979
ALLEGANY COUNTY	ANGELICA, TOWN OF	12/31/1982 (M)
ALLEGANY COUNTY	ANGELICA, VILLAGE OF	02/01/1984
ALLEGANY COUNTY	BELFAST, TOWN OF	08/06/1982 (M)
ALLEGANY COUNTY	BELMONT, VILLAGE OF	12/18/1984
ALLEGANY COUNTY	BIRDSALL, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	BOLIVAR, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	BOLIVAR, VILLAGE OF	01/19/1996
ALLEGANY COUNTY	BURNS, TOWN OF	07/16/1982 (M)
ALLEGANY COUNTY	CANASERAGA, VILLAGE OF	12/02/1983 (M)
ALLEGANY COUNTY	CANEADEA, TOWN OF	08/20/1982 (M)
ALLEGANY COUNTY	CLARKSVILLE, TOWN OF	11/12/1982 (M)
ALLEGANY COUNTY	CUBA, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	CUBA, VILLAGE OF	04/17/1978
ALLEGANY COUNTY	FRIENDSHIP, TOWN OF	12/18/1984
ALLEGANY COUNTY	GENESEE, TOWN OF	07/30/1982 (M)
ALLEGANY COUNTY	GRANGER, TOWN OF	10/07/1983 (M)
ALLEGANY COUNTY	GROVE, TOWN OF	11/6/1991
ALLEGANY COUNTY	HUME, TOWN OF	10/2/1997
ALLEGANY COUNTY	INDEPENDENCE, TOWN OF	07/09/1982 (M)
ALLEGANY COUNTY	NEW HUDSON, TOWN OF	08/20/1982 (M)
ALLEGANY COUNTY	RICHBURG, VILLAGE OF	01/05/1978
ALLEGANY COUNTY	RUSHFORD, TOWN OF	12/23/1983 (M)
ALLEGANY COUNTY	SCIO, TOWN OF	03/18/1985

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ALLEGANY COUNTY	WARD,TOWN OF	(NSFHA)
ALLEGANY COUNTY	WELLSVILLE, TOWN OF	03/18/1985
ALLEGANY COUNTY	WELLSVILLE, VILLAGE OF	07/17/1978
ALLEGANY COUNTY	WEST ALMOND, TOWN OF	(NSFHA)
ALLEGANY COUNTY	WILLING, TOWN OF	12/24/1982 (M)
ALLEGANY COUNTY	WIRT, TOWN OF	06/25/1982 (M)
BROOME COUNTY	BARKER, TOWN OF	02/05/1992
BROOME COUNTY	BINGHAMTON, CITY OF	06/01/1977
BROOME COUNTY	BINGHAMTON, TOWN OF	01/06/1984 (M)
BROOME COUNTY	CHENANGO, TOWN OF	08/17/1981
BROOME COUNTY	COLESVILLE, TOWN OF	01/20/1993
BROOME COUNTY	CONKLIN, TOWN OF	07/17/1981
BROOME COUNTY	DICKINSON, TOWN OF	04/15/1977
BROOME COUNTY	ENDICOTT, VILLAGE OF	09/07/1998
BROOME COUNTY	FENTON, TOWN OF	08/03/1981
BROOME COUNTY	JOHNSON CITY, VILLAGE OF	09/30/1977
BROOME COUNTY	KIRKWOOD, TOWN OF	06/01/1977
BROOME COUNTY	LISLE, TOWN OF	08/20/2002
BROOME COUNTY	LISLE, VILLAGE OF	01/06/1984 (M)
BROOME COUNTY	MAINE, TOWN OF	02/05/1992
BROOME COUNTY	NANTICOKE, TOWN OF	12/18/1985
BROOME COUNTY	PORT DICKINSON, VILLAGE OF	05/02/1977
BROOME COUNTY	SANFORD, TOWN OF	06/04/1980
BROOME COUNTY	TRIANGLE, TOWN OF	07/20/1984 (M)
BROOME COUNTY	UNION, TOWN OF	09/30/1988
BROOME COUNTY	VESTAL, TOWN OF	03/02/1998
BROOME COUNTY	WHITNEY POINT, VILLAGE OF	01/06/1984 (M)
BROOME COUNTY	WINDSOR, TOWN OF	09/30/1992
BROOME COUNTY	WINDSOR, VILLAGE OF	05/18/1992
CATTARAUGUS COUNTY	ALLEGANY, TOWN OF	11/15/1978
CATTARAUGUS COUNTY	ALLEGANY, VILLAGE OF	12/17/1991
CATTARAUGUS COUNTY	ASHFORD, TOWNSHIP OF	05/25/1984
CATTARAUGUS COUNTY	CARROLLTON, TOWN OF	03/18/1983 (M)
CATTARAUGUS COUNTY	CATTARAUGUS, VILLAGE OF	04/20/1984 (M)
CATTARAUGUS COUNTY	COLD SPRING, TOWN OF	03/01/1978
CATTARAUGUS COUNTY	CONEWANGO, TOWN OF	07/30/1982 (M)
CATTARAUGUS COUNTY	DAYTON, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY	DELEVAN, VILLAGE OF	01/20/1984 (M)
CATTARAUGUS COUNTY	EAST OTTO, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	EAST RANDOLPH, VILLAGE OF	02/01/1978
CATTARAUGUS COUNTY	ELLICOTTVILLE, TOWN OF	01/19/2000
CATTARAUGUS COUNTY	ELLICOTTVILLE, VILLAGE OF	05/02/1994
CATTARAUGUS COUNTY	FARMERSVILLE, TOWN OF	07/23/1982 (M)
CATTARAUGUS COUNTY	FRANKLINVILLE, TOWN OF	07/17/1978
CATTARAUGUS COUNTY	FRANKLINVILLE, VILLAGE OF	07/03/1978
CATTARAUGUS COUNTY	FREEDOM, TOWN OF	08/19/1991
CATTARAUGUS COUNTY	GREAT VALLEY, TOWN OF	07/17/1978
CATTARAUGUS COUNTY	HINSDALE, TOWN OF	01/17/1979

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CATTARAUGUS COUNTY	HUMPHREY, TOWN OF	08/13/1982 (M)
CATTARAUGUS COUNTY	ISCHUA, TOWN OF	08/15/1978
CATTARAUGUS COUNTY	LEON, TOWN OF	08/13/1982 (M)
CATTARAUGUS COUNTY	LIMESTONE, VILLAGE OF	04/17/1978
CATTARAUGUS COUNTY	LITTLE VALLEY, TOWN OF	06/22/1984 (M)
CATTARAUGUS COUNTY	LITTLE VALLEY, VILLAGE OF	02/01/1978
CATTARAUGUS COUNTY	LYNDON, TOWN OF	07/16/1982 (M)
CATTARAUGUS COUNTY	MACHIAS, TOWN OF	08/20/1982 (M)
CATTARAUGUS COUNTY	MANSFIELD, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY	NAPOLI, TOWN OF	07/02/1982 (M)
CATTARAUGUS COUNTY	NEW ALBION, TOWN OF	12/03/1982 (M)
CATTARAUGUS COUNTY	OLEAN, CITY OF	05/09/1980
CATTARAUGUS COUNTY	OLEAN, TOWN OF	02/01/1979
CATTARAUGUS COUNTY	OTTO, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PERRYSBURG, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PERSIA, TOWN OF	04/20/1984 (M)
CATTARAUGUS COUNTY	PORTVILLE, TOWN OF	07/18/1983
CATTARAUGUS COUNTY	PORTVILLE, VILLAGE OF	04/17/1978
CATTARAUGUS COUNTY	RANDOLPH, TOWN OF	11/05/1982 (M)
CATTARAUGUS COUNTY	RANDOLPH, VILLAGE OF	08/01/1978
CATTARAUGUS COUNTY	SALAMANCA, CITY OF	04/17/1978
CATTARAUGUS COUNTY	SALAMANCA, TOWN OF	11/1/1979
CATTARAUGUS COUNTY	SOUTH DAYTON, VILLAGE OF	01/05/1978
CATTARAUGUS COUNTY	SOUTH VALLEY, TOWN OF	12/02/1983 (M)
CATTARAUGUS COUNTY	YORKSHIRE, TOWN OF	05/25/1984 (M)
CATTARAUGUS COUNTY/ERIE COUNTY/CHAUTAUQUA COUNTY/ALLEGANY COUNTY	SENECA NATION OF INDIANS	09/30/1988
CAYUGA COUNTY	AUBURN, CITY OF	08/02/2007
CAYUGA COUNTY	AURELIUS, TOWN OF	08/02/2007
CAYUGA COUNTY	AURORA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	BRUTUS, TOWN OF	08/02/2007
CAYUGA COUNTY	CATO, TOWN OF	08/02/2007
CAYUGA COUNTY	CATO, VILLAGE OF	08/02/2007
CAYUGA COUNTY	CAYUGA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	CONQUEST, TOWN OF	08/02/2007
CAYUGA COUNTY	FAIR HAVEN, VILLAGE OF	08/02/2007
CAYUGA COUNTY	FLEMING, TOWN OF	08/02/2007
CAYUGA COUNTY	GENOA,TOWN OF	08/02/2007
CAYUGA COUNTY	IRA, TOWN OF	08/02/2007
CAYUGA COUNTY	LEDYARD, TOWN OF	08/02/2007
CAYUGA COUNTY	LOCKE, TOWN OF	08/02/2007
CAYUGA COUNTY	MENTZ, TOWN OF	08/02/2007
CAYUGA COUNTY	MERIDIAN, VILLAGE OF	08/02/2007
CAYUGA COUNTY	MONTEZUMA, TOWN OF	08/02/2007
CAYUGA COUNTY	MORAVIA, TOWN OF	08/02/2007
CAYUGA COUNTY	MORAVIA, VILLAGE OF	08/02/2007
CAYUGA COUNTY	NILES, TOWN OF	08/02/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CAYUGA COUNTY	OWASCO, TOWN OF	08/02/2007
CAYUGA COUNTY	PORT BYRON, VILLAGE OF	08/02/2007
CAYUGA COUNTY	SCIPIO, TOWN OF	08/02/2007
CAYUGA COUNTY	SEMPRONIUS, TOWN OF	08/02/2007
CAYUGA COUNTY	SENNETT, TOWN OF	08/02/2007
CAYUGA COUNTY	SPRINGPORT, TOWN OF	08/02/2007
CAYUGA COUNTY	STERLING, TOWN OF	08/02/2007
CAYUGA COUNTY	SUMMER HILL, TOWN OF	08/02/2007
CAYUGA COUNTY	THROOP, TOWN OF	08/02/2007
CAYUGA COUNTY	UNION SPRINGS, VILLAGE OF	08/02/2007
CAYUGA COUNTY	VENICE, TOWN OF	08/02/2007
CAYUGA COUNTY	VICTORY, TOWN OF	08/02/2007
CAYUGA COUNTY	WEEDSPORT, VILLAGE OF	08/02/2007
CHAUTAUQUA COUNTY	ARKWRIGHT, TOWN OF	04/08/1983 (M)
CHAUTAUQUA COUNTY	BEMUS POINT, VILLAGE OF	11/2/1977
CHAUTAUQUA COUNTY	BROCTON, VILLAGE OF	(NSFHA)
CHAUTAUQUA COUNTY	BUSTI, TOWN OF	01/20/1993
CHAUTAUQUA COUNTY	CARROLL, TOWN OF	10/29/1982 (M)
CHAUTAUQUA COUNTY	CASSADAGA, VILLAGE OF	12/1/1977
CHAUTAUQUA COUNTY	CELORON, VILLAGE OF	03/18/1980
CHAUTAUQUA COUNTY	CHARLOTTE, TOWN OF	03/23/1984 (M)
CHAUTAUQUA COUNTY	CHAUTAUQUA, TOWN OF	06/15/1984
CHAUTAUQUA COUNTY	CHERRY CREEK, TOWN OF	07/02/1982 (M)
CHAUTAUQUA COUNTY	CHERRY CREEK, VILLAGE OF	02/15/1978
CHAUTAUQUA COUNTY	CLYMER, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	DUNKIRK, CITY OF	02/04/1981
CHAUTAUQUA COUNTY	DUNKIRK, TOWN OF	08/06/1982 (M)
CHAUTAUQUA COUNTY	ELLERY, TOWN OF	03/18/1980
CHAUTAUQUA COUNTY	ELLICOTT, TOWN OF	08/01/1984
CHAUTAUQUA COUNTY	ELLINGTON, TOWN OF	10/07/1983(M)
CHAUTAUQUA COUNTY	FALCONER, VILLAGE OF	01/05/1978
CHAUTAUQUA COUNTY	FORESTVILLE, VILLAGE OF	03/18/1983(M)
CHAUTAUQUA COUNTY	FREDONIA, VILLAGE OF	11/15/1989
CHAUTAUQUA COUNTY	FRENCH CREEK, TOWN OF	06/08/1984 (M)
CHAUTAUQUA COUNTY	GERRY, TOWN OF	01/06/1984 (M)
CHAUTAUQUA COUNTY	HANOVER, TOWN OF	12/18/1984
CHAUTAUQUA COUNTY	HARMONY, TOWNSHIP OF	12/01/1986 (L)
CHAUTAUQUA COUNTY	JAMESTOWN, CITY OF	06/01/1978
CHAUTAUQUA COUNTY	KIANTONE, TOWN OF	02/02/1996
CHAUTAUQUA COUNTY	LAKEWOOD, VILLAGE OF	11/2/1977
CHAUTAUQUA COUNTY	MAYVILLE, VILLAGE OF	01/05/1978
CHAUTAUQUA COUNTY	MINA, TOWN OF	01/02/2003
CHAUTAUQUA COUNTY	NORTH HARMONY, TOWN OF	02/15/1980
CHAUTAUQUA COUNTY	PANAMA, VILLAGE OF	03/01/1978
CHAUTAUQUA COUNTY	POLAND, TOWN OF	03/11/1983 (M)
CHAUTAUQUA COUNTY	POMFRET, TOWN OF	12/18/1984
CHAUTAUQUA COUNTY	PORTLAND, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	RIPLEY,TOWN OF	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CHAUTAUQUA COUNTY	SHERIDAN, TOWN OF	10/07/1983 (M)
CHAUTAUQUA COUNTY	SHERMAN, VILLAGE OF	03/01/1978
CHAUTAUQUA COUNTY	SHERMAN,TOWN OF	01/06/1984 (M)
CHAUTAUQUA COUNTY	SILVER CREEK, VILLAGE OF	08/01/1983
CHAUTAUQUA COUNTY	SINCLAIRVILLE, VILLAGE OF	12/1/1977
CHAUTAUQUA COUNTY	STOCKTON, TOWN OF	10/21/1983 (M)
CHAUTAUQUA COUNTY	VILLENOVA, TOWN OF	05/21/1982 (M)
CHAUTAUQUA COUNTY	WESTFIELD, TOWN OF	06/08/1984 (M)
CHAUTAUQUA COUNTY	WESTFIELD, VILLAGE OF	10/07/1983 (M)
CHEMUNG COUNTY	ASHLAND, TOWN OF	01/16/1980
CHEMUNG COUNTY	BALDWIN, TOWN OF	07/23/1982 (M)
CHEMUNG COUNTY	BIG FLATS, TOWN OF	08/18/1992
CHEMUNG COUNTY	CATLIN, TOWN OF	06/22/1984 (M)
CHEMUNG COUNTY	CHEMUNG, TOWN OF	09/03/1980
CHEMUNG COUNTY	ELMIRA HEIGHTS, VILLAGE OF	09/29/1996
CHEMUNG COUNTY	ELMIRA, CITY OF	04/02/1997
CHEMUNG COUNTY	ELMIRA, TOWN OF	09/29/1996
CHEMUNG COUNTY	ERIN, TOWN OF	08/13/1982 (M)
CHEMUNG COUNTY	HORSEHEADS, TOWN OF	09/29/1996
CHEMUNG COUNTY	HORSEHEADS, VILLAGE OF	09/29/1996
CHEMUNG COUNTY	MILLPORT, VILLAGE OF	06/15/1988 (M)
CHEMUNG COUNTY	SOUTHPORT, TOWN OF	08/05/1991
CHEMUNG COUNTY	VAN ETTEN, TOWN OF	09/28/1979 (M)
CHEMUNG COUNTY	VAN ETTEN, VILLAGE OF	07/01/1988 (L)
CHEMUNG COUNTY	VETERAN, TOWN OF	02/18/1983 (M)
CHEMUNG COUNTY	WELLSBURG, VILLAGE OF	06/15/1981
CHENANGO COUNTY	AFTON, TOWN OF	11/26/2010
CHENANGO COUNTY	AFTON, VILLAGE OF	11/26/2010
CHENANGO COUNTY	BAINBRIDGE, TOWN OF	11/26/2010
CHENANGO COUNTY	BAINBRIDGE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	COLUMBUS, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	COVENTRY, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	EARLVILLE, VILLAGE OF	11/26/2010 (M)
CHENANGO COUNTY	GERMAN, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	GREENE, TOWN OF	11/26/2010
CHENANGO COUNTY	GREENE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	GUILFORD, TOWN OF	11/26/2010
CHENANGO COUNTY	LINCKLAEN, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	MC DONOUGH, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	NEW BERLIN, TOWN OF	11/26/2010
CHENANGO COUNTY	NEW BERLIN, VILLAGE OF	11/26/2010
CHENANGO COUNTY	NORTH NORWICH, TOWN OF	11/26/2010
CHENANGO COUNTY	NORWICH, CITY OF	11/26/2010
CHENANGO COUNTY	NORWICH, TOWN OF	11/26/2010
CHENANGO COUNTY	OTSELIC, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	OXFORD, TOWN OF	11/26/2010
CHENANGO COUNTY	OXFORD, VILLAGE OF	11/26/2010
CHENANGO COUNTY	PHARSALIA, TOWN OF	11/26/2010 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CHENANGO COUNTY	PITCHER, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	PLYMOUTH, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	PRESTON, TOWN OF	11/26/2010
CHENANGO COUNTY	SHERBURNE, TOWN OF	11/26/2010
CHENANGO COUNTY	SHERBURNE, VILLAGE OF	11/26/2010
CHENANGO COUNTY	SMITHVILLE, TOWN OF	11/26/2010 (M)
CHENANGO COUNTY	SMYRNA, TOWN OF	11/26/2010
CHENANGO COUNTY	SMYRNA, VILLAGE OF	11/26/2010 (M)
CLINTON COUNTY	ALTONA, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	AUSABLE, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	BEEKMANTOWN, TOWN OF	09/28/2007
CLINTON COUNTY	BLACK BROOK, TOWN OF	09/28/2007
CLINTON COUNTY	CHAMPLAIN, TOWN OF	09/28/2007
CLINTON COUNTY	CHAMPLAIN, VILLAGE OF	09/28/2007
CLINTON COUNTY	CHAZY, TOWN OF	09/28/2007
CLINTON COUNTY	CLINTON, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	ELLENBURG, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	MOOERS, TOWN OF	09/28/2007 (M)
CLINTON COUNTY	PERU,TOWN OF	09/28/2007
CLINTON COUNTY	PLATTSBURGH, CITY OF	09/28/2007
CLINTON COUNTY	PLATTSBURGH, TOWN OF	09/28/2007
CLINTON COUNTY	ROUSES POINT, VILLAGE OF	09/28/2007
CLINTON COUNTY	SARANAC, TOWN OF	09/28/2007
CLINTON COUNTY	SCHUYLER FALLS, TOWN OF	09/28/2007
COLUMBIA COUNTY	ANCRAM, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	AUSTERLITZ, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	CANAAN, TOWN OF	07/03/1985 (M)
COLUMBIA COUNTY	CHATHAM, TOWN OF	09/15/1993
COLUMBIA COUNTY	CHATHAM, VILLAGE OF	12/15/1982
COLUMBIA COUNTY	CLAVERACK, TOWN OF	09/06/1989
COLUMBIA COUNTY	CLERMONT, TOWNSHIP OF	09/05/1984
COLUMBIA COUNTY	COPAKE, TOWN OF	06/19/1985 (M)
COLUMBIA COUNTY	GALLATIN, TOWN OF	10/16/1984
COLUMBIA COUNTY	GERMANTOWN, TOWN OF	05/11/1979 (M)
COLUMBIA COUNTY	GHENT, TOWN OF	01/01/1988 (L)
COLUMBIA COUNTY	GREENPORT, TOWN OF	11/15/1989
COLUMBIA COUNTY	HILLSDALE, TOWN OF	05/15/1985 (M)
COLUMBIA COUNTY	HUDSON, CITY OF	09/29/1989
COLUMBIA COUNTY	KINDERHOOK, TOWN OF	12/1/1982
COLUMBIA COUNTY	KINDERHOOK, VILLAGE OF	12/1/1982
COLUMBIA COUNTY	LIVINGSTON, TOWN OF	05/11/1979 (M)
COLUMBIA COUNTY	NEW LEBANON, TOWN OF	06/05/1985 (M)
COLUMBIA COUNTY	STOCKPORT, TOWN OF	01/19/1983
COLUMBIA COUNTY	STUYVESANT, TOWN OF	09/14/1979 (M)
COLUMBIA COUNTY	TAGHKANIC, TOWN OF	01/03/1986 (M)
COLUMBIA COUNTY	VALATIE, VILLAGE OF	12/1/1982
CORTLAND COUNTY	CINCINNATUS, TOWN OF	03/02/2010
CORTLAND COUNTY	CORTLAND, CITY OF	03/02/2010

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
CORTLAND COUNTY	CORTLANDVILLE, TOWN OF	03/02/2010
CORTLAND COUNTY	CUYLER, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	FREETOWN, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	HARFORD, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	HOMER, TOWN OF	03/02/2010
CORTLAND COUNTY	HOMER, VILLAGE OF	03/02/2010
CORTLAND COUNTY	LAPEER, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	MARATHON, TOWN OF	03/02/2010
CORTLAND COUNTY	MARATHON, VILLAGE OF	03/02/2010
CORTLAND COUNTY	MCGRAW, VILLAGE OF	03/02/2010
CORTLAND COUNTY	PREBLE, TOWN OF	03/02/2010
CORTLAND COUNTY	SCOTT, TOWN OF	03/02/2010
CORTLAND COUNTY	SOLON, TOWN OF	03/02/2010
CORTLAND COUNTY	TAYLOR, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	TRUXTON, TOWN OF	03/02/2010 (M)
CORTLAND COUNTY	VIRGIL, TOWN OF	03/02/2010
CORTLAND COUNTY	WILLET, TOWN OF	03/02/2010 (M)
DELAWARE COUNTY	ANDES, TOWN OF	05/01/1985 (M)
DELAWARE COUNTY	ANDES, VILLAGE OF	04/01/1986 (L)
DELAWARE COUNTY	BOVINA, TOWN OF	05/01/1985 (M)
DELAWARE COUNTY	COLCHESTER,TOWN OF	02/04/1987
DELAWARE COUNTY	DAVENPORT, TOWN OF	02/02/2002
DELAWARE COUNTY	DELHI, TOWN OF	07/18/1985
DELAWARE COUNTY	DELHI, VILLAGE OF	07/18/1985
DELAWARE COUNTY	DEPOSIT, TOWN OF	03/18/1986 (M)
DELAWARE COUNTY	FLEISCHMANNS, VILLAGE OF	01/17/1986 (M)
DELAWARE COUNTY	FRANKLIN, TOWN OF	04/01/1988 (L)
DELAWARE COUNTY	FRANKLIN, VILLAGE OF	08/01/1987 (L)
DELAWARE COUNTY	HAMDEN,TOWN OF	03/04/1986 (M)
DELAWARE COUNTY	HANCOCK, TOWN OF	09/28/1990
DELAWARE COUNTY	HANCOCK, VILLAGE OF	09/28/1990
DELAWARE COUNTY	HARPERSFIELD, TOWN OF	06/05/1985 (M)
DELAWARE COUNTY	HOBART, VILLAGE OF	05/15/1985 (M)
DELAWARE COUNTY	KORTRIGHT, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	MARGARETVILLE, VILLAGE OF	06/04/1990
DELAWARE COUNTY	MASONVILLE, TOWN OF	11/01/1985 (M)
DELAWARE COUNTY	MEREDITH, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	MIDDLETOWN, TOWN OF	08/02/1993
DELAWARE COUNTY	ROXBURY, TOWN OF	05/15/1985 (M)
DELAWARE COUNTY	SIDNEY, TOWN OF	09/30/1987
DELAWARE COUNTY	SIDNEY, VILLAGE OF	09/30/1987
DELAWARE COUNTY	STAMFORD, TOWN OF	10/01/1986 (L)
DELAWARE COUNTY	STAMFORD, VILLAGE OF	08/01/1987 (L)
DELAWARE COUNTY	TOMPKINS, TOWN OF	11/15/1985 (M)
DELAWARE COUNTY	WALTON, TOWN OF	09/02/1988
DELAWARE COUNTY	WALTON, VILLAGE OF	04/02/1991
DELAWARE COUNTY/BROOME COUNTY	DEPOSIT, VILLAGE OF	02/01/1979
DUTCHESS COUNTY	AMENIA, TOWN OF	11/15/1989

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
DUTCHESS COUNTY	BEACON, CITY OF	03/01/1984
DUTCHESS COUNTY	BEEKMAN, TOWN OF	09/05/1984
DUTCHESS COUNTY	CLINTON, TOWN OF	07/05/1984
DUTCHESS COUNTY	DOVER, TOWN OF	07/04/1988
DUTCHESS COUNTY	EAST FISHKILL, TOWN OF	06/15/1984
DUTCHESS COUNTY	FISHKILL, TOWN OF	06/01/1984
DUTCHESS COUNTY	FISHKILL, VILLAGE OF	03/15/1984
DUTCHESS COUNTY	HYDE PARK, TOWN OF	06/15/1984
DUTCHESS COUNTY	LAGRANGE, TOWN OF	09/08/1999
DUTCHESS COUNTY	MILAN, TOWN OF	08/10/1979 (M)
DUTCHESS COUNTY	MILLBROOK, VILLAGE OF	02/27/1984 (M)
DUTCHESS COUNTY	MILLERTON, VILLAGE OF	01/03/1985
DUTCHESS COUNTY	NORTH EAST, TOWN OF	09/05/1984
DUTCHESS COUNTY	PAWLING, TOWN OF	01/03/1985
DUTCHESS COUNTY	PAWLING, VILLAGE OF	08/01/1984
DUTCHESS COUNTY	PINE PLAINS, TOWN OF	10/05/1984 (M)
DUTCHESS COUNTY	PLEASANT VALLEY, TOWN OF	01/16/1980
DUTCHESS COUNTY	POUGHKEEPSIE, CITY OF	01/05/1984
DUTCHESS COUNTY	POUGHKEEPSIE, TOWN OF	09/08/1999
DUTCHESS COUNTY	RED HOOK, TOWN OF	10/16/1984
DUTCHESS COUNTY	RED HOOK, VILLAGE OF	(NSFHA)
DUTCHESS COUNTY	RHINEBECK, TOWN OF	09/05/1984
DUTCHESS COUNTY	RHINEBECK, VILLAGE OF	02/01/1985
DUTCHESS COUNTY	STANFORD, TOWN OF	12/17/1991
DUTCHESS COUNTY	TIVOLI, VILLAGE OF	08/01/1984
DUTCHESS COUNTY	UNION VALE, TOWN OF	09/02/1988
DUTCHESS COUNTY	WAPPINGER, TOWN OF	09/22/1999
DUTCHESS COUNTY	WAPPINGERS FALLS, VILLAGE OF	09/22/1999
DUTCHESS COUNTY	WASHINGTON, TOWN OF	08/17/1979 (M)
ERIE COUNTY	AKRON, VILLAGE OF	11/19/1980
ERIE COUNTY	ALDEN, TOWN OF	02/06/1991
ERIE COUNTY	ALDEN, VILLAGE OF	01/06/1984 (M)
ERIE COUNTY	AMHERST, TOWN OF	10/16/1992
ERIE COUNTY	ANGOLA, VILLAGE OF	08/06/2002
ERIE COUNTY	AURORA, TOWN OF	04/16/1979
ERIE COUNTY	BLASDELL, VILLAGE OF	06/25/1976 (M)
ERIE COUNTY	BOSTON, TOWN OF	09/30/1981
ERIE COUNTY	BRANT, TOWN OF	01/06/1984 (M)
ERIE COUNTY	BUFFALO, CITY OF	09/26/2008
ERIE COUNTY	CHEEKTOWAGA, TOWN OF	03/15/1984
ERIE COUNTY	CLARENCE, TOWN OF	03/05/1996
ERIE COUNTY	COLDEN, TOWN OF	07/02/1979
ERIE COUNTY	COLLINS,TOWN OF	09/26/2008
ERIE COUNTY	CONCORD, TOWN OF	09/04/1986
ERIE COUNTY	DEPEW, VILLAGE OF	08/03/1981
ERIE COUNTY	EAST AURORA, VILLAGE OF	08/06/2002
ERIE COUNTY	EDEN, TOWN OF	08/24/1979 (M)
ERIE COUNTY	ELMA,TOWN OF	06/22/1998

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ERIE COUNTY	EVANS, TOWN OF	02/02/2002
ERIE COUNTY	FARNHAM, VILLAGE OF	(NSFHA)
ERIE COUNTY	GRAND ISLAND, TOWN OF	09/26/2008
ERIE COUNTY	HAMBURG, TOWN OF	12/20/2001
ERIE COUNTY	HAMBURG, VILLAGE OF	01/20/1982
ERIE COUNTY	HOLLAND, TOWN OF	09/26/2008
ERIE COUNTY	KENMORE,VILLAGE OF	(NSFHA)
ERIE COUNTY	LACKAWANNA, CITY OF	07/02/1980
ERIE COUNTY	LANCASTER, TOWN OF	02/23/2001
ERIE COUNTY	LANCASTER, VILLAGE OF	07/02/1979
ERIE COUNTY	MARILLA, TOWN OF	09/29/1978
ERIE COUNTY	NEWSTEAD, TOWN OF	05/04/1992
ERIE COUNTY	ORCHARD PARK, TOWN OF	03/16/1983
ERIE COUNTY	ORCHARD PARK, VILLAGE OF	(NSFHA)
ERIE COUNTY	SARDINIA, TOWN OF	01/16/2003
ERIE COUNTY	SLOAN, VILLAGE OF	(NSFHA)
ERIE COUNTY	SPRINGVILLE, VILLAGE OF	07/17/1986
ERIE COUNTY	TONAWANDA, CITY OF	09/26/2008
ERIE COUNTY	TONAWANDA, TOWN OF	11/12/1982
ERIE COUNTY	WALES, TOWN OF	09/26/2008
ERIE COUNTY	WEST SENECA, TOWN OF	09/30/1992
ERIE COUNTY	WILLIAMSVILLE, VILLAGE OF	09/26/2008
ERIE COUNTY/CATTARAUGUS COUNTY	GOWANDA, VILLAGE OF	09/26/2008
ESSEX COUNTY	CHESTERFIELD, TOWN OF	05/04/1987
ESSEX COUNTY	CROWN POINT,TOWN OF	07/16/1987
ESSEX COUNTY	ELIZABETHTOWN, TOWN OF	01/20/1993
ESSEX COUNTY	ESSEX, TOWN OF	04/03/1987
ESSEX COUNTY	JAY, TOWN OF	06/17/2002
ESSEX COUNTY	KEENE, TOWN OF	06/05/1985 (M)
ESSEX COUNTY	KEESEVILLE, VILLAGE OF	09/28/2007 (M)
ESSEX COUNTY	LAKE PLACID, VILLAGE OF	(NSFHA)
ESSEX COUNTY	LEWIS, TOWN OF	05/15/1985 (M)
ESSEX COUNTY	MINERVA, TOWN OF	10/05/1984 (M)
ESSEX COUNTY	MORIAH, TOWN OF	09/24/1984 (M)
ESSEX COUNTY	NEWCOMB, TOWN OF	06/05/1985 (M)
ESSEX COUNTY	NORTH ELBA, TOWN OF	08/23/2001
ESSEX COUNTY	NORTH HUDSON, TOWN OF	05/15/1985 (M)
ESSEX COUNTY	PORT HENRY, VILLAGE OF	07/16/1987
ESSEX COUNTY	SCHROON, TOWN OF	11/16/1995
ESSEX COUNTY	ST. ARMAND, TOWN OF	02/05/1986
ESSEX COUNTY	TICONDEROGA, TOWN OF	09/06/1996
ESSEX COUNTY	WESTPORT, TOWN OF	09/04/1987
ESSEX COUNTY	WILLSBORO, TOWN OF	05/18/1992
ESSEX COUNTY	WILMINGTON, TOWN OF	11/16/1995
FRANKLIN COUNTY	BANGOR, TOWN OF	(NSFHA)
FRANKLIN COUNTY	BELLMONT, TOWN OF	08/05/1985 (M)
FRANKLIN COUNTY	BOMBAY, TOWN OF	02/15/1985 (M)
FRANKLIN COUNTY	BRANDON, TOWN OF	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
FRANKLIN COUNTY	BRIGHTON, TOWN OF	(NSFHA)
FRANKLIN COUNTY	BRUSHTON, VILLAGE OF	02/19/1986 (M)
FRANKLIN COUNTY	BURKE, TOWN OF	02/19/1986 (M)
FRANKLIN COUNTY	BURKE, VILLAGE OF	(NSFHA)
FRANKLIN COUNTY	CHATEAUGAY, VILLAGE OF	(NSFHA)
FRANKLIN COUNTY	CONSTABLE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	DICKINSON, TOWN OF	03/18/1986 (M)
FRANKLIN COUNTY	DUANE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	FORT COVINGTON, TOWN OF	12/23/1983 (M)
FRANKLIN COUNTY	FRANKLIN, TOWN OF	09/24/1984 (M)
FRANKLIN COUNTY	HARRIETSTOWN, TOWN OF	01/03/1985
FRANKLIN COUNTY	MALONE, TOWN OF	09/04/1985 (M)
FRANKLIN COUNTY	MALONE, VILLAGE OF	04/03/1978
FRANKLIN COUNTY	MOIRA, TOWN OF	04/15/1986 (M)
FRANKLIN COUNTY	SANTA CLARA, TOWN OF	(NSFHA)
FRANKLIN COUNTY	SARANAC LAKE, VILLAGE OF	01/02/1992
FRANKLIN COUNTY	TUPPER LAKE, TOWN OF	(NSFHA)
FRANKLIN COUNTY	TUPPER LAKE,VILLAGE OF	03/01/1987 (L)
FRANKLIN COUNTY	WAVERLY, TOWN OF	(NSFHA)
FRANKLIN COUNTY	WESTVILLE, TOWN OF	02/15/1985 (M)
FULTON COUNTY	BLEECKER,TOWN OF	07/18/1985 (M)
FULTON COUNTY	BROADALBIN, TOWN OF	01/03/1985 (M)
FULTON COUNTY	BROADALBIN, VILLAGE OF	04/15/1986 (M)
FULTON COUNTY	CAROGA, TOWN OF	07/18/1985 (M)
FULTON COUNTY	EPHRATAH, TOWN OF	07/03/1985 (M)
FULTON COUNTY	GLOVERSVILLE, CITY OF	09/30/1983
FULTON COUNTY	JOHNSTOWN, CITY OF	07/18/1983
FULTON COUNTY	JOHNSTOWN, TOWN OF	07/03/1985 (M)
FULTON COUNTY	MAYFIELD, TOWN OF	08/05/1985 (M)
FULTON COUNTY	NORTHAMPTON, TOWN OF	08/19/1985 (M)
FULTON COUNTY	NORTHVILLE, VILLAGE OF	(NSFHA)
FULTON COUNTY	OPPENHEIM, TOWN OF	06/18/1976
FULTON COUNTY	PERTH, TOWN OF	02/15/1985 (M)
FULTON COUNTY	STRATFORD, TOWN OF	01/03/1985 (M)
GENESEE COUNTY	ALABAMA, TOWN OF	11/18/1983 (M)
GENESEE COUNTY	ALEXANDER, VILLAGE OF	05/04/1987
GENESEE COUNTY	ALEXANDER,TOWN OF	05/04/1987
GENESEE COUNTY	BATAVIA, CITY OF	09/16/1982
GENESEE COUNTY	BATAVIA, TOWN OF	01/17/1985
GENESEE COUNTY	BERGEN, TOWN OF	07/06/1984 (M)
GENESEE COUNTY	BERGEN, VILLAGE OF	06/08/1979 (M)
GENESEE COUNTY	BETHANY, TOWN OF	09/24/1984 (M)
GENESEE COUNTY	BYRON, TOWN OF	02/01/1988 (L)
GENESEE COUNTY	CORFU, VILLAGE OF	10/15/1985 (M)
GENESEE COUNTY	DARIEN, TOWN OF	07/06/1984 (M)
GENESEE COUNTY	ELBA, TOWN OF	10/05/1984 (M)
GENESEE COUNTY	ELBA, VILLAGE OF	01/20/1984 (M)
GENESEE COUNTY	LE ROY, TOWN OF	09/14/1979 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
GENESEE COUNTY	LE ROY, VILLAGE OF	08/03/1981
GENESEE COUNTY	OAKFIELD, TOWN OF	05/25/1984 (M)
GENESEE COUNTY	OAKFIELD, VILLAGE OF	03/23/1984 (M)
GENESEE COUNTY	PAVILION, TOWN OF	02/27/1984 (M)
GENESEE COUNTY	PEMBROKE, TOWN OF	01/20/1984 (M)
GENESEE COUNTY	STAFFORD,TOWN OF	07/16/1982
GENESEE COUNTY/WYOMING COUNTY	ATTICA, VILLAGE OF	07/03/1986
GREENE COUNTY	ASHLAND, TOWN OF	05/16/2008
GREENE COUNTY	ATHENS, TOWN OF	05/16/2008
GREENE COUNTY	ATHENS, VILLAGE OF	05/16/2008
GREENE COUNTY	CAIRO, TOWN OF	05/16/2008
GREENE COUNTY	CATSKILL, TOWN OF	05/16/2008
GREENE COUNTY	CATSKILL, VILLAGE OF	05/16/2008
GREENE COUNTY	COXSACKIE, TOWN OF	05/16/2008
GREENE COUNTY	COXSACKIE, VILLAGE OF	05/16/2008
GREENE COUNTY	DURHAM, TOWN OF	05/16/2008 (M)
GREENE COUNTY	GREENVILLE, TOWN OF	05/16/2008 (M)
GREENE COUNTY	HALCOTT, TOWN OF	05/16/2008 (M)
GREENE COUNTY	HUNTER, TOWN OF	05/16/2008
GREENE COUNTY	HUNTER, VILLAGE OF	05/16/2008
GREENE COUNTY	JEWETT, TOWN OF	05/16/2008
GREENE COUNTY	LEXINGTON, TOWN OF	05/16/2008
GREENE COUNTY	NEW BALTIMORE, TOWN OF	05/16/2008 (M)
GREENE COUNTY	PRATTSVILLE, TOWN OF	05/16/2008
GREENE COUNTY	TANNERSVILLE, VILLAGE OF	05/16/2008
GREENE COUNTY	WINDHAM, TOWN OF	05/16/2008
HAMILTON COUNTY	ARIETTA, TOWN OF	(NSFHA)
HAMILTON COUNTY	BENSON, TOWN OF	(NSFHA)
HAMILTON COUNTY	HOPE, TOWN OF	04/30/86(M)
HAMILTON COUNTY	INDIAN LAKE, TOWN OF	12/04/85(M)
HAMILTON COUNTY	INLET, TOWN OF	(NSFHA)
HAMILTON COUNTY	LAKE PLEASANT, TOWN OF	(NSFHA)
HAMILTON COUNTY	LONG LAKE, TOWN OF	09/24/1984 (M)
HAMILTON COUNTY	MOREHOUSE, TOWN OF	(NSFHA)
HAMILTON COUNTY	SPECULATOR, VILLAGE OF	02/06/1984 (M)
HAMILTON COUNTY	WELLS, TOWN OF	06/03/1986 (M)
HERKIMER COUNTY	COLD BROOK, VILLAGE OF	12/20/2000
HERKIMER COUNTY	COLUMBIA, TOWN OF	07/16/1982 (M)
HERKIMER COUNTY	DANUBE, TOWN OF	05/12/1999 (M)
HERKIMER COUNTY	DOLGEVILLE, VILLAGE OF	03/16/1983
HERKIMER COUNTY	FAIRFIELD, TOWN OF	10/18/1988
HERKIMER COUNTY	FRANKFORT, TOWN OF	12/20/2000
HERKIMER COUNTY	FRANKFORT, VILLAGE OF	03/07/2001
HERKIMER COUNTY	GERMAN FLATTS, TOWN OF	05/15/1985 (M)
HERKIMER COUNTY	HERKIMER, TOWN OF	04/17/1985 (M)
HERKIMER COUNTY	HERKIMER, VILLAGE OF	06/17/2002
HERKIMER COUNTY	ILION, VILLAGE OF	09/08/1999
HERKIMER COUNTY	LITCHFIELD, TOWN OF	05/07/2001

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
HERKIMER COUNTY	LITTLE FALLS, CITY OF	04/04/1983
HERKIMER COUNTY	LITTLE FALLS, TOWN OF	03/28/1980 (M)
HERKIMER COUNTY	MANHEIM, TOWN OF	05/01/1985 (M)
HERKIMER COUNTY	MIDDLEVILLE, VILLAGE OF	07/03/1985 (M)
HERKIMER COUNTY	MOHAWK, VILLAGE OF	09/08/1999
HERKIMER COUNTY	NEWPORT, TOWN OF	06/02/1999
HERKIMER COUNTY	NEWPORT, VILLAGE OF	04/02/1991
HERKIMER COUNTY	NORWAY, TOWN OF	07/03/1985 (M)
HERKIMER COUNTY	OHIO, TOWN OF	09/24/1984 (M)
HERKIMER COUNTY	POLAND, VILLAGE OF	06/02/1999 (M)
HERKIMER COUNTY	RUSSIA, TOWN OF	06/02/1999
HERKIMER COUNTY	SALISBURY, TOWN OF	07/03/1985 (M)
HERKIMER COUNTY	SCHUYLER, TOWN OF	06/20/2001
HERKIMER COUNTY	STARK, TOWN OF	05/15/1985 (M)
HERKIMER COUNTY	WARREN, TOWN OF	(NSFHA)
HERKIMER COUNTY	WEBB, TOWN OF	07/30/1982 (M)
HERKIMER COUNTY	WEST WINFIELD, VILLAGE OF	07/30/1982 (M)
HERKIMER COUNTY	WINFIELD, TOWN OF	07/30/1982 (M)
JEFFERSON COUNTY	ADAMS, TOWN OF	06/05/1985 (M)
JEFFERSON COUNTY	ADAMS, VILLAGE OF	06/19/1985 (M)
JEFFERSON COUNTY	ALEXANDRIA BAY, VILLAGE OF	04/03/1978
JEFFERSON COUNTY	ALEXANDRIA, TOWN OF	10/15/1985 (M)
JEFFERSON COUNTY	ANTWERP, TOWN OF	04/15/1986 (M)
JEFFERSON COUNTY	ANTWERP, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	BLACK RIVER, VILLAGE OF	06/05/1989 (M)
JEFFERSON COUNTY	BROWNVILLE, TOWN OF	06/02/1992
JEFFERSON COUNTY	BROWNVILLE, VILLAGE OF	03/18/1986 (M)
JEFFERSON COUNTY	CAPE VINCENT, TOWN OF	06/02/1992
JEFFERSON COUNTY	CAPE VINCENT, VILLAGE OF	04/17/1985 (M)
JEFFERSON COUNTY	CARTHAGE, VILLAGE OF	06/17/1991
JEFFERSON COUNTY	CHAMPION, TOWN OF	06/02/1993
JEFFERSON COUNTY	CHAUMONT, VILLAGE OF	09/08/1999
JEFFERSON COUNTY	CLAYTON, TOWN OF	04/02/1986
JEFFERSON COUNTY	CLAYTON, VILLAGE OF	12/1/1977
JEFFERSON COUNTY	DEFERIET, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	DEXTER, VILLAGE OF	06/15/1994
JEFFERSON COUNTY	ELLISBURG, TOWN OF	05/18/1992
JEFFERSON COUNTY	ELLISBURG, VILLAGE OF	06/19/1985 (M)
JEFFERSON COUNTY	EVANS MILLS, VILLAGE OF	01/02/1992
JEFFERSON COUNTY	GLEN PARK, VILLAGE OF	(NSFHA)
JEFFERSON COUNTY	HENDERSON, TOWN OF	05/18/1992
JEFFERSON COUNTY	HERRINGS, VILLAGE OF	12/18/1985
JEFFERSON COUNTY	HOUNSFIELD, TOWN OF	05/18/1992
JEFFERSON COUNTY	LERAY, TOWN OF	02/02/1902
JEFFERSON COUNTY	LYME, TOWN OF	09/02/1993
JEFFERSON COUNTY	ORLEANS, TOWN OF	03/01/1978
JEFFERSON COUNTY	PAMELIA, TOWN OF	01/02/1992
JEFFERSON COUNTY	PHILADELPHIA, TOWN OF	06/05/89(M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
JEFFERSON COUNTY	PHILADELPHIA, VILLAGE OF	09/15/1993
JEFFERSON COUNTY	RODMAN, TOWN OF	07/03/1985 (M)
JEFFERSON COUNTY	RUTLAND, TOWN OF	08/18/1992
JEFFERSON COUNTY	SACKETS HARBOR, VILLAGE OF	05/02/1994
JEFFERSON COUNTY	THERESA, TOWN OF	10/15/1985 (M)
JEFFERSON COUNTY	THERESA, VILLAGE OF	10/15/1985 (M)
JEFFERSON COUNTY	WATERTOWN, CITY OF	08/02/1993
JEFFERSON COUNTY	WATERTOWN, TOWN OF	08/02/1993
JEFFERSON COUNTY	WEST CARTHAGE, VILLAGE OF	09/28/1990
JEFFERSON COUNTY	WILNA, TOWN OF	01/16/1992
JEFFERSON COUNTY	WORTH, TOWN OF	(NSFHA)
LEWIS COUNTY	CASTORLAND, VILLAGE OF	(NSFHA)
LEWIS COUNTY	CONSTABLEVILLE, VILLAGE OF	07/16/1982 (M)
LEWIS COUNTY	COPENHAGEN, VILLAGE OF	(NSFHA)
LEWIS COUNTY	CROGHAM, VILLAGE OF	05/15/1985 (M)
LEWIS COUNTY	CROGHAN, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	DENMARK, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	DIANA, TOWN OF	09/24/1984 (M)
LEWIS COUNTY	GREIG, TOWN OF	05/15/1985 (M)
LEWIS COUNTY	HARRISBURG, TOWN OF	(NSFHA)
LEWIS COUNTY	HARRISVILLE, VILLAGE OF	09/24/1984 (M)
LEWIS COUNTY	LEWIS, TOWN OF	09/29/1996
LEWIS COUNTY	LEYDEN, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	LOWVILLE, TOWN OF	06/20/2000
LEWIS COUNTY	LOWVILLE, VILLAGE OF	06/20/2000
LEWIS COUNTY	LYONS FALLS, VILLAGE OF	06/19/1985 (M)
LEWIS COUNTY	LYONSDALE, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	MARTINSBURG, TOWN OF	06/19/1985 (M)
LEWIS COUNTY	NEW BREMEN, TOWN OF	05/04/2000
LEWIS COUNTY	OSCEOLA, TOWN OF	06/30/1976 (M)
LEWIS COUNTY	PINCKNEY, TOWN OF	(NSFHA)
LEWIS COUNTY	PORT LEYDEN, VILLAGE OF	06/19/1985 (M)
LEWIS COUNTY	TURIN, TOWN OF	08/02/1994
LEWIS COUNTY	TURIN, VILLAGE OF	07/01/1977 (M)
LEWIS COUNTY	WATSON, TOWN OF	07/19/2000
LEWIS COUNTY	WEST TURIN, TOWN OF	(NSFHA)
LIVINGSTON COUNTY	AVON, TOWN OF	08/15/1978
LIVINGSTON COUNTY	AVON, VILLAGE OF	08/01/1978
LIVINGSTON COUNTY	CALEDONIA, TOWN OF	06/01/1981
LIVINGSTON COUNTY	CALEDONIA, VILLAGE OF	06/01/1981
LIVINGSTON COUNTY	CONESUS, TOWN OF	02/15/1991
LIVINGSTON COUNTY	DANSVILLE, VILLAGE OF	04/05/2010
LIVINGSTON COUNTY	GENESEO, TOWN OF	09/29/1996
LIVINGSTON COUNTY	GENESEO, VILLAGE OF	09/29/1996
LIVINGSTON COUNTY	GROVELAND, TOWN OF	02/15/1991
LIVINGSTON COUNTY	LEICESTER, TOWN OF	01/20/1982
LIVINGSTON COUNTY	LEICESTER, VILLAGE OF	08/27/1982 (M)
LIVINGSTON COUNTY	LIMA, 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
LIVINGSTON COUNTY	LIMA, VILLAGE OF	07/23/1982 (M)
LIVINGSTON COUNTY	LIVONIA, TOWN OF	02/19/1992
LIVINGSTON COUNTY	LIVONIA, VILLAGE OF	06/01/1988 (L)
LIVINGSTON COUNTY	MOUNT MORRIS, TOWN OF	(NSFHA)
LIVINGSTON COUNTY	MOUNT MORRIS, VILLAGE OF	08/01/1978
LIVINGSTON COUNTY	NORTH DANSVILLE, TOWN OF	04/05/2010
LIVINGSTON COUNTY	NUNDA, TOWN OF	07/03/1985 (M)
LIVINGSTON COUNTY	NUNDA, VILLAGE OF	03/23/1984 (M)
LIVINGSTON COUNTY	OSSIAN, TOWN OF	06/08/1984 (M)
LIVINGSTON COUNTY	PORTAGE,TOWN OF	12/18/1984
LIVINGSTON COUNTY	SPARTA, TOWN OF	04/05/2010
LIVINGSTON COUNTY	SPRINGWATER, TOWN OF	08/24/1984 (M)
LIVINGSTON COUNTY	WEST SPARTA, TOWN OF	04/05/2010
LIVINGSTON COUNTY	YORK, TOWN OF	01/20/1982
MADISON COUNTY	BROOKFIELD, TOWN OF	04/17/1985 (M)
MADISON COUNTY	CANASTOTA , VILLAGE OF	04/15/1988
MADISON COUNTY	CAZENOVIA, TOWN OF	06/19/1985
MADISON COUNTY	CAZENOVIA, VILLAGE OF	06/19/1985
MADISON COUNTY	CHITTENANGO, VILLAGE OF	02/01/1985 (M)
MADISON COUNTY	DE RUYTER, TOWN OF	06/08/1984
MADISON COUNTY	DE RUYTER, VILLAGE OF	08/24/1984 (M)
MADISON COUNTY	EATON, TOWN OF	09/10/1984 (M)
MADISON COUNTY	FENNER, TOWNSHIP OF	02/05/1986
MADISON COUNTY	GEORGETOWN, TOWN OF	11/02/1984 (M)
MADISON COUNTY	HAMILTON, TOWN OF	09/27/2002
MADISON COUNTY	HAMILTON,VILLAGE	09/27/2002
MADISON COUNTY	LEBANON, TOWN OF	04/17/1985 (M)
MADISON COUNTY	LENOX, TOWN OF	06/03/1988
MADISON COUNTY	LINCOLN, TOWN OF	09/04/1985 (M)
MADISON COUNTY	MADISON, TOWN OF	01/19/1983
MADISON COUNTY	MORRISVILLE, VILLAGE OF	04/15/1982
MADISON COUNTY	MUNNSVILLE, VILLAGE OF	09/15/1983
MADISON COUNTY	NELSON, TOWN OF	10/05/1984 (M)
MADISON COUNTY	ONEIDA, CITY OF	02/23/2001
MADISON COUNTY	SMITHFIELD, TOWN OF	04/17/1985 (M)
MADISON COUNTY	STOCKBRIDGE, TOWN OF	(NSFHA)
MADISON COUNTY	SULLIVAN, TOWN OF	05/15/1986
MADISON COUNTY	WAMPSVILLE, VILLAGE OF	(NSFHA)
MONROE COUNTY	BRIGHTON, TOWN OF	08/28/2008
MONROE COUNTY	BROCKPORT, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	CHILI, TOWN OF	08/28/2008
MONROE COUNTY	CHURCHVILLE, VILLAGE OF	08/28/2008
MONROE COUNTY	CLARKSON, TOWN OF	08/28/2008
MONROE COUNTY	EAST ROCHESTER, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	FAIRPORT, VILLAGE OF	08/28/2008
MONROE COUNTY	GATES, TOWN OF	08/28/2008
MONROE COUNTY	GREECE, TOWN OF	08/28/2008
MONROE COUNTY	HAMLIN, TOWN OF	08/28/2008

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
MONROE COUNTY	HENRIETTA, TOWN OF	08/28/2008
MONROE COUNTY	HILTON, VILLAGE OF	08/28/2008
MONROE COUNTY	HONEOYE FALLS, VILLAGE OF	08/28/2008
MONROE COUNTY	IRONDEQUOIT, TOWN OF	08/28/2008
MONROE COUNTY	MENDON, TOWN OF	08/28/2008
MONROE COUNTY	OGDEN, TOWN OF	08/28/2008
MONROE COUNTY	PARMA, TOWN OF	08/28/2008
MONROE COUNTY	PENFIELD, TOWN OF	08/28/2008
MONROE COUNTY	PERINTON, TOWN OF	08/28/2008
MONROE COUNTY	PITTSFORD, TOWN OF	08/28/2008
MONROE COUNTY	PITTSFORD, VILLAGE OF	08/28/2008 (M)
MONROE COUNTY	RIGA, TOWN OF	08/28/2008
MONROE COUNTY	ROCHESTER, CITY OF	08/28/2008
MONROE COUNTY	RUSH, TOWN OF	08/28/2008
MONROE COUNTY	SCOTTSVILLE, VILLAGE OF	08/28/2008
MONROE COUNTY	SPENCERPORT, VILLAGE OF	08/28/2008
MONROE COUNTY	SWEDEN, TOWN OF	08/28/2008 (M)
MONROE COUNTY	WEBSTER, TOWN OF	08/28/2008
MONROE COUNTY	WEBSTER, VILLAGE OF	08/28/2008
MONROE COUNTY	WHEATLAND, TOWN OF	08/28/2008
MONTGOMERY COUNTY	AMES, VILLAGE OF	12/4/1985
MONTGOMERY COUNTY	AMSTERDAM, CITY OF	06/19/1985
MONTGOMERY COUNTY	AMSTERDAM, TOWN OF	12/01/1987 (L)
MONTGOMERY COUNTY	CANAJOHARIE, TOWN OF	01/06/1983
MONTGOMERY COUNTY	CANAJOHARIE, VILLAGE OF	11/3/1982
MONTGOMERY COUNTY	CHARLESTON, TOWN OF	10/15/1985 (M)
MONTGOMERY COUNTY	FLORIDA, TOWN OF	12/01/1987 (L)
MONTGOMERY COUNTY	FONDA, VILLAGE OF	07/06/1983
MONTGOMERY COUNTY	FORT JOHNSON, VILLAGE OF	01/19/1983
MONTGOMERY COUNTY	FORT PLAIN, VILLAGE OF	06/17/2002
MONTGOMERY COUNTY	FULTONVILLE, VILLAGE OF	10/15/1982
MONTGOMERY COUNTY	GLEN, TOWN OF	02/19/1986 (M)
MONTGOMERY COUNTY	HAGAMAN, VILLAGE OF	03/18/1986 (M)
MONTGOMERY COUNTY	MINDEN, TOWN OF	01/19/1983
MONTGOMERY COUNTY	MOHAWK, TOWN OF	08/05/1985 (M)
MONTGOMERY COUNTY	NELLISTON, VILLAGE OF	11/3/1982
MONTGOMERY COUNTY	PALATINE BRIDGE, VILLAGE OF	11/17/1982
MONTGOMERY COUNTY	PALATINE, TOWN OF	05/04/1987
MONTGOMERY COUNTY	ROOT, TOWN OF	04/01/1988 (L)
MONTGOMERY COUNTY	ST. JOHNSVILLE, TOWN OF	03/16/1983
MONTGOMERY COUNTY	ST. JOHNSVILLE, VILLAGE OF	09/29/1989
NASSAU COUNTY	ATLANTIC BEACH, VILLAGE OF	09/11/2009
NASSAU COUNTY	BAXTER ESTATES, VILLAGE OF	09/11/2009
NASSAU COUNTY	BAYVILLE, VILLAGE OF	09/11/2009
NASSAU COUNTY	CEDARHURST, VILLAGE OF	09/11/2009
NASSAU COUNTY	CENTRE ISLAND, VILLAGE OF	09/11/2009
NASSAU COUNTY	COVE NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	EAST HILLS, VILLAGE OF	(NSFHA)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
NASSAU COUNTY	EAST ROCKAWAY, VILLAGE OF	09/11/2009
NASSAU COUNTY	EAST WILLISTON, VILLAGE OF	(NSFHA)
NASSAU COUNTY	FLORAL PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	FLOWER HILL, VILLAGE OF	09/11/2009
NASSAU COUNTY	FREEPORT, VILLAGE OF	09/11/2009
NASSAU COUNTY	GARDEN CITY, VILLAGE OF	(NSFHA)
NASSAU COUNTY	GLEN COVE, CITY OF	09/11/2009
NASSAU COUNTY	GREAT NECK ESTATES, VILLAGE OF	09/11/2009
NASSAU COUNTY	GREAT NECK PLAZA, VILLAGE OF	09/11/2009
NASSAU COUNTY	GREAT NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEMPSTEAD, TOWN OF	09/11/2009
NASSAU COUNTY	HEMPSTEAD, VILLAGE OF	(NSFHA)
NASSAU COUNTY	HEWLETT BAY PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEWLETT HARBOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	HEWLETT NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	ISLAND PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	KENSINGTON, VILLAGE OF	09/11/2009
NASSAU COUNTY	KINGS POINT, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAKE SUCCESS, VILLAGE OF	(NSFHA)
NASSAU COUNTY	LATTINGTOWN, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAUREL HOLLOW, VILLAGE OF	09/11/2009
NASSAU COUNTY	LAWRENCE, VILLAGE OF	09/11/2009
NASSAU COUNTY	LONG BEACH, CITY OF	09/11/2009
NASSAU COUNTY	LYNBROOK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MALVERNE, VILLAGE OF	09/11/2009
NASSAU COUNTY	MANORHAVEN, VILLAGE OF	09/11/2009
NASSAU COUNTY	MASSAPEQUA PARK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MILL NECK, VILLAGE OF	09/11/2009
NASSAU COUNTY	MINEOLA, VILLAGE OF	(NSFHA)
NASSAU COUNTY	MUNSEY PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	NEW HYDE PARK, VILLAGE OF	(NSFHA)
NASSAU COUNTY	NORTH HEMPSTEAD, TOWN OF	09/11/2009
NASSAU COUNTY	NORTH HILLS, VILLAGE OF	(NSFHA)
NASSAU COUNTY	OYSTER BAY COVE, VILLAGE OF	09/11/2009
NASSAU COUNTY	OYSTER BAY, TOWN OF	09/11/2009
NASSAU COUNTY	PLANDOME HEIGHTS, VILLAGE OF	09/11/2009
NASSAU COUNTY	PLANDOME MANOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	PLANDOME, VILLAGE OF	09/11/2009
NASSAU COUNTY	PORT WASHINGTON NORTH, VILLAG	09/11/2009
NASSAU COUNTY	ROCKVILLE CENTRE, VILLAGE OF	09/11/2009
NASSAU COUNTY	ROSLYN ESTATES, VILLAGE OF	(NSFHA)
NASSAU COUNTY	ROSLYN HARBOR, VILLAGE OF	09/11/2009
NASSAU COUNTY	ROSLYN, VILLAGE OF	09/11/2009
NASSAU COUNTY	RUSSELL GARDENS, VILLAGE OF	09/11/2009
NASSAU COUNTY	SADDLE ROCK, VILLAGE OF	09/11/2009
NASSAU COUNTY	SANDS POINT, VILLAGE OF	09/11/2009
NASSAU COUNTY	SEA CLIFF, VILLAGE OF	09/11/2009
NASSAU COUNTY	STEWART MANOR, VILLAGE OF	(NSFHA)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
NASSAU COUNTY	THOMASTON, VILLAGE OF	09/11/2009
NASSAU COUNTY	VALLEY STREAM, VILLAGE OF	09/11/2009
NASSAU COUNTY	WESTBURY, VILLAGE OF	(NSFHA)
NASSAU COUNTY	WOODSBURGH, VILLAGE OF	09/11/2009
NIAGARA COUNTY	BARKER, VILLAGE OF	09/17/2010
NIAGARA COUNTY	CAMBRIA, TOWN OF	09/17/2010
NIAGARA COUNTY	HARTLAND, TOWN OF	09/17/2010 (M)
NIAGARA COUNTY	LEWISTON, TOWN OF	09/17/2010
NIAGARA COUNTY	LEWISTON, VILLAGE OF	(NSFHA)
NIAGARA COUNTY	LOCKPORT, CITY OF	09/17/2010
NIAGARA COUNTY	LOCKPORT, TOWN OF	09/17/2010
NIAGARA COUNTY	MIDDLEPORT, VILLAGE OF	09/17/2010
NIAGARA COUNTY	NEWFANE, TOWN OF	09/17/2010
NIAGARA COUNTY	NIAGARA FALLS, CITY OF	09/17/2010
NIAGARA COUNTY	NIAGARA, TOWN OF	09/17/2010
NIAGARA COUNTY	NORTH TONAWANDA, CITY OF	09/17/2010
NIAGARA COUNTY	PENDLETON, TOWN OF	09/17/2010
NIAGARA COUNTY	PORTER, TOWN OF	09/17/2010
NIAGARA COUNTY	ROYALTON, TOWN OF	09/17/2010
NIAGARA COUNTY	SOMERSET, TOWN OF	09/17/2010
NIAGARA COUNTY	WHEATFIELD, TOWN OF	09/17/2010
NIAGARA COUNTY	WILSON, TOWN OF	09/17/2010
NIAGARA COUNTY	WILSON, VILLAGE OF	09/17/2010
NIAGARA COUNTY	YOUNGSTOWN, VILLAGE OF	09/17/2010
ONEIDA COUNTY	ANNSVILLE, TOWN OF	04/05/1988
ONEIDA COUNTY	AUGUSTA, TOWN OF	05/01/1985 (M)
ONEIDA COUNTY	AVA, TOWN OF	02/01/1985 (M)
ONEIDA COUNTY	BARNEVELD, VILLAGE OF	03/23/1999
ONEIDA COUNTY	BOONVILLE, TOWN OF	07/03/1985 (M)
ONEIDA COUNTY	BOONVILLE, VILLAGE OF	04/17/1985 (M)
ONEIDA COUNTY	BRIDGEWATER, TOWN OF	(NSFHA)
ONEIDA COUNTY	BRIDGEWATER, VILLAGE OF	04/15/1982
ONEIDA COUNTY	CAMDEN, TOWN OF	09/07/1998
ONEIDA COUNTY	CAMDEN, VILLAGE OF	08/16/1988
ONEIDA COUNTY	CLAYVILLE, VILLAGE OF	07/05/1983
ONEIDA COUNTY	CLINTON, VILLAGE OF	05/01/1985
ONEIDA COUNTY	DEERFIELD, TOWN OF	06/02/1999
ONEIDA COUNTY	FLORENCE, TOWN OF	04/17/1985 (M)
ONEIDA COUNTY	FLOYD, TOWN OF	03/15/1984
ONEIDA COUNTY	FORESTPORT, TOWN OF	04/17/1985 (M)
ONEIDA COUNTY	HOLLAND PATENT, VILLAGE OF	05/21/2001
ONEIDA COUNTY	KIRKLAND, TOWN OF	04/03/1985
ONEIDA COUNTY	LEE, TOWN OF	08/03/1998
ONEIDA COUNTY	MARCY, TOWN OF	06/01/1984
ONEIDA COUNTY	MARSHALL, TOWN OF	09/30/1982
ONEIDA COUNTY	NEW HARTFORD, TOWN OF	04/18/1983
ONEIDA COUNTY	NEW HARTFORD, VILLAGE OF	07/05/1983
ONEIDA COUNTY	NEW YORK MILLS, VILLAGE OF	05/04/2000

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ONEIDA COUNTY	ONEIDA CASTLE, VILLAGE OF	07/04/1989
ONEIDA COUNTY	ORISKANY FALLS, VILLAGE OF	01/19/1983
ONEIDA COUNTY	ORISKANY, VILLAGE OF	09/15/1983
ONEIDA COUNTY	PARIS, TOWN OF	09/15/1983
ONEIDA COUNTY	PROSPECT, VILLAGE OF	11/20/2000
ONEIDA COUNTY	REMSEN, TOWN OF	05/01/1985 (M)
ONEIDA COUNTY	REMSEN, VILLAGE OF	09/24/1984 (M)
ONEIDA COUNTY	ROME, CITY OF	09/21/1998
ONEIDA COUNTY	SANGERFIELD, TOWN OF	06/05/1985
ONEIDA COUNTY	SHERRILL, CITY OF	09/15/1983
ONEIDA COUNTY	STEUBEN, TOWN OF	09/24/1984 (M)
ONEIDA COUNTY	SYLVAN BEACH, VILLAGE OF	06/02/1999
ONEIDA COUNTY	TRENTON, TOWN OF	09/07/1998
ONEIDA COUNTY	UTICA, CITY OF	02/01/1984
ONEIDA COUNTY	VERNON, TOWN OF	08/16/1988
ONEIDA COUNTY	VERNON, VILLAGE OF	04/15/1988
ONEIDA COUNTY	VERONA, TOWN OF	10/20/1999
ONEIDA COUNTY	VIENNA, TOWN OF	10/20/1999
ONEIDA COUNTY	WATERVILLE, VILLAGE OF	08/02/1982
ONEIDA COUNTY	WESTERN, TOWN OF	05/04/1989
ONEIDA COUNTY	WESTMORELAND, TOWN OF	03/02/1983
ONEIDA COUNTY	WHITESBORO, VILLAGE OF	05/04/2000
ONEIDA COUNTY	WHITESTOWN, TOWN OF	05/04/2000
ONEIDA COUNTY	YORKVILLE, VILLAGE OF	05/04/2000
ONONDAGA COUNTY	BALDWINSVILLE, VILLAGE OF	03/01/1984
ONONDAGA COUNTY	CAMILLUS, TOWN OF	05/18/1999
ONONDAGA COUNTY	CAMILLUS, VILLAGE OF	05/18/1999
ONONDAGA COUNTY	CICERO, TOWN OF	09/15/1994
ONONDAGA COUNTY	CLAY, TOWN OF	03/16/1992
ONONDAGA COUNTY	DEWITT, TOWN OF	03/01/1979
ONONDAGA COUNTY	EAST SYRACUSE, VILLAGE OF	08/03/1981
ONONDAGA COUNTY	ELBRIDGE, TOWN OF	08/16/1982
ONONDAGA COUNTY	ELBRIDGE, VILLAGE OF	08/16/1982
ONONDAGA COUNTY	FABIUS, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	FAYETTEVILLE, VILLAGE OF	04/17/1985
ONONDAGA COUNTY	GEDDES, TOWN OF	02/17/1982
ONONDAGA COUNTY	JORDAN, VILLAGE OF	08/16/1982
ONONDAGA COUNTY	LAFAYETTE, TOWN OF	04/03/1985
ONONDAGA COUNTY	LIVERPOOL, VILLAGE OF	02/04/1981
ONONDAGA COUNTY	LYSANDER, TOWN OF	02/04/1983
ONONDAGA COUNTY	MANLIUS, TOWN OF	09/17/1992
ONONDAGA COUNTY	MANLIUS, VILLAGE OF	08/01/1984
ONONDAGA COUNTY	MARCELLUS, TOWN OF	08/16/1982
ONONDAGA COUNTY	MARCELLUS, VILLAGE OF	06/01/1982
ONONDAGA COUNTY	MINOA, VILLAGE OF	09/02/1982
ONONDAGA COUNTY	NORTH SYRACUSE, VILLAGE OF	(NSFHA)
ONONDAGA COUNTY	ONONDAGA, TOWN OF	06/17/1991
ONONDAGA COUNTY	OTISCO, TOWN OF	06/03/1986 (M)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ONONDAGA COUNTY	POMPEY, TOWN OF	10/8/1982
ONONDAGA COUNTY	SALINA, TOWN OF	08/16/1982
ONONDAGA COUNTY	SKANEATELES, TOWN OF	06/01/1982
ONONDAGA COUNTY	SKANEATELES, VILLAGE OF	02/17/1982
ONONDAGA COUNTY	SOLVAY, VILLAGE OF	(NSFHA)
ONONDAGA COUNTY	SPAFFORD, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	SYRACUSE, CITY OF	05/15/1986
ONONDAGA COUNTY	TULLY, TOWN OF	04/30/1986 (M)
ONONDAGA COUNTY	TULLY, VILLAGE OF	01/19/1983
ONONDAGA COUNTY	VAN BUREN, TOWN OF	03/01/1984
ONTARIO COUNTY	BLOOMFIELD, VILLAGE OF	8/15/1983
ONTARIO COUNTY	BRISTOL, TOWN OF	01/20/1984 (M)
ONTARIO COUNTY	CANADICE, TOWN OF	05/15/1984
ONTARIO COUNTY	CANANDAIGUA, CITY OF	09/24/1982
ONTARIO COUNTY	CANANDAIGUA, TOWN OF	03/03/1997
ONTARIO COUNTY	CLIFTON SPRINGS, VILLAGE OF	07/23/1982 (M)
ONTARIO COUNTY	EAST BLOOMFIELD, TOWN OF	08/15/1983
ONTARIO COUNTY	FARMINGTON, TOWN OF	09/30/1983
ONTARIO COUNTY	GENEVA, CITY OF	04/15/1982
ONTARIO COUNTY	GENEVA, TOWN OF	02/15/1978
ONTARIO COUNTY	GORHAM, TOWN OF	12/5/1996
ONTARIO COUNTY	HOPEWELL, TOWN OF	02/27/1984 (M)
ONTARIO COUNTY	MANCHESTER, TOWN OF	03/09/1984 (M)
ONTARIO COUNTY	MANCHESTER, VILLAGE OF	01/20/1984 (M)
ONTARIO COUNTY	NAPLES, TOWN OF	06/08/1984 (M)
ONTARIO COUNTY	NAPLES, VILLAGE OF	09/30/1977
ONTARIO COUNTY	PHELPS, TOWN OF	12/03/1982 (M)
ONTARIO COUNTY	PHELPS, VILLAGE OF	01/20/1984 (M)
ONTARIO COUNTY	RICHMOND, TOWN OF	12/18/1984
ONTARIO COUNTY	SENECA, TOWN OF	06/22/1984(M)
ONTARIO COUNTY	SHORTSVILLE, VILLAGE OF	09/24/1984 (M)
ONTARIO COUNTY	SOUTH BRISTOL, TOWN OF	05/18/1998
ONTARIO COUNTY	VICTOR, TOWN OF	09/30/1983
ONTARIO COUNTY	VICTOR, VILLAGE OF	05/17/2004
ONTARIO COUNTY	WEST BLOOMFIELD, TOWN OF	06/01/1978
ORANGE COUNTY	BLOOMING GROVE, TOWN OF	08/03/2009
ORANGE COUNTY	CHESTER, TOWN OF	08/03/2009
ORANGE COUNTY	CHESTER, VILLAGE OF	08/03/2009
ORANGE COUNTY	CORNWALL ON THE HUDSON, VILLA	08/03/2009
ORANGE COUNTY	CORNWALL, TOWN OF	08/03/2009
ORANGE COUNTY	CRAWFORD, TOWN OF	08/03/2009
ORANGE COUNTY	DEER PARK, TOWN OF	08/03/2009
ORANGE COUNTY	FLORIDA, VILLAGE OF	08/03/2009
ORANGE COUNTY	GOSHEN, TOWN OF	08/03/2009
ORANGE COUNTY	GOSHEN, VILLAGE OF	08/03/2009
ORANGE COUNTY	GREENVILLE, TOWN OF	08/03/2009
ORANGE COUNTY	GREENWOOD LAKE, VILLAGE OF	08/03/2009
ORANGE COUNTY	HAMPTONBURGH, TOWN OF	08/03/2009

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ORANGE COUNTY	HARRIMAN, VILLAGE OF	08/03/2009
ORANGE COUNTY	HIGHLAND FALLS, VILLAGE OF	08/03/2009
ORANGE COUNTY	HIGHLANDS, TOWNSHIP OF	08/03/2009
ORANGE COUNTY	KIRYAS JOEL, VILLAGE OF	08/03/2009
ORANGE COUNTY	MAYBROOK, VILLAGE OF	08/03/2009 (M)
ORANGE COUNTY	MIDDLETOWN, CITY OF	08/03/2009
ORANGE COUNTY	MINISINK, TOWN OF	08/03/2009
ORANGE COUNTY	MONROE, TOWN OF	08/03/2009
ORANGE COUNTY	MONROE, VILLAGE OF	08/03/2009
ORANGE COUNTY	MONTGOMERY, TOWN OF	08/03/2009
ORANGE COUNTY	MONTGOMERY, VILLAGE OF	08/03/2009
ORANGE COUNTY	MOUNT HOPE, TOWN OF	08/03/2009 (M)
ORANGE COUNTY	NEW WINDSOR, TOWN OF	08/03/2009
ORANGE COUNTY	NEWBURGH, CITY OF	08/03/2009
ORANGE COUNTY	NEWBURGH, TOWN OF	08/03/2009
ORANGE COUNTY	PORT JERVIS, CITY OF	08/03/2009
ORANGE COUNTY	SOUTH BLOOMING GROVE, VILLAGE	08/03/2009
ORANGE COUNTY	TUXEDO PARK, VILLAGE OF	08/03/2009
ORANGE COUNTY	TUXEDO, TOWN OF	08/03/2009
ORANGE COUNTY	UNIONVILLE, VILLAGE OF	08/03/2009 (M)
ORANGE COUNTY	WALDEN, VILLAGE OF	08/03/2009
ORANGE COUNTY	WALLKILL, TOWN OF	08/03/2009
ORANGE COUNTY	WARWICK, TOWN OF	08/03/2009
ORANGE COUNTY	WARWICK, VILLAGE OF	08/03/2009
ORANGE COUNTY	WASHINGTONVILLE, VILLAGE OF	08/03/2009
ORANGE COUNTY	WAWAYANDA, TOWN OF	08/03/2009
ORANGE COUNTY	WOODBURY, VILLAGE OF	08/03/2009
ORLEANS COUNTY	ALBION, TOWN OF	08/08/1980 (M)
ORLEANS COUNTY	ALBION, VILLAGE OF	11/30/1979 (M)
ORLEANS COUNTY	BARRE, TOWN OF	10/15/1981 (M)
ORLEANS COUNTY	CARLTON, TOWN OF	11/1/1978
ORLEANS COUNTY	CLARENDON,TOWN OF	(NSFHA)
ORLEANS COUNTY	GAINES, TOWN OF	06/08/1984 (M)
ORLEANS COUNTY	HOLLEY, VILLAGE OF	11/30/1979 (M)
ORLEANS COUNTY	KENDALL, TOWN OF	05/01/1978
ORLEANS COUNTY	LYNDONVILLE, VILLAGE OF	09/16/1981
ORLEANS COUNTY	MEDINA, VILLAGE OF	03/28/1980 (M)
ORLEANS COUNTY	MURRAY, TOWN OF	03/21/1980 (M)
ORLEANS COUNTY	RIDGEWAY,TOWN OF	09/14/1979 (M)
ORLEANS COUNTY	SHELBY,TOWN OF	12/23/1983 (M)
ORLEANS COUNTY	YATES, TOWN OF	09/29/1978
OSWEGO COUNTY	ALBION, TOWN OF	04/15/1986 (M)
OSWEGO COUNTY	ALTMAR, VILLAGE OF	02/05/1986 (M)
OSWEGO COUNTY	AMBOY, TOWN OF	03/01/1988 (L)
OSWEGO COUNTY	BOYLSTON, TOWN OF	(NSFHA)
OSWEGO COUNTY	CENTRAL SQUARE,VILLAGE OF	(NSFHA)
OSWEGO COUNTY	CLEVELAND, VILLAGE OF	06/01/1982
OSWEGO COUNTY	CONSTANTIA, TOWN OF	11/3/1982

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
OSWEGO COUNTY	FULTON, CITY OF	04/15/1982
OSWEGO COUNTY	GRANBY, TOWN OF	09/16/1982
OSWEGO COUNTY	HANNIBAL, TOWN OF	02/01/1988 (L)
OSWEGO COUNTY	HANNIBAL, VILLAGE OF	04/01/1987 (L)
OSWEGO COUNTY	HASTINGS, TOWN OF	01/19/1983
OSWEGO COUNTY	LACONA, VILLAGE OF	05/11/1979 (M)
OSWEGO COUNTY	MEXICO, TOWN OF	10/15/1981
OSWEGO COUNTY	MEXICO, VILLAGE OF	10/15/1981
OSWEGO COUNTY	MINETTO, TOWN OF	09/30/1981
OSWEGO COUNTY	NEW HAVEN, TOWN OF	11/2/1995
OSWEGO COUNTY	ORWELL, TOWN OF	02/19/1986
OSWEGO COUNTY	OSWEGO, CITY OF	11/22/1999
OSWEGO COUNTY	OSWEGO, TOWN OF	06/20/2001
OSWEGO COUNTY	PALERMO, TOWN OF	03/01/1988
OSWEGO COUNTY	PARISH, TOWN OF	04/15/1986 (M)
OSWEGO COUNTY	PARISH, VILLAGE OF	02/19/1986 (M)
OSWEGO COUNTY	PHOENIX, VILLAGE OF	02/17/1982
OSWEGO COUNTY	PULASKI, VILLAGE OF	09/02/1982
OSWEGO COUNTY	REDFIELD, TOWN OF	04/01/1991 (L)
OSWEGO COUNTY	RICHLAND, TOWN OF	07/17/1995
OSWEGO COUNTY	SANDY CREEK, TOWN OF	07/17/1995
OSWEGO COUNTY	SANDY CREEK, VILLAGE OF	05/11/1979 (M)
OSWEGO COUNTY	SCHROEPPEL, TOWN OF	08/02/1982
OSWEGO COUNTY	SCRIBA, TOWN OF	06/06/2001
OSWEGO COUNTY	VOLNEY, TOWN OF	04/15/1982
OSWEGO COUNTY	WEST MONROE, TOWN OF	01/20/1982
OSWEGO COUNTY	WILLIAMSTOWN, TOWN OF	03/01/1988
OTSEGO COUNTY	BURLINGTON, TOWN OF	10/21/1983 (M)
OTSEGO COUNTY	BUTTERNUTS, TOWN OF	12/23/1983 (M)
OTSEGO COUNTY	CHERRY VALLEY, TOWN OF	02/01/1988 (L)
OTSEGO COUNTY	CHERRY VALLEY, VILLAGE OF	01/03/1986 (M)
OTSEGO COUNTY	COOPERSTOWN, VILLAGE OF	05/04/2000
OTSEGO COUNTY	DECATUR, TOWN OF	06/18/1987
OTSEGO COUNTY	EDMESTON, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	EXETER, TOWN OF	11/18/1983 (M)
OTSEGO COUNTY	GILBERTSVILLE, VILLAGE OF	11/01/1985 (M)
OTSEGO COUNTY	HARTWICK, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	LAURENS, TOWN OF	05/15/1985 (M)
OTSEGO COUNTY	LAURENS, VILLAGE OF	04/17/1987 (M)
OTSEGO COUNTY	MARYLAND, TOWN OF	06/03/1986 (M)
OTSEGO COUNTY	MIDDLEFIELD, TOWN OF	06/01/1988 (L)
OTSEGO COUNTY	MILFORD, TOWN OF	05/19/1987 (M)
OTSEGO COUNTY	MILFORD, VILLAGE OF	11/18/1983
OTSEGO COUNTY	MORRIS, TOWN OF	01/03/1986 (M)
OTSEGO COUNTY	MORRIS, VILLAGE OF	12/04/1985 (M)
OTSEGO COUNTY	NEW LISBON, TOWN OF	11/18/1983 (M)
OTSEGO COUNTY	ONEONTA, CITY OF	09/29/1978
OTSEGO COUNTY	ONEONTA, TOWN OF	10/17/1986

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
OTSEGO COUNTY	OTEGO, TOWN OF	02/04/1987
OTSEGO COUNTY	OTEGO, VILLAGE OF	11/5/1986
OTSEGO COUNTY	OTSEGO, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	PITTSFIELD, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	PLAINFIELD, TOWN OF	11/04/1983 (M)
OTSEGO COUNTY	RICHFIELD SPRINGS, VILLAGE OF	01/03/1986 (M)
OTSEGO COUNTY	RICHFIELD, TOWN OF	04/15/1986 (M)
OTSEGO COUNTY	ROSEBOOM, TOWN OF	06/01/1988
OTSEGO COUNTY	SPRINGFIELD, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	UNADILLA, TOWN OF	09/30/1987
OTSEGO COUNTY	UNADILLA, VILLAGE OF	09/30/1987
OTSEGO COUNTY	WESTFORD, TOWN OF	06/01/1987 (L)
OTSEGO COUNTY	WORCESTER, TOWN OF	06/01/1987 (L)
PUTNAM COUNTY	BREWSTER, VILLAGE OF	09/18/1986
PUTNAM COUNTY	CARMEL,TOWN OF	10/19/2001
PUTNAM COUNTY	COLD SPRING, VILLAGE OF	03/15/1984
PUTNAM COUNTY	KENT, TOWN OF	09/04/1986
PUTNAM COUNTY	NELSONVILLE, VILLAGE OF	09/10/1984 (M)
PUTNAM COUNTY	PATTERSON, TOWN OF	07/03/1986
PUTNAM COUNTY	PHILIPSTOWN,TOWN OF	06/18/1987
PUTNAM COUNTY	PUTNAM VALLEY, TOWN OF	06/20/2001
PUTNAM COUNTY	SOUTHEAST, TOWN OF	09/04/1986
RENSSELAER COUNTY	BERLIN, TOWN OF	08/17/1979 (M)
RENSSELAER COUNTY	BRUNSWICK, TOWN OF	12/6/2000
RENSSELAER COUNTY	CASTLETON-ON-HUDSON, VILLAGE O	11/15/1984
RENSSELAER COUNTY	EAST GREENBUSH, TOWN OF	03/18/1980
RENSSELAER COUNTY	EAST NASSAU, VILLAGE OF	09/05/1984
RENSSELAER COUNTY	GRAFTON, TOWN OF	10/13/1978 (M)
RENSSELAER COUNTY	HOOSICK FALLS, VILLAGE OF	02/04/2005
RENSSELAER COUNTY	HOOSICK, TOWN OF	08/01/1987 (L)
RENSSELAER COUNTY	NASSAU, TOWN OF	09/05/1984
RENSSELAER COUNTY	NASSAU, VILLAGE OF	05/18/1979 (M)
RENSSELAER COUNTY	NORTH GREENBUSH,TOWN OF	06/18/1980
RENSSELAER COUNTY	PETERSBURG, TOWN OF	09/01/1978 (M)
RENSSELAER COUNTY	PITTSTOWN, TOWN OF	09/05/1990
RENSSELAER COUNTY	POESTENKILL, TOWN OF	09/02/1981
RENSSELAER COUNTY	RENSSELAER, CITY OF	03/18/1980
RENSSELAER COUNTY	SAND LAKE, TOWN OF	05/15/1980
RENSSELAER COUNTY	SCHAGHTICOKE, TOWN OF	07/16/1984
RENSSELAER COUNTY	SCHAGHTICOKE, VILLAGE OF	06/05/1985
RENSSELAER COUNTY	SCHODACK, TOWN OF	08/15/1984
RENSSELAER COUNTY	STEPHENTOWN, TOWN OF	08/03/1981
RENSSELAER COUNTY	TROY, CITY OF	03/18/1980
RENSSELAER COUNTY	VALLEY FALLS, VILLAGE OF	06/05/1985
RICHMOND COUNTY/QUEENS COUNTY/NEW YORK COUNTY/KINGS COUNTY/BRONX COUNTY	NEW YORK, CITY OF	09/05/2007
ROCKLAND COUNTY	CHESTNUT RIDGE, VILLAGE OF	09/16/1988

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ROCKLAND COUNTY	CLARKSTOWN, TOWN OF	05/21/2001
ROCKLAND COUNTY	GRAND VIEW-ON-HUDSON, VILLAGE	10/15/1981
ROCKLAND COUNTY	HAVERSTRAW, TOWN OF	01/06/1982
ROCKLAND COUNTY	HAVERSTRAW, VILLAGE OF	09/02/1981
ROCKLAND COUNTY	HILLBURN, VILLAGE OF	09/20/1996
ROCKLAND COUNTY	KASER, VILLAGE OF	01/01/2050
ROCKLAND COUNTY	MONTEBELLO, VILLAGE OF	01/18/1989
ROCKLAND COUNTY	NEW HEMPSTEAD, VILLAGE OF	12/16/1988
ROCKLAND COUNTY	NEW SQUARE, VILLAGE OF	(NSFHA)
ROCKLAND COUNTY	NYACK, VILLAGE OF	12/4/1985
ROCKLAND COUNTY	ORANGETOWN, TOWN OF	08/02/1982
ROCKLAND COUNTY	PIERMONT, VILLAGE OF	11/17/1982
ROCKLAND COUNTY	POMONA, VILLAGE OF	04/15/1982
ROCKLAND COUNTY	RAMAPO, TOWN OF	02/02/1989
ROCKLAND COUNTY	SLOATSBURG, VILLAGE OF	01/06/1982
ROCKLAND COUNTY	SOUTH NYACK, VILLAGE OF	11/4/1981
ROCKLAND COUNTY	SPRING VALLEY, VILLAGE OF	08/16/1988
ROCKLAND COUNTY	STONY POINT, TOWN OF	09/30/1981
ROCKLAND COUNTY	SUFFERN, VILLAGE OF	03/28/1980
ROCKLAND COUNTY	UPPER NYACK, VILLAGE OF	(NSFHA)
ROCKLAND COUNTY	WESLEY HILLS, VILLAGE OF	09/16/1988
ROCKLAND COUNTY	WEST HAVERSTRAW, VILLAGE OF	09/30/1981
SARATOGA COUNTY	BALLSTON SPA, VILLAGE OF	08/16/1995
SARATOGA COUNTY	BALLSTON, TOWN OF	08/16/1995
SARATOGA COUNTY	CHARLTON, TOWN OF	08/16/1995
SARATOGA COUNTY	CLIFTON PARK, TOWN OF	08/16/1995
SARATOGA COUNTY	CORINTH, TOWN OF	08/16/1995
SARATOGA COUNTY	CORINTH, VILLAGE OF	08/16/1995
SARATOGA COUNTY	DAY, TOWN OF	(NSFHA)
SARATOGA COUNTY	GALWAY, TOWN OF	08/16/1995
SARATOGA COUNTY	GREENFIELD, TOWN OF	08/16/1995
SARATOGA COUNTY	HADLEY, TOWN OF	08/16/1995
SARATOGA COUNTY	HALFMOON, TOWN OF	08/16/1995
SARATOGA COUNTY	MALTA, TOWN OF	08/16/1995
SARATOGA COUNTY	MECHANICVILLE, CITY OF	08/16/1995
SARATOGA COUNTY	MILTON, TOWN OF	08/16/1995
SARATOGA COUNTY	MOREAU, TOWN OF	08/16/1995
SARATOGA COUNTY	NORTHUMBERLAND, TOWN OF	08/16/1995
SARATOGA COUNTY	PROVIDENCE, TOWN OF	08/16/1995
SARATOGA COUNTY	ROUND LAKE, VILLAGE OF	08/16/1995
SARATOGA COUNTY	SARATOGA SPRINGS, CITY OF	08/16/1995
SARATOGA COUNTY	SARATOGA, TOWN OF	08/16/1995
SARATOGA COUNTY	SCHUYLERVILLE, VILLAGE OF	08/16/1995
SARATOGA COUNTY	SOUTH GLENS FALLS, VILLAGE OF	08/16/1995
SARATOGA COUNTY	STILLWATER, TOWN OF	08/16/1995
SARATOGA COUNTY	STILLWATER, VILLAGE OF	08/16/1995
SARATOGA COUNTY	VICTORY, VILLAGE OF	08/16/1995
SARATOGA COUNTY	WATERFORD, TOWN OF	08/16/1995

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SARATOGA COUNTY	WATERFORD, VILLAGE OF	08/16/1995
SARATOGA COUNTY	WILTON,TOWN OF	(NSFHA)
SCHENECTADY COUNTY	DELANSON, VILLAGE OF	05/25/1984 (M)
SCHENECTADY COUNTY	DUANESBURG, TOWN OF	02/17/1989
SCHENECTADY COUNTY	GLENVILLE,TOWN OF	05/04/1987
SCHENECTADY COUNTY	NISKAYUNA, TOWN OF	03/01/1978
SCHENECTADY COUNTY	PRINCETOWN, TOWN OF	07/01/1988 (L)
SCHENECTADY COUNTY	ROTTERDAM, TOWN OF	06/15/1984
SCHENECTADY COUNTY	SCHENECTADY, CITY OF	09/30/1983
SCHENECTADY COUNTY	SCOTIA, VILLAGE OF	06/01/1984
SCHOHARIE COUNTY	BLENHEIM, TOWN OF	04/02/2004
SCHOHARIE COUNTY	BROOME, TOWN OF	04/02/2004
SCHOHARIE COUNTY	CARLISLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	COBLESKILL, TOWN OF	04/02/2004
SCHOHARIE COUNTY	COBLESKILL, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	CONESVILLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	ESPERANCE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	ESPERANCE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	FULTON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	GILBOA, TOWN OF	04/02/2004
SCHOHARIE COUNTY	JEFFERSON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	MIDDLEBURGH, TOWN OF	04/02/2004
SCHOHARIE COUNTY	MIDDLEBURGH, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	RICHMONDVILLE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	RICHMONDVILLE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	SCHOHARIE, TOWN OF	04/02/2004
SCHOHARIE COUNTY	SCHOHARIE, VILLAGE OF	04/02/2004
SCHOHARIE COUNTY	SEWARD, TOWN OF	04/02/2004
SCHOHARIE COUNTY	SHARON SPRING, VILLAGE OF	04/02/2004 (M)
SCHOHARIE COUNTY	SHARON, TOWN OF	04/02/2004
SCHOHARIE COUNTY	SUMMIT, TOWN OF	04/02/2004
SCHOHARIE COUNTY	WRIGHT, TOWN OF	04/02/2004
SCHUYLER COUNTY	BURDETT, VILLAGE OF	06/01/1988 (L)
SCHUYLER COUNTY	CATHARINE, TOWN OF	04/20/1984 (M)
SCHUYLER COUNTY	CAYUTA, TOWN OF	09/24/1984 (M)
SCHUYLER COUNTY	DIX, TOWN OF	10/29/1982 (M)
SCHUYLER COUNTY	HECTOR, TOWN OF	07/20/1984 (M)
SCHUYLER COUNTY	MONTOUR FALLS, VILLAGE OF	09/15/1983
SCHUYLER COUNTY	MONTOUR, TOWN OF	03/01/1988 (L)
SCHUYLER COUNTY	ODESSA, VILLAGE OF	04/20/1984 (M)
SCHUYLER COUNTY	ORANGE, TOWN OF	04/20/1984 (M)
SCHUYLER COUNTY	READING, TOWN OF	(NSFHA)
SCHUYLER COUNTY	TYRONE, TOWN OF	07/06/1984 (M)
SCHUYLER COUNTY	WATKINS GLEN, VILLAGE OF	07/17/1978
SENECA COUNTY	COVERT, TOWN OF	06/08/1984 (M)
SENECA COUNTY	FAYETTE, TOWN OF	01/15/1988
SENECA COUNTY	LODI, TOWN OF	01/15/1988
SENECA COUNTY	LODI, VILLAGE OF	(NSFHA)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SENECA COUNTY	OVID, TOWN OF	01/15/1988
SENECA COUNTY	ROMULUS, TOWN OF	06/05/1985 (M)
SENECA COUNTY	SENECA FALLS, TOWN OF	08/03/1981
SENECA COUNTY	SENECA FALLS, VILLAGE OF	08/03/1981
SENECA COUNTY	TYRE, TOWN OF	08/31/1979 (M)
SENECA COUNTY	VARICK, TOWN OF	12/17/1987
SENECA COUNTY	WATERLOO, TOWN OF	09/16/1981
SENECA COUNTY	WATERLOO, VILLAGE OF	08/03/1981
ST. LAWRENCE COUNTY	BRASHER, TOWN OF	01/03/1986 (M)
ST. LAWRENCE COUNTY	CANTON, TOWN OF	08/17/1998
ST. LAWRENCE COUNTY	CANTON, VILLAGE OF	05/02/1994
ST. LAWRENCE COUNTY	CLARE, TOWN OF	07/16/1982 (M)
ST. LAWRENCE COUNTY	CLIFTON, CITY OF	05/15/1986 (M)
ST. LAWRENCE COUNTY	COLTON, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	DE KALB, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	DE PEYSTER, TOWN OF	07/23/1982 (M)
ST. LAWRENCE COUNTY	EDWARDS, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	EDWARDS, VILLAGE OF	07/23/1982 (M)
ST. LAWRENCE COUNTY	FINE, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	FOWLER, TOWN OF	06/05/1989 (M)
ST. LAWRENCE COUNTY	GOUVERNEUR, TOWN OF	08/06/1982 (M)
ST. LAWRENCE COUNTY	GOUVERNEUR, VILLAGE OF	03/03/1997
ST. LAWRENCE COUNTY	HAMMOND, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	HERMON, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	HERMON, VILLAGE OF	08/03/1998
ST. LAWRENCE COUNTY	HEUVELTON, VILLAGE OF	04/30/1986 (M)
ST. LAWRENCE COUNTY	HOPKINTON, TOWN OF	11/12/1982 (M)
ST. LAWRENCE COUNTY	LAWRENCE, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	LISBON, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	LOUISVILLE, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MACOMB, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MADRID, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	MASSENA, TOWN OF	06/17/1986 (M)
ST. LAWRENCE COUNTY	MASSENA, VILLAGE OF	11/5/1980
ST. LAWRENCE COUNTY	MORRISTOWN, TOWN OF	08/06/1982 (M)
ST. LAWRENCE COUNTY	MORRISTOWN, VILLAGE OF	12/02/1980 (M)
ST. LAWRENCE COUNTY	NORFOLK, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	NORWOOD, VILLAGE OF	04/30/1986 (M)
ST. LAWRENCE COUNTY	OGDENSBURG, CITY OF	11/5/1980
ST. LAWRENCE COUNTY	OSWEGATCHIE, TOWN OF	05/01/1985 (M)
ST. LAWRENCE COUNTY	PARISHVILLE, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	PIERCEFIELD, TOWN OF	01/06/1984 (M)
ST. LAWRENCE COUNTY	PIERREPONT, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	PITCAIRN, TOWN OF	08/13/1982 (M)
ST. LAWRENCE COUNTY	POTSDAM, VILLAGE OF	01/05/1996
ST. LAWRENCE COUNTY	POTSDAM,TOWN OF	03/04/1986 (M)
ST. LAWRENCE COUNTY	RENSSELAER FALLS, VILLAGE OF	01/06/1984 (M)
ST. LAWRENCE COUNTY	RICHVILLE, VILLAGE OF	01/06/1984 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
ST. LAWRENCE COUNTY	ROSSIE, TOWN OF	07/30/1982 (M)
ST. LAWRENCE COUNTY	RUSSELL, TOWN OF	(NSFHA)
ST. LAWRENCE COUNTY	STOCKHOLM, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	WADDINGTON, TOWN OF	04/15/1986 (M)
ST. LAWRENCE COUNTY	WADDINGTON, VILLAGE OF	05/11/1979 (M)
STEUBEN COUNTY	ADDISON, TOWN OF	12/18/1984
STEUBEN COUNTY	ADDISON, VILLAGE OF	06/15/1981
STEUBEN COUNTY	ARKPORT, VILLAGE OF	03/04/1980
STEUBEN COUNTY	AVOCA, TOWN OF	02/05/1992
STEUBEN COUNTY	AVOCA, VILLAGE OF	05/16/1983
STEUBEN COUNTY	BATH, TOWN OF	05/02/1983
STEUBEN COUNTY	BATH, VILLAGE OF	03/16/1983
STEUBEN COUNTY	BRADFORD, TOWN OF	09/24/1984 (M)
STEUBEN COUNTY	CAMERON, TOWN OF	05/15/1991
STEUBEN COUNTY	CAMPBELL, TOWN OF	06/11/1982
STEUBEN COUNTY	CANISTEO, TOWN OF	12/18/1984
STEUBEN COUNTY	CANISTEO, VILLAGE OF	05/18/1979 (M)
STEUBEN COUNTY	CATON, TOWN OF	03/23/1984 (M)
STEUBEN COUNTY	COHOCTON, TOWN OF	05/16/1983
STEUBEN COUNTY	COHOCTON, VILLAGE OF	05/16/1983
STEUBEN COUNTY	CORNING, CITY OF	09/27/2002
STEUBEN COUNTY	CORNING, TOWN OF	09/27/2002
STEUBEN COUNTY	DANSVILLE, TOWN OF	03/09/84(M)
STEUBEN COUNTY	ERWIN, TOWN OF	07/02/1980
STEUBEN COUNTY	FREMONT, TOWN OF	10/29/1982 (M)
STEUBEN COUNTY	GREENWOOD, TOWN OF	09/03/1982 (M)
STEUBEN COUNTY	HAMMONDSPORT, VILLAGE OF	04/17/1978
STEUBEN COUNTY	HARTSVILLE, TOWN OF	09/17/1982 (M)
STEUBEN COUNTY	HORNBY, TOWN OF	04/15/1986
STEUBEN COUNTY	HORNELL, CITY OF	03/18/1980
STEUBEN COUNTY	HORNELLSVILLE, TOWN OF	07/16/1980
STEUBEN COUNTY	HOWARD, TOWN OF	09/03/1982 (M)
STEUBEN COUNTY	JASPER, TOWN OF	07/23/1982 (M)
STEUBEN COUNTY	LINDLEY, TOWN OF	08/01/1980
STEUBEN COUNTY	NORTH HORNELL, VILLAGE OF	01/17/1986
STEUBEN COUNTY	PAINTED POST, VILLAGE OF	05/18/2000
STEUBEN COUNTY	PRATTSBURG, TOWN OF	01/20/1984 (M)
STEUBEN COUNTY	PULTENEY, TOWN OF	09/30/1977
STEUBEN COUNTY	RATHBONE, TOWN OF	12/03/1982 (M)
STEUBEN COUNTY	RIVERSIDE, VILLAGE OF	05/15/1980
STEUBEN COUNTY	SAVONA, VILLAGE OF	08/15/1980
STEUBEN COUNTY	SOUTH CORNING, VILLAGE OF	10/15/1981
STEUBEN COUNTY	THURSTON, TOWN OF	02/11/1983 (M)
STEUBEN COUNTY	TROUPSBURG, TOWN OF	09/24/1982 (M)
STEUBEN COUNTY	TUSCARORA, TOWN OF	03/01/1988 (L)
STEUBEN COUNTY	URBANA, TOWN OF	01/19/1978
STEUBEN COUNTY	WAYLAND, TOWN OF	06/08/1984 (M)
STEUBEN COUNTY	WAYLAND, VILLAGE OF	08/01/1988 (L)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
STEUBEN COUNTY	WAYNE, TOWN OF	11/2/1977
STEUBEN COUNTY	WEST UNION, TOWN OF	07/01/1988 (L)
STEUBEN COUNTY	WHEELER, TOWN OF	07/25/1980 (M)
STEUBEN COUNTY	WOODHULL, TOWN OF	04/02/1991
STEUBEN COUNTY/ALLEGANY COUNTY	ALMOND, TOWN OF	03/04/1980
SUFFOLK COUNTY	AMITYVILLE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	ASHAROKEN, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BABYLON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BABYLON,TOWN OF	09/25/2009
SUFFOLK COUNTY	BELLE TERRE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BELLPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BRIGHTWATERS, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	BROOKHAVEN,TOWN OF	09/25/2009
SUFFOLK COUNTY	DERING HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	EAST HAMPTON,TOWN OF	09/25/2009
SUFFOLK COUNTY	EAST HAMPTON,VILLAGE OF	09/25/2009
SUFFOLK COUNTY	GREENPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HEAD OF THE HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HUNTINGTON BAY, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	HUNTINGTON, TOWN OF	09/25/2009
SUFFOLK COUNTY	ISLANDIA, VILLAGE OF	09/25/2009 (M)
SUFFOLK COUNTY	ISLIP,TOWN OF	09/25/2009
SUFFOLK COUNTY	LAKE GROVE, VILLAGE OF	(NSFHA)
SUFFOLK COUNTY	LINDENHURST, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	LLOYD HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NISSEQUOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NORTH HAVEN, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	NORTHPORT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	OCEAN BEACH, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	OLD FIELD, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	PATCHOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	POQUOTT, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	PORT JEFFERSON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	QUOGUE, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	RIVERHEAD, TOWN OF	09/25/2009
SUFFOLK COUNTY	SAG HARBOR, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SAGAPONACK, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SALTAIRE,VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SHELTER ISLAND, TOWN OF	09/25/2009
SUFFOLK COUNTY	SHOREHAM, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SMITHTOWN, TOWN OF	09/25/2009
SUFFOLK COUNTY	SOUTHAMPTON, TOWN OF	09/25/2009
SUFFOLK COUNTY	SOUTHAMPTON, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	SOUTHOLD,TOWN OF	09/25/2009
SUFFOLK COUNTY	THE BRANCH, VILLAGE OF	09/25/2009
SUFFOLK COUNTY	WEST HAMPTON DUNES, VILLAGE O	09/25/2009
SUFFOLK COUNTY	WESTHAMPTON BEACH, VILLAGE OF	09/25/2009
SULLIVAN COUNTY	BETHEL, TOWN OF	02/18/2011

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
SULLIVAN COUNTY	BLOOMINGBURG, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	CALLICOON, TOWN OF	02/18/2011
SULLIVAN COUNTY	COCHECTON, TOWN OF	02/18/2011
SULLIVAN COUNTY	DELAWARE, TOWN OF	02/18/2011
SULLIVAN COUNTY	FALLSBURG, TOWN OF	02/18/2011
SULLIVAN COUNTY	FORESTBURGH, TOWN OF	02/18/2011
SULLIVAN COUNTY	FREMONT, TOWN OF	02/18/2011
SULLIVAN COUNTY	HIGHLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	JEFFERSONVILLE, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	LIBERTY, TOWN OF	02/18/2011
SULLIVAN COUNTY	LIBERTY, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	LUMBERLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	MAMAKATING, TOWN OF	02/18/2011
SULLIVAN COUNTY	MONTICELLO, VILLAGE OF	02/18/2011
SULLIVAN COUNTY	NEVERSINK, TOWN OF	02/18/2011 (M)
SULLIVAN COUNTY	ROCKLAND, TOWN OF	02/18/2011
SULLIVAN COUNTY	THOMPSON, TOWN OF	02/18/2011
SULLIVAN COUNTY	TUSTEN, TOWN OF	02/18/2011
SULLIVAN COUNTY	WOODRIDGE, VILLAGE OF	02/18/2011 (M)
SULLIVAN COUNTY	WURTSBORO, VILLAGE OF	02/18/2011
TIOGA COUNTY	BARTON, TOWN OF	05/15/1991
TIOGA COUNTY	BERKSHIRE, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	CANDOR, TOWN OF	08/19/1986
TIOGA COUNTY	CANDOR, VILLAGE OF	10/01/1991 (L)
TIOGA COUNTY	NEWARK VALLEY, TOWN OF	02/03/1982
TIOGA COUNTY	NEWARK VALLEY, VILLAGE OF	02/03/1982
TIOGA COUNTY	NICHOLS, TOWN OF	02/17/1982
TIOGA COUNTY	NICHOLS, VILLAGE OF	09/29/1986
TIOGA COUNTY	OWEGO, TOWN OF	01/17/1997
TIOGA COUNTY	OWEGO, VILLAGE OF	04/02/1982
TIOGA COUNTY	RICHFORD, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	SPENCER, TOWN OF	05/15/1985 (M)
TIOGA COUNTY	SPENCER, VILLAGE OF	05/15/1985 (M)
TIOGA COUNTY	TIOGA, TOWN OF	05/17/1982
TIOGA COUNTY	WAVERLY, VILLAGE OF	03/16/1983
TOMPKINS COUNTY	CAROLINE, TOWN OF	06/19/1985 (M)
TOMPKINS COUNTY	CAYUGA HEIGHTS, VILLAGE OF	(NSFHA)
TOMPKINS COUNTY	DANBY, TOWN OF	05/15/1985 (M)
TOMPKINS COUNTY	DRYDEN, TOWN OF	05/15/1985 (M)
TOMPKINS COUNTY	DRYDEN, VILLAGE OF	01/03/1979
TOMPKINS COUNTY	FREEVILLE, VILLAGE OF	05/01/88(L)
TOMPKINS COUNTY	GROTON, TOWN OF	10/05/1984 (M)
TOMPKINS COUNTY	GROTON, VILLAGE OF	11/5/1986
TOMPKINS COUNTY	ITHACA, CITY OF	09/30/1981
TOMPKINS COUNTY	ITHACA, TOWN OF	06/19/1985
TOMPKINS COUNTY	LANSING, TOWN OF	10/15/1985
TOMPKINS COUNTY	LANSING, VILLAGE OF	11/19/1987
TOMPKINS COUNTY	NEWFIELD, TOWN OF	10/15/1985 (M)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
TOMPKINS COUNTY	TRUMANSBURG, VILLAGE OF	04/01/1988 (L)
TOMPKINS COUNTY	ULYSSES, TOWN OF	02/19/1987
ULSTER COUNTY	DENNING, TOWN OF	05/25/1984 (M)
ULSTER COUNTY	ELLENVILLE, VILLAGE OF	09/25/2009
ULSTER COUNTY	ESOPUS, TOWN OF	09/25/2009
ULSTER COUNTY	GARDINER, TOWN OF	09/25/2009
ULSTER COUNTY	HARDENBURGH, TOWN OF	03/16/2089
ULSTER COUNTY	HURLEY, TOWN OF	08/18/2092
ULSTER COUNTY	KINGSTON, CITY OF	09/25/2009
ULSTER COUNTY	KINGSTON,TOWN OF	09/25/2009
ULSTER COUNTY	LLOYD, TOWN OF	09/25/2009
ULSTER COUNTY	MARBLETOWN, TOWN OF	09/25/2009
ULSTER COUNTY	MARLBOROUGH, TOWN OF	09/25/2009
ULSTER COUNTY	NEW PALTZ, TOWN OF	09/25/2009
ULSTER COUNTY	NEW PALTZ, VILLAGE OF	09/25/2009
ULSTER COUNTY	OLIVE, TOWN OF	11/1/1984
ULSTER COUNTY	PLATTEKILL, TOWN OF	(NSFHA)
ULSTER COUNTY	ROCHESTER, TOWN OF	09/25/2009
ULSTER COUNTY	ROSENDALE, TOWN OF	09/25/2009
ULSTER COUNTY	SAUGERTIES, TOWN OF	09/25/2009
ULSTER COUNTY	SAUGERTIES, VILLAGE OF	09/25/2009 (M)
ULSTER COUNTY	SHANDAKEN, TOWN OF	02/17/1989
ULSTER COUNTY	SHAWANGUNK, TOWN OF	09/25/2009
ULSTER COUNTY	ULSTER, TOWN OF	09/25/2009
ULSTER COUNTY	WAWARSING, TOWN OF	09/15/1983
ULSTER COUNTY	WOODSTOCK, TOWN OF	09/27/1991
WARREN COUNTY	BOLTON, TOWN OF	08/16/1996
WARREN COUNTY	CHESTER, TOWN OF	06/05/1985 (M)
WARREN COUNTY	GLENS FALLS, CITY OF	06/05/1985
WARREN COUNTY	HAGUE, TOWN OF	09/29/1996
WARREN COUNTY	HORICON, TOWN OF	02/15/1985 (M)
WARREN COUNTY	JOHNSBURG, TOWN OF	05/01/1985 (M)
WARREN COUNTY	LAKE GEORGE, TOWN OF	08/16/1996
WARREN COUNTY	LAKE GEORGE, VILLAGE OF	09/29/1996
WARREN COUNTY	LAKE LUZERNE, TOWN OF	05/01/1984
WARREN COUNTY	QUEENSBURY, TOWN OF	08/16/1996
WARREN COUNTY	STONY CREEK, TOWN OF	08/24/1984 (M)
WARREN COUNTY	THURMAN, TOWN OF	08/19/1986
WARREN COUNTY	WARRENSBURG, TOWN OF	03/01/1984
WASHINGTON COUNTY	ARGYLE, TOWN OF	08/24/1984 (M)
WASHINGTON COUNTY	ARGYLE, VILLAGE OF	05/18/1979 (M)
WASHINGTON COUNTY	CAMBRIDGE, TOWN OF	09/04/1985 (M)
WASHINGTON COUNTY	CAMBRIDGE, VILLAGE OF	01/02/2008
WASHINGTON COUNTY	DRESDEN, TOWN OF	09/20/1996
WASHINGTON COUNTY	EASTON, TOWN OF	11/20/1991
WASHINGTON COUNTY	FORT ANN, TOWN OF	11/5/1997
WASHINGTON COUNTY	FORT ANN, VILLAGE OF	(NSFHA)
WASHINGTON COUNTY	FORT EDWARD, TOWN OF	12/15/1982

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
WASHINGTON COUNTY	FORT EDWARD, VILLAGE OF	02/15/1984
WASHINGTON COUNTY	GRANVILLE, TOWN OF	08/05/1985 (M)
WASHINGTON COUNTY	GRANVILLE, VILLAGE OF	04/17/1985 (M)
WASHINGTON COUNTY	GREENWICH, VILLAGE OF	05/04/2000
WASHINGTON COUNTY	GREENWICH,TOWN OF	03/16/1992
WASHINGTON COUNTY	HAMPTON, TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	HARTFORD, TOWN OF	11/01/1985 (M)
WASHINGTON COUNTY	HEBRON, TOWN OF	06/15/1994
WASHINGTON COUNTY	HUDSON FALLS, VILLAGE OF	(NSFHA)
WASHINGTON COUNTY	JACKSON, TOWN OF	03/16/1992
WASHINGTON COUNTY	KINGSBURY, TOWN OF	09/07/1979 (M)
WASHINGTON COUNTY	PUTNAM, TOWN OF	11/20/1996
WASHINGTON COUNTY	SALEM, VILLAGE OF	04/17/1985 (M)
WASHINGTON COUNTY	SALEM,TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	WHITE CREEK, TOWN OF	04/17/1985 (M)
WASHINGTON COUNTY	WHITEHALL, TOWN OF	07/03/1986
WASHINGTON COUNTY	WHITEHALL, VILLAGE OF	06/03/1985 (M)
WAYNE COUNTY	ARCADIA, TOWN OF	11/2/1977
WAYNE COUNTY	BUTLER, TOWN OF	07/09/1982 (M)
WAYNE COUNTY	CLYDE, VILLAGE OF	12/18/1984
WAYNE COUNTY	GALEN, TOWN OF	05/16/1983
WAYNE COUNTY	HURON, TOWN OF	01/19/1996
WAYNE COUNTY	LYONS, TOWN OF	09/07/1979 (M)
WAYNE COUNTY	LYONS, VILLAGE OF	03/16/1983
WAYNE COUNTY	MACEDON, TOWN OF	01/05/1984
WAYNE COUNTY	MACEDON, VILLAGE OF	09/30/1983
WAYNE COUNTY	MARION, TOWN OF	07/01/1988 (L)
WAYNE COUNTY	NEWARK, VILLAGE OF	07/15/1988
WAYNE COUNTY	ONTARIO, TOWN OF	06/01/1978
WAYNE COUNTY	PALMYRA, TOWN OF	03/01/1978
WAYNE COUNTY	PALMYRA, VILLAGE OF	07/15/1988
WAYNE COUNTY	RED CREEK, VILLAGE OF	04/08/1983 (M)
WAYNE COUNTY	ROSE, TOWN OF	03/09/1984 (M)
WAYNE COUNTY	SAVANNAH, TOWN OF	08/06/1982 (M)
WAYNE COUNTY	SODUS POINT, VILLAGE OF	11/2/1977
WAYNE COUNTY	SODUS, TOWN OF	06/02/1992
WAYNE COUNTY	WALWORTH, TOWN OF	03/16/1983
WAYNE COUNTY	WILLIAMSON TOWN	10/17/1978
WAYNE COUNTY	WOLCOTT, TOWN OF	06/02/1992
WAYNE COUNTY	WOLCOTT, VILLAGE OF	07/06/1984 (M)
WESTCHESTER COUNTY	ARDSLEY, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BEDFORD, TOWN OF	09/28/2007
WESTCHESTER COUNTY	BRIARCLIFF MANOR, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BRONXVILLE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	BUCHANAN, VILLAGE OF	09/28/2007 (M)
WESTCHESTER COUNTY	CORTLANDT, TOWN OF	09/28/2007
WESTCHESTER COUNTY	CROTON-ON-HUDSON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	DOBBS FERRY, VILLAGE OF	09/28/2007

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
WESTCHESTER COUNTY	EASTCHESTER, TOWN OF	09/28/2007
WESTCHESTER COUNTY	ELMSFORD, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	GREENBURGH,TOWN OF	09/28/2007
WESTCHESTER COUNTY	HARRISON, TOWN OF	09/28/2007
WESTCHESTER COUNTY	HASTINGS-ON-HUDSON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	IRVINGTON, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	LARCHMONT, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	LEWISBORO, TOWN OF	09/28/2007 (M)
WESTCHESTER COUNTY	MAMARONECK, TOWN OF	09/28/2007
WESTCHESTER COUNTY	MAMARONECK, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	MOUNT KISCO, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	MOUNT PLEASANT, TOWN OF	09/28/2007
WESTCHESTER COUNTY	MOUNT VERNON, CITY OF	09/28/2007
WESTCHESTER COUNTY	NEW CASTLE, TOWN OF	09/28/2007
WESTCHESTER COUNTY	NEW ROCHELLE, CITY OF	09/28/2007
WESTCHESTER COUNTY	NORTH CASTLE, TOWN OF	09/28/2007
WESTCHESTER COUNTY	NORTH SALEM, TOWN OF	09/28/2007
WESTCHESTER COUNTY	OSSINING, TOWN OF	09/28/2007
WESTCHESTER COUNTY	OSSINING, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PEEKSKILL, CITY OF	09/28/2007
WESTCHESTER COUNTY	PELHAM MANOR, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PELHAM, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PLEASANTVILLE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	PORT CHESTER, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	POUND RIDGE, TOWN OF	09/28/2007
WESTCHESTER COUNTY	RYE BROOK, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	RYE, CITY OF	09/28/2007
WESTCHESTER COUNTY	SCARSDALE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	SLEEPY HOLLOW, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	SOMERS, TOWN OF	09/28/2007
WESTCHESTER COUNTY	TARRYTOWN, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	TUCKAHOE, VILLAGE OF	09/28/2007
WESTCHESTER COUNTY	WHITE PLAINS, CITY OF	09/28/2007
WESTCHESTER COUNTY	YONKERS, CITY OF	09/28/2007
WESTCHESTER COUNTY	YORKTOWN, TOWN OF	09/28/2007
WYOMING COUNTY	ARCADE, TOWN OF	03/03/1992
WYOMING COUNTY	ARCADE, VILLAGE OF	03/03/1992
WYOMING COUNTY	ATTICA, TOWN OF	04/30/1986
WYOMING COUNTY	BENNINGTON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	CASTILE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	CASTILE, VILLAGE OF	05/28/1982 (M)
WYOMING COUNTY	COVINGTON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	EAGLE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	GAINESVILLE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	GAINESVILLE, VILLAGE OF	02/15/1985 (M)
WYOMING COUNTY	GENESEE FALLS, TOWN OF	05/01/1984
WYOMING COUNTY	JAVA, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	ORANGEVILLE, 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 COUNTY	PERRY, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	PERRY, VILLAGE OF	07/29/1977 (M)
WYOMING COUNTY	PIKE, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	PIKE, VILLAGE OF	06/18/1982 (M)
WYOMING COUNTY	SHELDON, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	SILVER SPRINGS, VILLAGE OF	01/20/1984 (M)
WYOMING COUNTY	WARSAW, TOWN OF	12/23/1983 (M)
WYOMING COUNTY	WARSAW, VILLAGE OF	11/18/1981
WYOMING COUNTY	WETHERSFIELD, TOWN OF	07/16/1982
WYOMING COUNTY	WYOMING, VILLAGE OF	08/03/1981
YATES COUNTY	BARRINGTON, TOWN OF	03/09/1984 (M)
YATES COUNTY	BENTON, TOWN OF	01/20/1984 (M)
YATES COUNTY	DRESDEN, VILLAGE OF	06/15/1981
YATES COUNTY	DUNDEE, VILLAGE OF	03/01/1988 (L)
YATES COUNTY	ITALY, TOWN OF	03/07/2001
YATES COUNTY	JERUSALEM, TOWN OF	01/20/1984 (M)
YATES COUNTY	MIDDLESEX, TOWN OF	09/29/1989
YATES COUNTY	MILO, TOWN OF	07/18/1985 (M)
YATES COUNTY	PENN YAN, VILLAGE OF	06/15/1981
YATES COUNTY	POTTER, TOWN OF	03/23/1984 (M)
YATES COUNTY	RUSHVILLE, VILLAGE OF	06/05/1985 (M)
YATES COUNTY	STARKEY, TOWN OF	12/3/1987
YATES COUNTY	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 – June 29, 2011."
(http://www.fema.gov/fema/csb.shtm)

Appendix 2

1992 SEQRA Findings Statement on the GEIS on the Oil, Gas and Solution Mining Regulatory Program

Final

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
Division of Mineral Resources

Date

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Appendix 3

Supplemental SEQRA Findings Statement on Leasing of State Lands for Activities Regulated Under the Oil, Gas and Solution Mining Law

Final

Supplemental Generic Environmental Impact Statement

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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

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Appendix 4

EXISTING
Application Form for Permit to Drill, Deepen, Plug Back or Convert A Well Subject to the Oil, Gas and Solution Mining Regulatory Program

Final

Supplemental Generic Environmental Impact Statement

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Print Form

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

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 ☐ Sidetrack

TYPE OF WELL: (Check one)
☐ New ☐ Existing

Existing API Well Identification Number
31- | | | - | | | | | - | | - | |

TYPE OF WELL BORE: (Check one)
☐ Vertical ☐ Directional ☐ Horizontal

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

71/2 MINUTE QUAD NAME	QUAD SECTION	PROPOSED TARGET FORMATION

LOCATION DESCRIPTION	TVD	TMD	Decimal Latitude (NAD83)	Decimal Longitude (NAD83)
Surface			□□.□□□□□□	□□.□□□□□□
Kickoff			□□.□□□□□□	□□.□□□□□□
Top of Target Interval			□□.□□□□□□	□□.□□□□□□
Bottom of Target Interval			□□.□□□□□□	□□.□□□□□□
Bottom Hole			□□.□□□□□□	□□.□□□□□□

PROPOSED WELL DATA

WELL TYPE	PLANNED DATE OF COMMENCEMENT OF OPERATIONS
SURFACE ELEVATION (check how obtained) _______ ft ☐ Surveyed ☐ Topo Map ☐ Other ________	TYPE OF TOOLS

NAME OF PLANNED DRILLING CONTRACTOR (as registered with the Division)	TELEPHONE NUMBER (include area code)

PROPOSED SPACING DATA

WELL SPACING TYPE (subject to Article 23, Title 5)	TYPE OF UNIT (conforms to spacing under either Title 5 or Part 553)	NUMBER OF ACRES IN UNIT
☐ Title 5 ☐ Non-Title 5	☐ Conforming ☐ Non-Conforming	
ACREAGE CONTROLLED IN UNIT ☐ 100% ☐ ≥ 60% AND <100%	ACREAGE CONTROLLED IN BORE HOLE (throughout entire hole) ☐ Yes ☐ No	STATE LANDS (leased or unitized)

DEPARTMENT USE ONLY

APD NUMBER	BOND NUMBER	RECEIPT NUMBER
PERMIT FEE	API WELL IDENTIFICATION NUMBER 31-	DATE ISSUED

APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT

WELL NAME	WELL NUMBER	NAME OF OWNER

PROPOSED CASING AND CEMENTING DATA

CASING DATA

Feature	Size (in.)	Top (ft.)	Bottom (ft.)	Weight (lbs.)	New Pipe	Comments

CEMENT DATA

Feature	Top (ft.)	Bottom (ft.)	Volume ($ft.^3$)	Cement Class (include excess)*	No. of Sacks*	Weight (PPG)	Yield ($ft.^3$/sx)	Vol. ($ft.^3$)*	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 that organization to make this application; that this application was prepared by me or under my supervision and direction, is true to the best of my knowledge and belief; 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 noncompliance with the terms and conditions of the permit.

____
Printed or Typed Name of Authorized Representative

______________________________ ______________
Signature of Authorized Representative Date

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Appendix 5

EXISTING
Environmental Assessment Form
For Well Permitting

Final

Supplemental Generic Environmental Impact Statement

www.dec.ny.gov

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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 describe ____________________

____

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 ____________________		
____________________		

Printed or Typed Name and Affiliation of Preparer

Printed or Typed Name of Authorized Representative (See below note)

Signature of Authorized Representative (See below note)	Date

Note: The Authorized Representative must be listed in Box 7 of the Organizational Report on file with the Division of Mineral Resources

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 OF OPPORTUNITY. | Department of Environmental Conservation

Appendix 6

PROPOSED
Environmental Assessment Form
Addendum

Final

Supplemental Generic Environmental Impact Statement

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PROPOSED EAF ADDENDUM REQUIREMENTS
FOR HIGH-VOLUME HYDRAULIC FRACTURING

REQUIRED INFORMATION

- Minimum depth and elevation of top of objective formation or 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, by product name and purpose/type
  - Documentation of the applicant's evaluation of available alternatives for the proposed additive products that are efficacious but which exhibit reduced aquatic toxicity and pose less risk to water resources and the environment

- Proposed volume of water and each additive product to be used in hydraulic fracturing

- Proposed % by weight of water, proppants and each additive

- Water source for hydraulic fracturing
  - If a newly proposed surface water source (not previously approved by the Department as part of a well permit application):
    - Type of withdrawal (stream, lake, pond, groundwater, etc.)
    - Location of water withdrawal point, status of RBC approval if applicable
    - List and location of all private water wells within 500 feet of the proposed water withdrawal point
    - For proposed withdrawals from lakes and ponds:
      - Estimates of the maximum change in storage resulting from the proposed withdrawals, including estimates of inflow into the water body, precipitation onto water surface, existing and proposed water withdrawals, evaporation from water surface, and releases from water body
    - For proposed groundwater withdrawals:
      - Identification of and shortest distance to any wetland within 500 feet of the proposed withdrawal point
      - Results of pump testing as referenced in the SGEIS, including evaluation of any potential influence on wetland(s) within 500 feet
    - 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 gage on the stream; if yes:
      - Distance to stream gage
      - Upstream or downstream of stream gage
      - Changes in stream flow (e.g., other withdrawals, diversions, tributary input) between gage and withdrawal point
      - Years of stream gage data available and period of record

- If a previously proposed or Department-approved surface water source:
  - API # of well permit application associated with previous proposal or approval

- Scaled distance from surface location of well and closest edge of well pad to:
  - Any known water supply reservoir, river or stream intake, water well or domestic-supply spring within 2,640 feet, including public or private wells, community or non-community systems
  - Any primary or principal aquifer boundary, perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet
  - All residences, occupied structures or places of assembly within 1,320 feet

- Capacity of rig fueling tank(s) and distance to:
  - Any 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 location(s) of the fueling tank(s)

- 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 NYSDOH definitions)
  - Type of facility or establishment if not a residence

- Identification of any well listed in Department's Oil & Gas Database, or any other abandoned well identified by property owners or tenants, within the spacing unit of the proposed well and/or within 1 mile (5,280 feet) of the proposed well location. For each well identified, provide the following information:
  - Well name and API Number
  - Distance from proposed surface location of well to surface location of existing well
  - Well Type
  - Well Status
  - Well Orientation
  - Quantity and type of any freshwater, brine, oil or gas encountered during drilling, as recorded on the Department's Well Drilling and Completion Report

- Information about the planned construction and capacity of the reserve pit, if any, and an indication of the timing of the use of a closed-loop tank system (e.g., surface, intermediate and/or production hole)

- Information about the number and individual and total capacity of receiving tanks for flowback water

PROPOSED EAF ADDENDUM REQUIREMENTS
FOR HIGH-VOLUME HYDRAULIC FRACTURING

- 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

- Identify the EPA Tiers of the drilling and hydraulic fracturing engines used, if these use gasoline or diesel fuel. If particulate traps or Selective Catalytic Reduction (SCR) are not used, provide a description of other control measures planned to reduce particulate matter and NO_x emissions during the drilling and hydraulic fracturing processes

- If condensate tanks are to be used, provide their capacity and the vapor recovery system to be used

- If a wellhead compressor is used, provide its size in horsepower. Describe the control equipment used for NO_x

- If a glycol dehydrator is to be used at the well pad, provide its stack height and the capacity of glycol to be used on an annual basis

- Information on the status of a sales line and interconnecting gathering line to the well or multi-well pad (i.e., is there currently a line in place or is one expected to be in place prior to conducting hydraulic fracturing operations to facilitate a Reduced Emissions Completion [REC])
    - If REC will not be used, the following must be provided
        - an estimate of how much total gas (MMcf) will be vented and flared during flowback
        - an estimate of how much total gas (MMcf) was previously vented and flared during flowback on the same well pad in the previous 12 months

- Well information with respect to local planning documents
    - Identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies
    - Identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s)

REQUIRED ATTACHMENTS

- Scaled, stamped well plat showing the following:
    - Plan view of wellbore including surface and bottom-hole locations
    - Well pad close-up showing placement of fueling tank(s), reserve pit and receiving tanks for flowback water

  - Vertical section of wellbore showing the land surface elevation and wellbore elevation with an indication of the minimum depth of the wellbore within the objective formation or zone as required above

- A Material Safety Data Sheet (MSDS) for each additive product proposed for use in hydraulic fracturing, if not already on file with the Department

- 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
  - location of access road
  - location of any flowback water pipelines or conveyances

- Evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within one half-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 Department Water Well search (http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty)

- Evidence of diligent efforts by the well operator to determine the existence and condition of abandoned wells within the proposed spacing unit and/or within one mile of the proposed well location
  - Printed results of Department Oil & Gas database search
  - List of property owners and tenants contacted for abandoned well information

- For a newly proposed water withdrawal, topographic map showing:
  - The location of the proposed withdrawal
  - All private water wells within 500 feet of the proposed water withdrawal point
  - For proposed surface water withdrawals:
    - Drainage area above the withdrawal point
  - For proposed groundwater withdrawals:
    - Identification of and shortest distance to any Department-regulated wetland within 500 feet of the proposed withdrawal point

- Invasive Species Management Plan that includes:
  - Survey of the entire well site, documenting the presence, location, and identity of any invasive plant species;
  - Specific protocols or best management practices for preventing the spread or introduction of invasive species at the site;
  - Specific protocols for the restoration of native plant cover on the site; and

  - Identification of any Certified Pesticide Applicator, if applicable.

- A Partial Site Reclamation Plan that describes the methods for partially reclaiming the site after well completion. Partial reclamation shall be compatible with sound environmental management practices and minimize negative environmental impacts.

- A description of methods for final reclamation of the well site following plugging of all the wells on the well pad. Reclamation methods shall be compatible with sound environmental management practices and minimize negative environmental impacts from the well pad.

- Proposed fluid disposal plan, pursuant to 6 NYCRR 554.1(c)(1)
  - Planned transport of flowback water and production brine 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 and production brine – 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 Department 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 centralized tank facility in New York:
      - Location, affirmation of ownership or permission
      - Certification of compliance with 360-6.3

- Proposed cuttings disposal plan for any drilling requiring cuttings to be disposed of off-site including at a landfill.
  - Planned disposition of cuttings – landfill or other (describe)
    - If a landfill in NY:
      - Name, owner/operator, location
      - Part 360 permit # and date if applicable

- Proposed blow-out preventer (BOP) use and test plan for all drilling and completion operations including:
  - Pressure rating of any:
    - Annular preventer
    - Rams including a description of type and number of rams
    - Choke manifold and connecting line (from BOP to choke manifold)

  - Timing and frequency of testing and/or visual inspection of BOP and related equipment including any scheduled retesting of equipment. Test pressure(s) and duration of test(s) including an explanation as to how the test pressure was determined
  - Test pressure(s) and timing for any internal pressure testing of surface, intermediate and production casing strings, and duration of test including an explanation as to how the test pressure was determined
  - Test pressure (psi/ft) and anticipated depth (TVD-ft) of any surface and/or intermediate casing seat integrity tests
    - If a casing seat integrity test will not be conducted on a casing string with a BOP installed on it, an explanation must be provided why such a test is not required and how any flow will be managed
  - System for recording, documenting and retaining the results of all pressure tests and inspections, and making such available to the Department
  - Copy of the operator's well control barrier policythat identifies acceptable barriers to be used during identified operations
  - Minimum distance from well for remote actuator (powered by a source other than rig hydraulics)

- Transportation plan developed by a NYS-licensed Professional Engineer, that specifies proposed routes and includes a road condition assessment.

- Noise mitigation plan, including any proposed mitigation measures for any occupied structure within 1,000 feet.

- If a new well pad is proposed in a Forest or Grassland Focus Area and involves disturbance in a contiguous forest patch of 150 acres or more in size or a contiguous grassland patch of 30 acres or more in size, then the Applicant should not submit this EAF or a well permit application prior to conducting a site-specific ecological assessment in accordance with a detailed study plan that has been approved by the Department. The need and plan for an ecological assessment should be determined in consultation with the Department and will consider information such as existing site conditions, existing covertype and ongoing and historical land management activities. The completed ecological assessment must be attached to this EAF and must include, at a minimum:
  - a compilation of historical information on use of the area by forest interior birds or grassland birds;
  - results of pre-disturbance biological studies, including a minimum of one year of field surveys at the site to determine the current extent, if any, of use of the site by forest interior birds or grassland birds;
  - an evaluation of potential impacts on forest interior or grassland birds from the project;
  - additional mitigation measures proposed by the applicant; and
  - protocols for monitoring of forest interior or grassland birds during the construction phase of the project and for a minimum of two years following well completion.

PROPOSED EAF ADDENDUM REQUIREMENTS
FOR HIGH-VOLUME HYDRAULIC FRACTURING

REQUIRED AFFIRMATIONS

- Any surface water withdrawal associated with this well pad will only occur when flow is above the appropriate threshold as described in the SGEIS

- Applicable FIRM and Flood Boundary and Floodway maps consulted, and proposed well pad and access road are not within a mapped100-year floodplain

- Baseline residential well sampling, analysis and ongoing monitoring will be conducted and results shared with property owner 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

- HVHF GP authorization for stormwater discharges will be obtained prior to site disturbance

- 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
    - 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
    - an acid rock drainage (ARD) mitigation plan consistent with the SGEIS for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings

- Operator will utilize alternative hydraulic fracturing additive products that exhibit reduced aquatic toxicity and pose less risk to water resources and the environment, unless demonstrated to DMN’s satisfaction that they are not equally effective or feasible

- Operator will prepare and adhere to an emergency response plan (ERP) consistent with the SGEIS that will be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit

- Operator will adhere to all well permit conditions and approved plans, including requirement for Department approval prior to making any change

- Operator will adhere to best management practices for reducing direct impacts to terrestrial habitats and wildlife consistent with the SGEIS (see Section 7.4.1.1)

ADDITIONAL SUBMISSION REQUIRED PRIOR TO SITE DISTURBANCE

- Copy of any road use agreement between the operator and local municipality

ADDITIONAL SUBMISSION REQUIRED AT LEAST 48 HOURS PRIOR TO WELL SPUD

- Copy of the ERP in electronic form

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Appendix 7

Sample Drilling Rig Specifications

Provided by Chesapeake Energy

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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: 2 – NOV D285P-LP Desander: Brandt - 2 - 10” Cones Desilter: Brandt - 12 - 4” Cones Agitators: 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

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Appendix 8

EXISTING
Casing and Cementing Practices Required for All Wells in NY

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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.

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Appendix 9

EXISTING
Fresh Water Aquifer Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers

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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.**

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Appendix 10

PROPOSED
Supplementary Permit Conditions
For High-Volume Hydraulic Fracturing

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PROPOSED Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

Note: The operator must comply with all provisions of Attachment A and Attachment B as noted at the end of this document, along with Attachment C when applicable.

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; and

   b) a greenhouse gas emissions impacts mitigation plan consistent with the SGEIS.

2) An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.

3) The county emergency management office (EMO) must be notified of the well's location including latitude and longitude (NAD 83) as follows:

   a) prior to spudding the well;

   b) first occurrence of flaring while drilling;

   c) prior to high-volume hydraulic fracturing, and;

   d) prior to flaring for well clean-up, treatment or testing. A flare permit from the Department is required prior to any flaring operation 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.

4) The operator shall adhere to the Department-approved transportation plan which shall be incorporated by reference into this permit. In addition, 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 a copy of any road use agreement between the operator and municipality.

5) Prior to site disturbance (for a new well pad) or spud (for an existing pad), the 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 within 30 days of the operator's receipt of laboratory results. If no residential water 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 or for other reasonable cause.

7) Water well analysis must be performed by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the property owner must be maintained by the operator. The results of the analyses (data) and delivery documentation must be made available to the Department and local health department upon Department request at any time during the period up to and including five years after the permitted hydrocarbon well is permanently plugged and abandoned under a Department permit. If the permitted hydrocarbon well is located on a multi-well pad, all residential water well data and delivery documentation must be maintained and made available during the period up to and including five years after the last permitted hydrocarbon well on the pad is permanently plugged and abandoned under a Department permit.

Site Preparation

8) Unless otherwise required by private lease agreement and in consideration of avoiding bisection of agricultural fields, to the extent practical the access road must be located as far away as possible 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, stabilized and remain on site for use in final reclamation.

10) Authorization under the Department's General Permit for Stormwater Discharges Associated with High-Volume Hydraulic Fracturing (HVHF GP) must be obtained prior to any disturbance at the site.

11) Piping, conveyances, valves and tanks in contact with 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) Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks, (SPOTS 10) is required for all fueling tanks;

14) To the extent practical, fueling tanks must not be placed within 500 feet of a public or private waterwell, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;

15) Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;

16) Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.

17) A copy of the SWPPP must be available on-site and available to Department inspectors while HVHF GP coverage is in effect. HVHF GP coverage may be terminated upon the plugging and abandonment of all wells on the well pad in accordance with Department-issued permits.

18) Two feet of freeboard must be maintained at all times for any on-site pit.

19) Except for freshwater storage pits, fluids must be removed from an on-site pit prior to any 45-day gap in use (i.e., from the completion date of the well) and the pit must be inspected by a Department inspector prior to resumed use.

Drilling, Stimulation and Flowback

NOTE: Wildcat Supplementary Conditions may be separately imposed in addition to these. Unless superseded by more stringent conditions below, the Department's Casing and Cementing Practices also remain in effect.

20) Lighting and noise mitigation measures as deemed necessary by the Department may be required at any time.

21) 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.

22) Individual crew member's responsibilities for blowout control must be posted in the doghouse or other appropriate location and each crew member must be made aware of such

responsibilities prior to spud of any well being drilled or when another rig is moved on a previously spudded well and/or prior to the commencement of any rig, snubbing unit or coiled tubing unit performing completion work. During all drilling and/or completion operations when a BOP is installed, tested or in use, the operator or operator's designated representative must be present at the wellsite and such person or personnel must have a current well control certification from an accredited training program that is acceptable to the Department (e.g., International Association of Drilling Contractors). Such certification must be available at the wellsite and provided to the Department upon request.

23) Appropriate pressure control procedures and equipment in proper working order must be properly installed and employed while conducting drilling and/or completion operations including tripping, logging, running casing into the well, and drilling out solid-core stage plugs. Unless otherwise approved by the Department, a snubbing unit and/or coiled tubing unit with a BOP must be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs.

24) Pressure testing of the blow-out preventer (BOP) and related equipment for any drilling and/or completion operation must be performed in accordance with the approved BOP use and test plan, and any deviation from the approved plan must be approved by the Department. Testing must be conducted in accordance with American Petroleum Institute (API) Recommended Practice (RP) 53, RP for Blowout Prevention Systems for Drilling Wells, or other procedures approved by the Department. Unless otherwise approved by the Department, the BOP use and test plan must include the following provisions:

    a) A system for recording, documenting and retaining the results of all pressure tests and inspections conducted during drilling and/or completion operations. The results must be available to the Department at the wellsite during the corresponding operation, and to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all pressure testing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each pressure test, at a minimum, must identify the equipment or casing being tested, the date of the test, the minimum and maximum test pressures in psig, the test medium (e.g., water, brine, mud, air, nitrogen) including its density, test duration, and the results of the test including any pressure drop;

    b) A well control barrier policy developed by the operator that identifies acceptable barriers to be used during identified operations. Such policy must employ, at a minimum, two mechanical barriers capable of being tested when conducting any drilling and/or completion operation below the surface casing. In no event shall a stripper rubber or a stripper head be considered an acceptable barrier;

    c) BOP testing prior to being put into service. Such testing must include testing after the BOP is installed on the well but prior to use. Pressure control equipment, including the BOP, that fails any pressure test must not be used until it is repaired and passes the pressure test, and;

    d) A remote BOP actuator which is powered by a source other than rig hydraulics that is located at least 50 feet from the wellhead. All lines, valves and fittings between the BOP and the remote actuator and any other actuator must be flame resistant and have an appropriate rated working pressure.

25) The operator must detect, if practical, and document all naturally occurring methane in the conductor hole, if drilled, and the surface hole. Further, in accordance with 6 NYCRR 554.7(b), all freshwater, brine, oil and gas shows must be documented on the Department's *Well Drilling and Completion Report*. In the event H_2S is encountered in any portion of the well, 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."

26) Annular disposal of drill cuttings or fluid is prohibited.

27) 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.

28) A closed-loop tank system must be used instead of a reserve pit to manage and contain drilling fluids and cuttings for any of the following:

    a) horizontal drilling in the Marcellus Shale without an acid rock drainage mitigation plan for on-site burial of such cuttings, and;

    b) any drilling requiring cuttings to be disposed of off-site including at a landfill.

29) With respect to the closed-loop tank system, cuttings may be removed from the site in the primary capture container (e.g., tank or bin) or transferred onsite via a transfer area to a secondary container or truck for offsite disposal. If a cuttings transfer area is employed, it must be lined with a material acceptable to the department. Transfer of cuttings to an onsite stock pile is prohibited, regardless of any liner under the stock pile. Offsite transport of all cuttings 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.

30) 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.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

    a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive;

e) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

g) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

h) after the cement is pumped, the operator must wait on cement (WOC):
   (1) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and
   (2) a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig, and;

i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.

32) The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned. This office must be notified _______ hours prior to surface casing cementing operations. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

33) Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's

approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.

34) This office must be notified ______ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

35) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

36) Production casing must be run to the surface. This office must be notified _______ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD). Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval. The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

37) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.

38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.

39) Under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test.

40) If hydraulic fracturing operations are performed down casing, prior to introducing hydraulic fracturing fluid into the well the casing extending from the surface of the well to the top of

the treatment interval must be tested with fresh water, mud or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. This pressure test may not commence for at least 7 days after the primary cementing operations are completed on this casing string. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

41) Prior to commencing hydraulic fracturing and pumping of hydraulic fracturing fluid, the injection lines and manifold, associated valves, frac head or tree and any other wellhead component or connection not previously tested must be tested with fresh water, mud or brine 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 hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

42) 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 including a treatment plan, must be submitted to and received by the regional office at least 3 days prior to commencement of high-volume hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well [i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)].

43) Fracturing products other than those identified in the well permit application materials may not be used without specific approval from this office.

44) This permit does not authorize the use of diesel as the primary carrier fluid (i.e., diesel-based hydraulic fracturing).

45) 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* and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing, 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*.

46) Hydraulic fracturing operations must be conducted as follows:

    a) Secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required. Secondary containment measures may include, as deemed appropriate by the Department, one or a combination of the following; dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance. Any such secondary containment must be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order. The results of this inspection must be recorded and documented by the operator, and available to the Department upon request;

b) At least two vacuum trucks must be on standby at the wellsite during the pumping of hydraulic fracturing fluid and during any subsequent flowback phases;

c) Hydraulic fracturing additives must be removed from the site if the site will be unattended;

d) Any hydraulic fracturing 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 hydraulic fracturing string-casing annulus to a covered watertight steel tank or covered watertight tank made of another material approved by the Department in case of hydraulic fracturing string failure. The relief valve must be set to limit the annular pressure to no more than 95% of the working pressure rating of the casings forming the annulus. The annulus between the hydraulic fracturing string and casing must be pressurized to at least 250 psig and monitored;

e) The pressure exerted on treating equipment including valves, lines, manifolds, hydraulic fracturing head or tree, casing and hydraulic fracturing string, if used, must not exceed 95% of the working pressure rating of the weakest component;

f) The hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during hydraulic fracturing operations;

g) All annuli available at the surface 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, and;

h) Hydraulic fracturing pumping operations must be immediately suspended if any anomalous pressure and/or flow condition is indicated or occurring including a significant deviation from the treatment plan (i.e., profile showing anticipated pressures and volume of fluid for pumping the first stage) provided to the Department with the *Pre-Frac Checklist and Certification* or any other anticipated pressure and/or flow condition. Suspension of operations due to an anomalous pressure and/or flow condition is considered a non-routine incident which must be reported in accordance with the General Provisions of these supplementary permit conditions. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

47) 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 period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all hydraulic fracturing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each well must include all types and volumes of materials, including additives, pumped into the well, flowback rates, and the daily and total volumes of fluid recovered during the first 30 days of flow from well. 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 Department's *Well Drilling and Completion Report* which must be provided to the Department within 30 days after completing the well in accordance with 6 NYCRR 554.7.

48) Flowback water is prohibited from being directed to or stored in any on-site pit. Covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department are required for flowback handling and containment on the well pad. Flowback water tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition. 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. Additionally, during transfer operations, all interconnecting piping must be manned if not visible to transfer personnel at the truck and tank.

49) 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 H_2S has been demonstrated at a previous well on the same pad. Gas vented through the flare stack must be ignited whenever possible. The stack must be equipped with a self-ignition device.

50) A reduced emissions completion, with minimal flaring (if any), must be performed whenever a sales line and interconnecting gathering line are available during completion at any individual well or a multi-well pad.

51) 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.

Reclamation

52) 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)(3). Flowback water must be removed from on-site tanks within the same time frame.

53) 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.

54) 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 disposition and use at that destination or receiving facility.

55) Cuttings contaminated with oil-based mud and polymer-based muds must be contained and managed in a closed-loop tank system and not be buried on site, and must be removed from the site for disposal in a 6 NYCRR Part 360 solid waste facility. Consultation with the Department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives. Any sampling and analysis directed by DMM 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 and to the extent practical, excess pit liner material must be removed and disposed of properly. Permission of the surface owner is required for any on-site burial of cuttings 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 cuttings 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.

56) A site-specific acid rock drainage (ARD) mitigation plan consistent with the SGEIS must be prepared by the operator and followed for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings. The plan must be available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place.

57) The operator must fully implement the Partial Site Reclamation Plan described in the approved application materials.

58) Final reclamation of the wellsite must be approved by the Department. 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

59) The operator must follow applicable best management practices (BMPs) for reducing direct impacts at individual well pads described in Section 7.4.1.1 of the SGEIS.

60) The operator must fully implement the Invasive Species Management Plan described in the approved application materials.

61) The operator must follow applicable best management practices (BMPs) for reducing the potential for transfer and introduction of invasive species described in Section 7.4.2.2 of the SGEIS.

62) 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. In accordance with 6 NYCRR 554.7, the well operator must provide the Department with the *Well Drilling and Completion Report* within 30 days after completing the well.

63) Any non-routine incident of potential environmental and/or public safety significance must be verbally reported to the Department within two hours of the incident's known occurrence or discovery, with a written report detailing the non-routine incident to follow within twenty-four hours of the incident's known occurrence or discovery. Non-routine incidents may include, but are not limited to: casing, drill pipe or hydraulic fracturing 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 other wells, observed effects at water wells or at the surface, complaints of water well contamination, anomalous pressure and/or flow conditions indicated or occurring during hydraulic fracturing operations, or other potentially polluting non-routine incident or incident that may affect the health, safety, welfare, or property of any person. Provided the environment and public safety would not be further endangered, any action and/or condition known or suspected of causing and/or contributing to a non-routine incident must cease immediately upon known occurrence or discovery of the incident, and appropriate initial remedial actions commenced. The required written non-routine incident report noted above must provide details of the incident and include, as necessary, a proposed remedial plan for Department review and approval. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.

65) Periodic radiation surveys must be conducted at specified time intervals during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols.

66) Production brine is prohibited from being directed to or stored in any on-site pit. Covered watertight steel, fiberglass or plastic tanks, or covered watertight tanks constructed of another material approved by the Department, are required for production brine handling and containment on the well pad. Production brine tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition.

67) Production 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.

ATTACHMENT A

To avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions are imposed:

1. The diesel fuel used in drilling and completion equipment engines will be limited to Ultra Low Sulfur Fuel (ULSF) with a maximum sulfur content of 15 ppm.

2. There will not be any simultaneous operations of the drilling and completion equipment engines at the single well pad.

3. The maximum number of wells to be drilled and completed annually or during any consecutive 12-month period at a single pad will be limited to four.

4. The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, then the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to 1 Tpy.

5. Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions.

6. During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12-month period. If "sour" gas is encountered with detected H_2S emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m).

7. During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12-month period.

8. Wellhead compressor will be equipped with NSCR controls.

9. No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines will be used for any activity at the well sites.

10. The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

11. The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

ATTACHMENT B

PASSBY FLOW IMPLEMENTATION AND ENFORCEMENT

1. Monitoring and Reporting**.** Passby flows must be maintained instantaneously. Determinations of allowable removal rates will be made based on comparisons with instantaneous flow data.

2. Description of Gage Types

Tier I- Gage data in this category is collected by the permitee immediately downstream of the water withdrawal location using streamflow gage equipment capable of accurately measuring instantaneous flow rates as approved at the discretion of the Department.

Tier II- Gage data in this category is obtained from acceptable USGS gages that must be located at a point in the same watershed where the drainage area at the gage is from 0.5x to 2.0x the size of the drainage area as measured at the withdrawal point. The catchment area must not have altered flows unless the instantaneous flow measurements can take into account the alterations.

Tier III- Gage data in this category is obtained from USGS gages that are either outside the acceptable distance within the same watershed or are in adjacent watersheds that possess similar basin characteristics. The use of these "surrogate" watersheds are the most inaccurate account of stream flow and should be used only as approved at the discretion of the Department.

3. All streamflow records used in determining the instantaneous passby flow rates should be measured to the nearest 0.1 cfs at 15-minute increments. Water withdrawal rates must be reported as instantaneous measurements to the nearest 0.1 cfs at 5-minute increments. Reporting is required annually to Department in Microsoft Excel or similar electronic spreadsheet/database formats.

4. Violations and Suspension of Operations. Water withdrawal operations will be suspended immediately upon determination that the required passby flow has not been maintained. The Department has the right to modify passby flow requirements if water quality standards are not being met within a watercourse as the result of a water withdrawal. Failure to submit annual reports, filing of inaccurate reports on water withdrawals, and continuing to withdraw water after a determination that the required passby flow has not been maintained, are all considered separate violations of this permit and the Environmental Conservation Law Article 71-1305(2).

ATTACHMENT C

FOREST AND GRASSLAND FOCUS AREAS

Operators developing well sites in Forest and Grassland Focus Areas that involve disturbance in a contiguous forest patch of 150 acres or more in size or in a contiguous grassland patch of 30 acres or more in size must:

1) Implement mitigation measures identified as part of the Department-approved ecological assessment;

2) Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion; and

3) Practice adaptive management as previously unknown effects are documented.

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Appendix 11

Analysis of Subsurface Mobility of Fracturing Fluids

(Excerpted from ICF International, Task 1, 2009)

Final

Supplemental Generic Environmental Impact Statement

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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:

$$i = \frac{h_{t1} - h_{t2}}{L} \tag{1}$$

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,

$$h_t = h_e + h_p \tag{2}$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \tag{3}$$

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.

$$d_n = -h_{en} \tag{4}$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \tag{5}$$

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

$$h_{p1} = \frac{110\% \times d_1 \times [0.75(150\,pcf - 62.4\,pcf) + 62.4\,pcf]}{62.4\,pcf} = 2.26 d_1 \tag{12}$$

Equation (6) thus becomes

$$i = \frac{(d_2 - d_1) + 2.26 d_1}{|d_1 - d_2|} = \frac{d_2 + 1.26 d_1}{|d_1 - d_2|} \tag{13}$$

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.

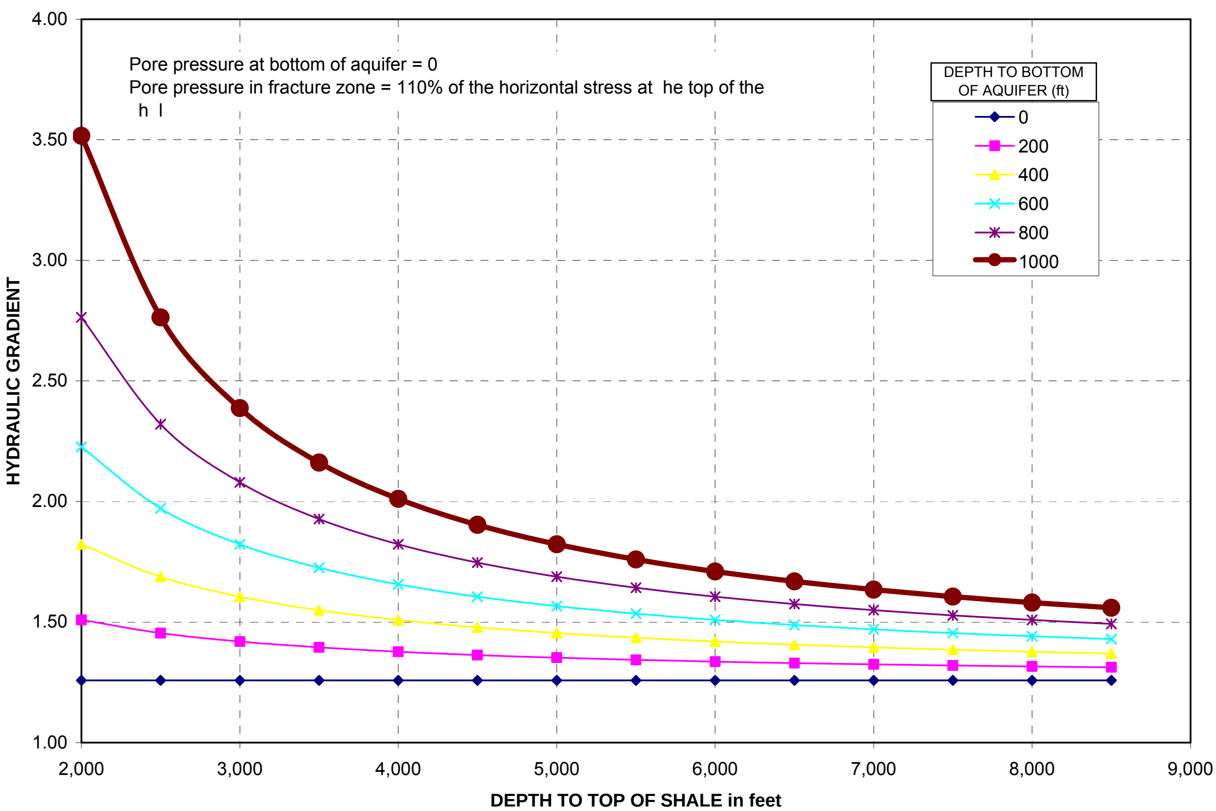

Figure 1: Average hydraulic gradient during fracturing

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.

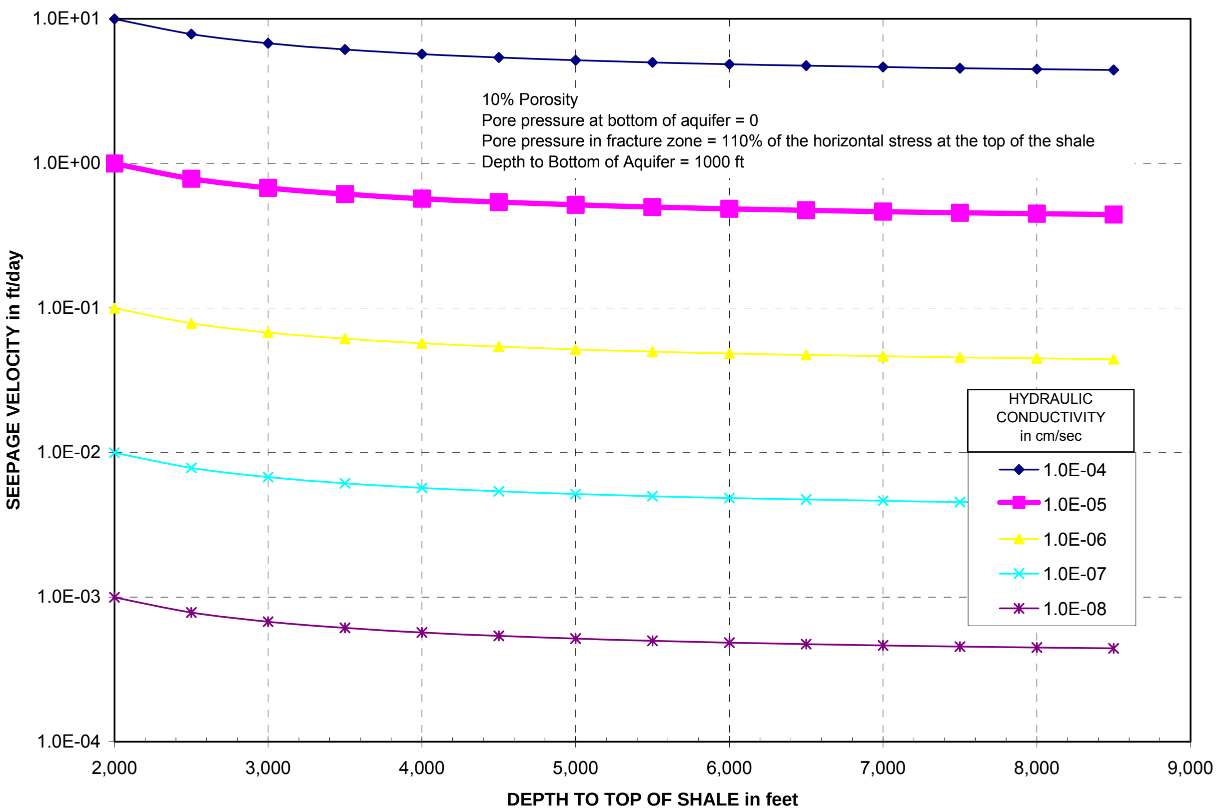

Figure 2: Seepage velocity as a function of hydraulic conductivity

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

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where t = required travel time

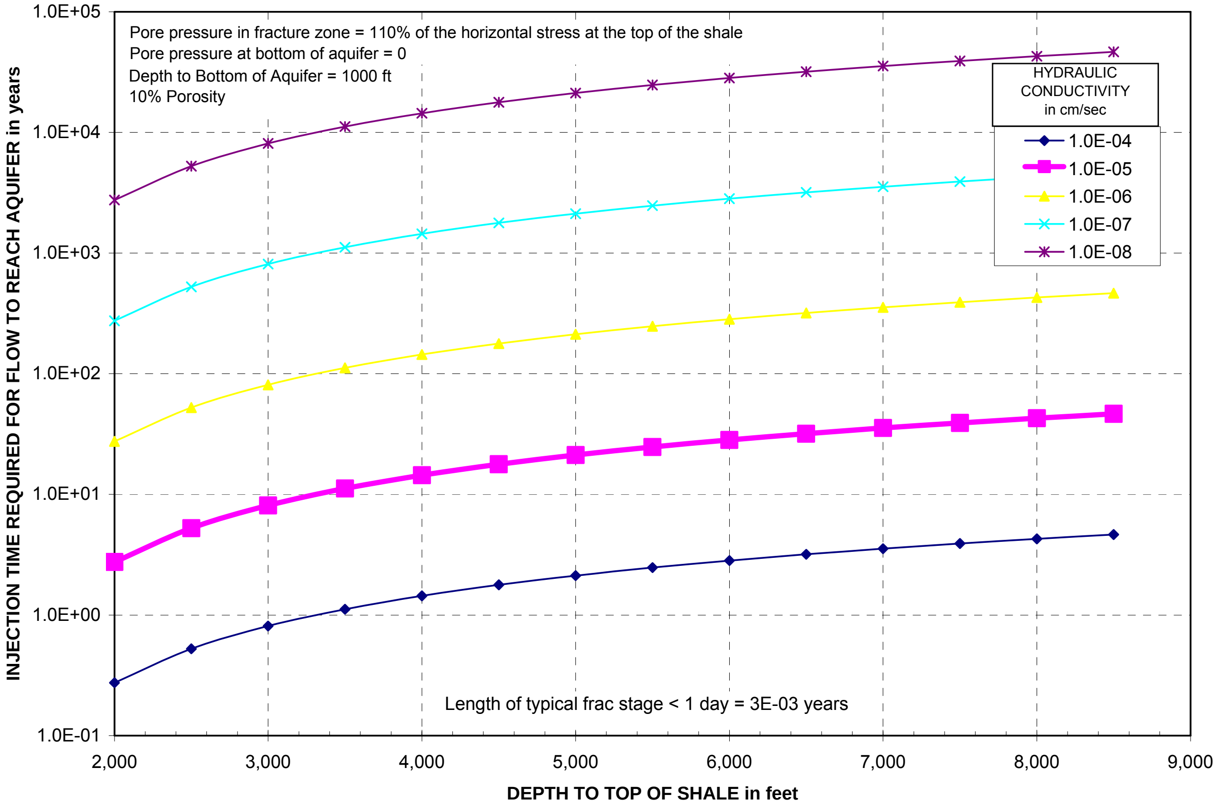

Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity

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.

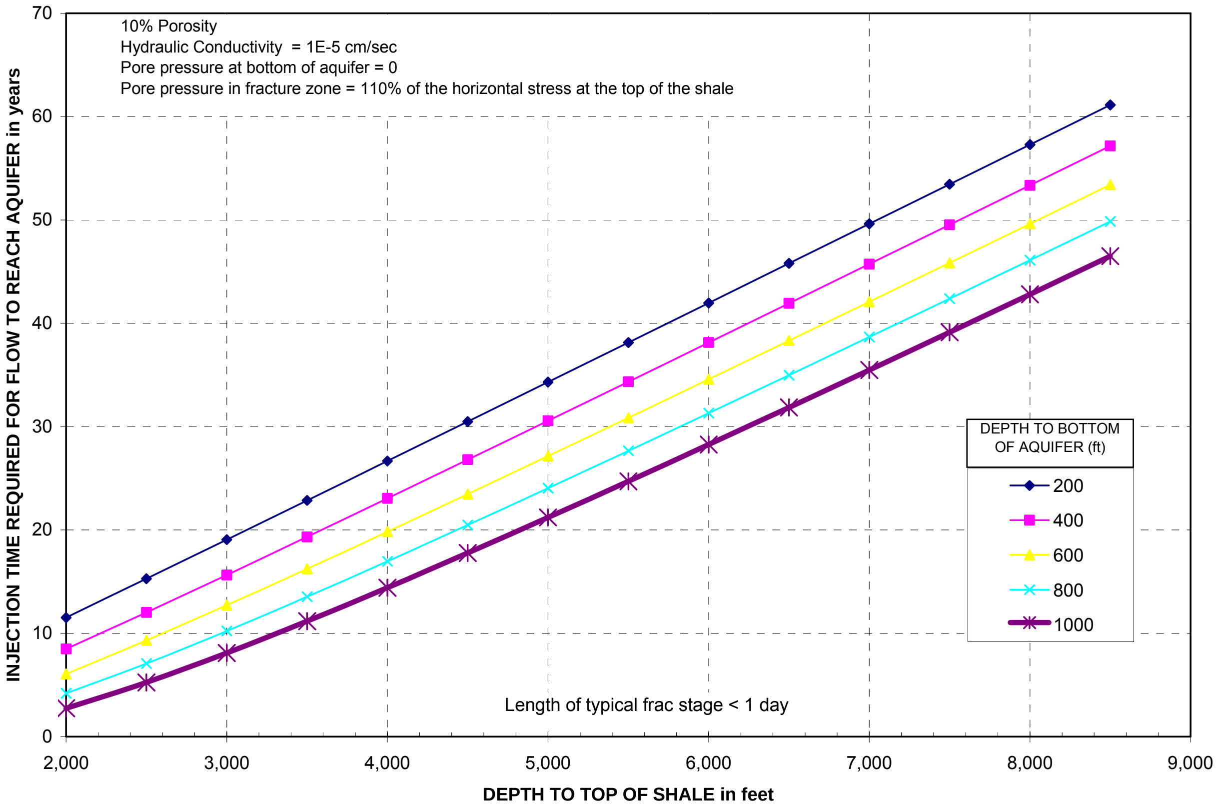

Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth

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.

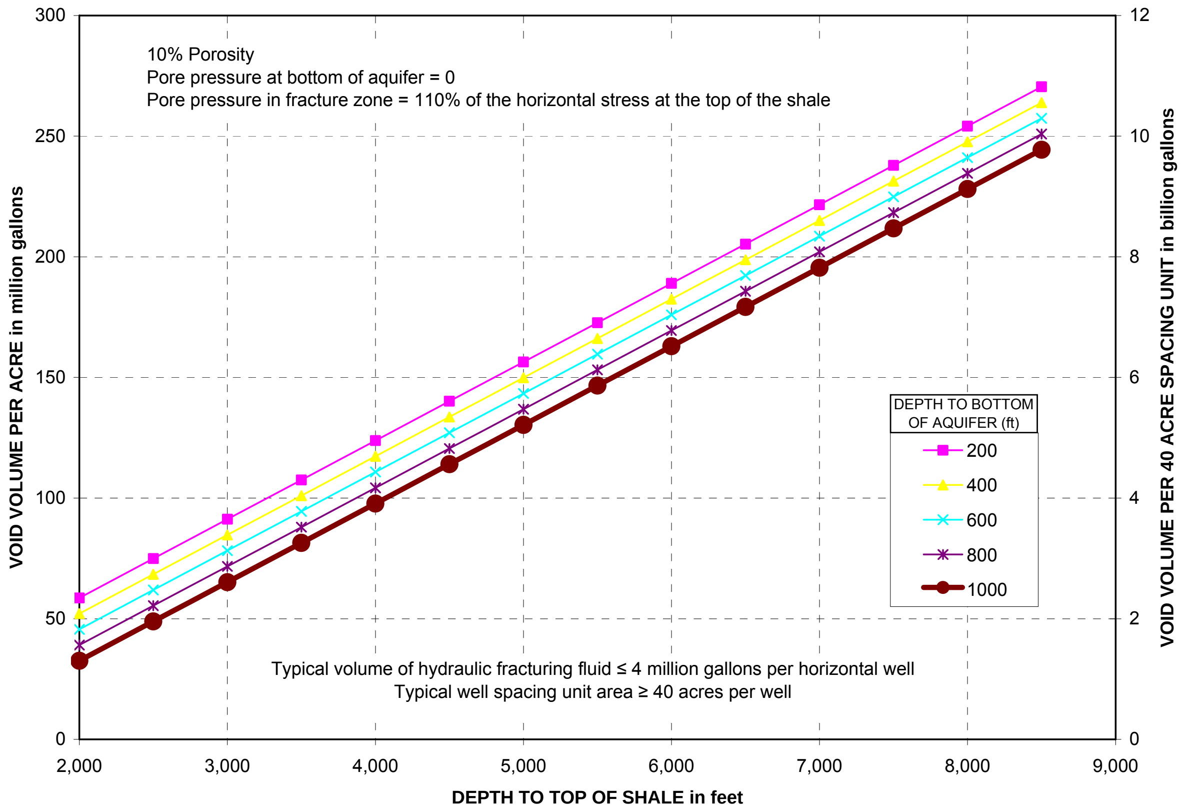

Figure 5: Comparison of void volume to frac fluid volume

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]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \qquad (13)$$

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.

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Appendix 12

Beneficial Use Determination (BUD) Notification Regarding Road Spreading

Final

Supplemental Generic Environmental Impact Statement

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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 OF OPPORTUNITY. | Department of Environmental Conservation

Appendix 13

Radiological Data - Production Brine from NYS Marcellus Wells

Final

Supplemental Generic Environmental Impact Statement

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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 OF OPPORTUNITY | Department of Environmental Conservation

Appendix 14

Department of Public Service Environmental Management and Construction Standards and Practices – Pipelines

Final

Supplemental Generic Environmental Impact Statement

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ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION

STANDARDS AND PRACTICES

CHECK-OFF LIST: PART III

PIPELINE

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Appendix 15

Hydraulic Fracturing – 15 Statements from Regulatory Officials

Final

Supplemental Generic Environmental Impact Statement

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Part A

GWPC's Congressional Testimony

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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:

June 2, 2009 (5:31PM) - non governmental witness

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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.

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

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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

OIL AND GAS BOARD
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S. Marvin Rogers, Counsel

420 Hackberry Lane
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Tuscaloosa, Alabama 35486-6999
Phone (205)349-2852
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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."

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Appendix 16

Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

Final

Supplemental Generic Environmental Impact Statement

Applicability of NO_X RACT Requirements for Natural Gas Production Facilities

New York State's air regulation 6 NYCRR 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_X), applies to boilers (furnaces) and internal combustion engines at major sources.

The requirements of 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 NO_X RACT requirements can limit, or "cap", their emissions using the limits within the New York State Department of Environmental Conservation's (Department) Air Emissions Permits applicability thresholds to avoid this regulation.

New York State has two different major source thresholds for NO_X RACT and permitting. Downstate (in New York City and Nassau, Suffolk, Westchester, Rockland, and Lower Orange Counties) the major source permitting and NO_X RACT requirements apply to facilities with a PTE of 25 tons/yr or more of NO_X. 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 NO_X.

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 NO_X source, the following compliance options are available:

1. Develop a NO_X RACT compliance plan and apply for a Title V permit.

2. Limit the facility's emissions to remain under the NO_X 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 6 NYCRR 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 NO_X emissions cannot be capped below the applicability levels, then the facility should immediately develop a NO_X 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 Department 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.

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Appendix 17

Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities – Final Rule

Final

Supplemental Generic Environmental Impact Statement

Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities – Final Rule

EPA published a final rule on August 20, 2010 revising 40 CFR Part 63, Subpart ZZZZ, in order to address hazardous air pollutant (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 HAPs 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 HAPs 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 HAPs from diesel fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Although numerous HAPs may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAPs are: formaldehyde, acrolein, methanol, and acetaldehyde. EPA is proposing to limit emissions of HAPs through emissions standards for formaldehyde for non-emergency four stroke-cycle rich burn (4SRB) engines 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 provided in the table below.

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.

Subcategory	Emission standards at 15 percent O_2, as applicable, or management practice	
	Except during periods of startup	**During periods of startup**
Non-Emergency 4SLB* >500HP	47 ppmvd CO or 93% CO reduction	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
Non-Emergency 4SLB ≤500HP	Change oil and filter every 1440 hours; inspect spark plugs every 1440 hours; and inspect all hoses and belts every 1440 hours and re-place as necessary.	Same as above
Non-Emergency 4SRB >500HP**	2.7 ppmvd formaldehyde or 76% formaldehyde reduction.	Same as above
Non-Emergency CI >500HP	23 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI* 300-500HP**	49 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI ≤300HP	Change oil and filter every 1000 hours; inspect air cleaner every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Same as above

*4SLB - four stroke-cycle lean burn
**4SRB - four stroke-cycle rich burn
***CI - compression ignition

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Appendix 18

Definition of Stationary Source or Facility for the Determination of Air Permit Requirements

Final

Supplemental Generic Environmental Impact Statement

Definition of Stationary Source or Facility
for the Determination of Air Permit Requirements

Summary

The Department must determine the applicability of air permitting regulations and requirements to natural gas drilling activities in the Marcellus Shale formation. Specifically, the Department must determine applicable regulations and permit requirements for:

- sources subject to stationary source permitting under 6 NYCRR Part 201.
  major stationary source **-** one that emits or has the potential to emit any of the following:
  - 100 tons per year (Tpy) or more of any regulated air pollutant (NO_X, SO_2, CO, PM2.5, PM_{10}); 50 Tpy of VOC.
  - 10 Tpy or more of any individual Hazardous Air Pollutant (HAP); or
  - 25 Tpy or more of any combination of HAPs.

- sources subject to New Source Performance Standards (**NSPS**)

- sources subject to National Emission Standards for Hazardous Air Pollutants (**NESHAP**), and

- 6 NYCRR Part 231 for major new or major modifications to existing sources subject to preconstruction review requirements under Prevention of Significant Deterioration (**PSD**) and/or Non-Attainment New Source Review (**NSR**)

In addition to threshold criteria detailed in regulation and guidance, the Department must evaluate a variety of technical and factual information to assess applicability of these rules to specific sources through the permit application process. These evaluations, as they pertain to natural gas drilling activities in the Marcellus Shale formation, are discussed herein, including 1) whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source for purposes of NSR and Title V programs; and 2) how to assess NESHAP applicability given the unique regulatory definition of "facility" for the oil and gas industry.

Major Stationary Source Determinations for Criteria Pollutants

PSD, NSR and Title V operating permit program (Title V) regulations apply to certain sources with the potential to emit pollutants in excess of the major source thresholds. To assess applicability, the Department must evaluate whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source. The evaluation begins with the federal definition of "stationary source" at 40 CFR 52.21(b)(5) and a similar definition for major source under 6 NYCRR 201-2.1(b)(21). The federal definition reads "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." "Building, structure, facility, or installation" is further defined in 40 CFR 52.21(b)(6):

> *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

To identify pollutant-emitting activity that belongs to the same building, structure, facility, or installation, permitting authorities rely on the following three criteria: 1) whether the activities belong to the same industrial grouping; 2) whether the activities are located on one or more contiguous or adjacent properties; and 3) whether the activities are under the control of the same person (or person under common control).[1] These criteria are applied case-by-case to make the major stationary source determination.

Since the original 1992 GEIS, DEC reviewed numerous source determinations from EPA permitting actions, guidance provided by EPA to inform permitting actions by other permitting authorities, and source determination protocol developed by other states. These documents have been informative. However, EPA has clearly stated that "no single determination can serve as an adequate justification for how to treat any other source determination for pollutant-emitting activities with different fact-specific circumstances."[2] "Therefore, while the prior agency statements and determinations related to oil and gas activities and other similar sources may be instructive, they are not determinative in resolving the source determination issue…, particularly where a state with independent permitting authority is making the determination and the prior agency statements had… substantially different fact-specific circumstances."[3] As such, DEC will formulate case-specific source determinations based on the foregoing, federal and state regulation, evolving case law, industry data and the specific facts of each air permit application. These determinations will be made during the review of permit applications for compressor stations which are associated with Marcellus Shale activities.

The three source determination criteria are discussed in more detail below.

1) **Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group"?** In formulating the definition of "source," EPA uses a Standard Industrial Classification (SIC) code for distinguishing between sets of activities on the basis of their functional interrelationships.[4] Each source is to be classified according to its primary

[1] Memorandum from Gina McCarthy, EPA Assistant Administrator, to Regional Administrators, Sept. 22, 2009, available at http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf
[2] Id.
[3] In The Matter Of Anadarko Petroleum Corporation, Frederick Compressor Station, Order Responding To Petitioners' Request That The Administrator Object To Issuance Of A State Operating Permit, February 2, 2011, Petition Number: VIII-2010-4.
[4] 45 FR 52695, at 31.

activity, which is determined by its principal product or group of products produced or distributed, or services rendered.[5]

The Standard Industrial Classification Manual lists activities associated with oil and gas extraction in Major Group 13 and activities associated with natural gas transmission in Major Group 49. Establishments primarily engaged in operating oil and gas field properties, including wells, are grouped into Major Group 13. The Standard Industrial Classification Manual does not expressly list all equipment, such as midstream compressor stations, in Major Group 13, nor Major Group 49. Therefore, the Department may look to other information, such as federal and state regulations, industry data, and gas gathering agreements, to help make the source determination. For instance, under NESHAP, EPA regulates compressor stations that transport natural gas to a natural gas processing plant[6] in accordance with natural gas production facilities, Major Group 13.[7] In the absence of a natural gas processing plant, EPA regulates a compressor station in accordance with natural gas production facilities where the compressor station is prior to the point of custody transfer.[8] If the compressor station is after the point of custody transfer, EPA regulates the compressor station in accordance with natural gas transmission and storage facilities, Major Group 49. In relevant part, custody transfer means the transfer of natural gas to pipelines *after processing or treatment*.[9]

Where the pollutant-emitting activities do not belong to the same industrial grouping or "Major Group," the Department will ascertain whether one activity serves exclusively as a support facility for the other. In the Preamble to its 1980 PSD regulations, EPA "clarifies that "support facilities" that "convey, store, or otherwise assist in the production of the principal product" should be considered under one source classification, even when the support facility has a different two-digit SIC code.[10]

2**)** **Are the pollutant-emitting activities contiguous or adjacent?** EPA has routinely relied on the plain meaning of the word "contiguous," that is - being in actual contact; touching along a boundary or at a point. However, "the more difficult assessment is determining whether … a non-contiguous [pollutant-emitting activity] might be considered "adjacent."[11] First, EPA has not established a specific distance between activities in assessing whether such activities are adjacent.[12] Second, "the concept of "interdependency," which many individual EPA determinations consider, is not discussed in the 1980 Preamble or mentioned in the federal PSD or Title V regulations defining "source."[13] "[I]nterdependency is a factor that has evolved over time in various case-by-case determinations. While interdependency is a

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5 45 FR 52695, at 32.
6 40 CFR §63.761, *Natural gas processing plant.*
7 40 CFR §63.761, *Facility.*
8 40 CFR §63.760(a)(3)
9 40 CFR §63.761, *Custody transfer.*
10 45 Fed. Reg. 52676 (August 9, 1980)
11 Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 15, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
12 Id.
13 Id. at 14

consideration, it is not an express element of the actual three-part test set forth in regulation, and in the context of oil and gas infrastructure, it may have reduced relevance to an agency determination"[14] Nevertheless, to be thorough, DEC staff will consider the nature of the relationship between the facilities and the degree of interdependence between them.[15] However, interdependence alone may not be dispositive of whether the non-contiguous emissions points should be aggregated in this context.

A "high level of connectedness and interdependence between two activities" is needed to deem them adjacent, and "interdependence requires that the two activities rely on each other – not just that one activity relies on the other activity.[16] Furthermore, "a determination of interdependence requires that the two activities rely upon each other *exclusively*; i.e., one activity cannot operate or occur without the other. The case-by-case determinations indicate that if activities operate independently and one activity does not act solely as a support operation for the other, the activities should not be deemed contiguous or adjacent."[17] In guidance provided by EPA to the Utah Division of Air Quality,[18] EPA recommended using the following indicators as determinative of adjacency for two Utility Trailer Manufacturing Company facilities: 1) whether the location of the new facility was chosen because of its proximity to the existing facility; 2) whether materials would routinely be transferred back and forth between the two facilities; 3) whether managers and other workers would be shared between the two facilities; and 4) whether the production process itself would be split between the two facilities.[19] While DEC will use these and other questions to inform its source determination, some questions may have reduced relevance in the oil and gas industry. For instance, the location of oil and gas activity, proximate or otherwise, may "be controlled by land agreements, access issues, geologic formations, terrain, and, in other situations, by federal or state land management agencies, such as the Bureau of Land Management for oil and gas production on federal lands,"[20] and thus not necessarily indicative of interdependence.

3) **Are the activities under common control?** To assess common control, EPA has historically relied on the Securities and Exchange Commission's definition of control as follows: The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association), whether through the ownership of voting shares, by contract or otherwise. The following questions have been used previously and in more recent actions by EPA to determine

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[14] Id. at 36

[15] Letter from Cheryl Newton, U.S. EPA, to Scott Huber, Summit Petroleum Corporation, October 18, 2010, at 4, http://www.epa.gov/region07/air/title5/t5memos/singler5.pdf

[16] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 21, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[17] Id. at 36 – 37.

[18] Letter from Richard Long of EPA Region VIII to Lynn Menlove of Utah Division of Air Quality, dated May 21, 1998. http://www.epa.gov/region07/air/title5/t5memos/util-trl.pdf

[19] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 20, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[20] Id. at 40

"common control":[21] 1) Whether control has been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation; 2) Whether control has been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity; 3) Whether there is a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract; 4) Whether there is a support or dependency relationship between the two entities such that one would not exist "but for" the other?

Thus, the Department will use answers to the following questions to help guide the case-specific source determinations for natural gas drilling activities in the Marcellus Shale formation that may be subject to NSR and Title V for criteria pollutants.

1. Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group" as described in the Standard Industrial Classification Manual?
    a. What is the primary activity engaged in by the facility?
    b. If the pollutant-emitting activities do not belong to the same industrial grouping or Major Group, does one activity serve exclusively as a support facility for the other?
2. Are the pollutant-emitting activities contiguous or adjacent?
    a. Are the pollutant-emitting activities contiguous? Do they share a boundary or touch each other physically?
    b. If the pollutant-emitting facilities are non-contiguous, are they proximate or interdependent?
    c. Was the location of the new facility chosen because of its proximity to the existing facility?
    d. Will materials routinely be transferred back and forth between the two facilities?
    e. Will managers and other workers be shared between the two facilities?
    f. Will the production process be split between the two facilities?
3. Are the activities under common control?
    a. Has control been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation?
    b. Has control been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity?
    c. Is there a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract?

[21] Letter from Kathleen Henry of EPA Region III to John Slade of Pennsylvania DEP, dated 1/15/99. Also, Letter from Richard Long of EPA Region VIII to Margie Perkins, Air Pollution Control Division, Colorado Department of Public Health Environment, dated October 1, 1999, http://www.epa.gov/region07/air/nsr/nsrmemos/frontran.pdf

d. Is there an exclusive support or dependency relationship between the two entities such that one would not exist "but for" the other?

NESHAPS Applicability for Hazardous Air Pollutants

"[I]n the hazardous air pollutant (HAP) arena, EPA has expressly determined, consistent with Congress' statutory mandate in the [Clean Air Act] CAA, 42 U.S.C. § 7412(n)(4)(A), oil and gas production field facilities are typically not industrial facilities that should be aggregated."[22] The CAA, 42 U.S.C. § 7412, defines "major source" as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants; and "area source" as any stationary source of hazardous air pollutants that is not a major source. Notwithstanding this definition, Section 7412(n)(4)(A) exempts oil and gas wells and pipeline facilities from the requirement to aggregate with contiguous sources under common control when deciding if the source is a major source for NESHAPS applicability.

In the context of hazardous air pollutants, EPA declared that "[s]uch facilities generally are not in close proximity to or co-located with one another (contiguous) and located within an area boundary, the entirety of which (other than roads, railroads, etc.), is under the physical control of the same owner."[23,24] In light of this, EPA developed a unique definition of facility for the oil and gas industry NESHAP regulations (40 CFR 63 Subparts HH and HHH). For HAP major source determinations, the EPA-promulgated definition of "facility" states that "pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts . . . or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility."[25,26] EPA defines a "surface site" at 40 CFR 63.761 of Subpart HH as " Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed".

Accordingly, to determine applicability of the NESHAPs rules governing Oil and Gas Production and Natural Gas Transmission industry sectors, the regulatory definition of facility authorized by CAA, 42 U.S.C. § 7412(n)(4)(A) and found at 40 CFR 63 Subparts HH and HHH, must be used. The Department will follow this definition in determining the regulatory applicability of NESHAPS requirements for HAPS. This opens up the possibility that a "facility" definition for a certain permit application may result in a determination of "major source" for purposes of NSR or Title V permitting, but which will consist of several area source surface sites for the purposes of NESHAP applicability. Guided by EPA's three source determination criteria and the underlying recommendation to use case specific facts, the

[22] Id. at 23
[23] 63 Fed. Reg. 6288, 6303 (Feb. 6, 1998)
[24] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[25] 64 Fed. Reg. 32610, 32630 (June 17, 1999)
[26] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

Department will consider all pertinent information on a case-by-case basis in arriving at its conclusions during source permitting review.

NEW YORK STATE OF OPPORTUNITY. Department of Environmental Conservation

Appendix 18A

Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing Operations

Updated/revised 2015

Final

Supplemental Generic Environmental Impact Statement

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Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing Operations

Nonroad Emissions Standards

Tables 1 and 2 describe the EPA emissions standards for nonroad diesel engines relevant to natural gas well drilling and hydraulic fracturing. These standards are contained in 40 CFR Parts 89 and 1039. These standards may be considered worst case emission levels. Table 1 covers engines rated from 600-750 horsepower. Table 2 covers engines rated at more than 750 horsepower that are not installed in a generator set. Engines are held to these standards for a useful life of the lesser of 8000 hours or 10 years. Actual operating lifetimes are likely much longer.

Table 1. Nonroad Engine Standards for Engines Rated Between 600 and 750 Horsepower

Standard	Initial Year	PM (g/bhp*hr)	NO_X (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	1996	0.4	6.9	1.0	
Tier 2	2002	0.15	4.32	0.48	4.8 g/bhp*hr NO_X + HC standard
Tier 3	2006	0.15	2.7	0.3	3.0 g/bhp*hr NO_X + HC standard
Tier 4 interim	2011	0.01	1.35	0.14	NO_X standard half-way between Tier 3 and Tier 4
Tier 4	2014	0.01	0.3	0.14	

Tier 2 and Tier 3 NO_X and hydrocarbon standards are an additive NO_X plus hydrocarbon (HC) standard. For Tier 2 the limit is 4.8 g/bhp*hr. For Tier 3 the limit is reduced to 3.0 g/bhp*hr. In order to use the standards as conservative emissions limits, it is necessary to apportion the emission limit between the two pollutants. The Tables apportion 90% of the emissions to NO_X and the remaining 10% to hydrocarbons. EPA and European Union (EU) emissions tiers that have separate NO_X and hydrocarbon standards, not requiring exhaust aftertreatment, generally have the NO_X standard equaling 86-88% of the sum of the two standards. It should be noted that data supplied on behalf of industry (1) assumed that 100% of these emissions are NO_X, which is deemed conservative.

There is no official “Tier 4 interim” standard for engines in the Table 1 horsepower class. Beginning in 2011, 50% of the engines in the class are supposed to meet the Tier 4 NO_X standards. This would increase to 100% in 2014. When faced with the exact same phase-in schedule from 2007-2010 for highway diesel engines, manufacturers universally chose to initially certify all engines to a Family Emissions Level half way between the old standard and the new standard, and postpone the NO_X aftertreatment requirements for three years. Thus, the NO_X emissions level of 1.35 g/bhp*hr in the Table is the average of the Tier 3 and Tier 4 standards.

Table 2. Nonroad Engine Standards for Engines Rated Above 750 Horsepower (Updated 2012)

Standard	Initial Year	PM (g/bhp*hr)	NO_X (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	2000	0.4	6.9	1.0	
Tier 2	2006	0.15	4.32	0.48	4.8 g/bhp*hr NO_X + HC standard
Tier 4 interim	2011	0.075	2.6	0.3	
Tier 4 final	2015	0.03	2.6	0.14	
Tier 4 final	2015	0.02	0.5	0.14	Generator sets only

Tier 1 and Tier 2 standards for engines rated above 750 horsepower are the same as the corresponding standards for engines rated between 600 and 750 horsepower. Again, the Tier 2 NO_X plus hydrocarbon standard is apportioned 90% NO_X and 10% hydrocarbon. There are no Tier 3 standards for these engines. The Tier 4 interim standards are promulgated standards. Also, the Tier 4 standards for engines rated above 750 horsepower not installed in generator sets may not force the use of NO_X aftertreatment, although at least one manufacturer reportedly intends to use SCR on these engines by 2015 (2).

Final Tier 4 standards for generator sets rated above 750 hp are significantly more stringent than the corresponding standards for other engines. Some drilling rigs are designed with electric motors to drive various pieces of equipment rather than mechanical or hydraulic drives. Electric drive pumps for hydraulic fracturing may also be possible. The use of electric drive equipment would allow the use of lower emission diesel engines in the future, as well as the possibility of the use of grid electricity where sufficient electrical power is available.

Retrofit of Exhaust Aftertreatment

Prior to Tier 4, none of the new engine standards were stringent enough to require exhaust aftertreatment. Current highway engine standards require aftertreatment to meet both the PM and NO_X standards. Furthermore, there is now substantial experience with retrofitting exhaust aftertreatment to highway engines and stationary engines. Particulate matter control technologies include: Diesel Oxidation Catalysts (DOC) which oxidize hydrocarbons and carbon based particulate matter, and particulate filters or "traps" where particulate matter is collected and oxidized. Where exhaust conditions are suitable Continuously Regenerating Diesel Particulate Filters (CRDPF) are common. In other cases, particularly when exhaust temperatures are too low, active traps may be used. Active traps use an external energy supply (usually electricity or a secondary fuel burner) to oxidize particulate matter rather than relying solely on exhaust heat. Active trap retrofits may require more complex control systems.

NO_X control technologies include: Selective Catalytic Reduction (SCR) which uses ammonia (usually supplied as urea), Lean NO_X Catalysts, or Lean NO_X Traps (also referred to as "NO_X absorbers") to reduce NO_X emissions. Although in the past EPA had identified the Lean NO_X Traps as a promising technology, it has not been applied to the size class of the drilling and hydraulic fracturing engines. In addition, the lean NO_X Catalyst system's NO_X reduction would be insufficient to meet the ultimate engine standards. Thus, for NO_X control, the SCR system is recommended.

Table 3 lists the aftertreatment effectiveness claimed by one manufacturer, Johnson Matthey,[1] as an example for retrofit installations on stationary engines (3).

Table 3. Exhaust Aftertreatment Retrofit Effectiveness

Technology	Abbreviation	PM Emissions Reduction (%)	NO_X Emissions Reduction (%)	HC Emissions Reduction (%)
Diesel Oxidation Catalyst	DOC	30%	0	90%
Particulate Trap	CRDPF	85%	0	90%
Particulate Trap and SCR	SCR-DPF (SCRT)	85%	90%	90%

Johnson Matthey has EPA certification of its SCR-DPF system (referred to as SCRT) as a verified retrofit for some classes of highway diesel engines. That verification is for a 70% NO_X emissions reduction (4). The development of Johnson Matthey's retrofit system is described by Conway and coworkers (5). This certification does not negate the 90% reduction expected for these nonroad engines due to factors discussed below.

The SCR and CRDPF technologies are the dominant technologies used to meet the current highway emissions standards, and are expected to dominate the exhaust aftertreatment market for many large nonroad diesel engine classes. There are other NO_X control technologies; however their applicability appears to be limited to smaller engines, such as those in light duty vehicles.

Feasibility of Exhaust Aftertreatment

As discussed above, SCR and CRDPF technologies are widely used to control NO_X and PM emissions from diesel cycle internal combustion engines, including engines both larger and smaller than well drilling and hydraulic fracturing engines. These technologies are used both on new engines and as retrofits to existing engines.

No exhaust aftertreatment retrofits for these engines and duty cycles have been verified by EPA or the California Air Resources Board (CARB). Both verification programs are voluntary. The primary purpose of the EPA verification program is to verify eligibility for federal diesel emission reduction retrofit grants. The primary purpose of the CARB program is to verify emissions reductions for use by engine owners in complying with California's Airborne Toxic Control Measures for diesel particulate matter. To the Department's knowledge no exhaust retrofits for the gas well drilling rig and hydraulic fracturing engines expected to be used in developing the Marcellus Shale formation in New York have been submitted to either verification program.

[1] Listing of this manufacturer does not imply any form of endorsement. Other manufacturers could provide similar aftertreatment information.

Lack of verification does not necessarily preclude commercial application of a retrofit. However, verification, which requires significant work by the applicant, does provide benefits to all parties. Verification provides assurances regarding the level of emissions control, and assurance that the control equipment will continue to be effective over a period of time. The verification programs also impose warranty requirements.

The intended duty cycle of the engine is an important factor in the design of emissions control systems. Particularly critical for CRDPF installations is the exhaust temperature. Exhaust temperature must be high enough, frequently enough, to oxidize accumulated particulate matter. Failure to regenerate the particulate trap can lead to engine damage. The exhaust temperatures reported on behalf of industry (800-900 °F) (1) are high enough to support aftertreatment retrofits which require minimum temperatures of roughly 250 °C (<500 °F) (4) (5). The fraction of time when exhaust temperatures are at the industry reported temperatures is not known. The frequency and duration of events where the exhaust temperature would be below minimum requirements is also unknown, and important to the feasibility of the exhaust aftertreatment.

Physical configuration also places constraints on exhaust aftertreatment design. CRDPFs in particular are significantly larger than typical exhaust system components. Exhaust aftertreatment must be located near the engine to maximize the use of available exhaust heat. However, the exhaust system cannot interfere with the safe use of the equipment. This may be less of a problem for drilling rigs and hydraulic fracturing equipment than for mobile machinery since they are physically static during drilling or hydraulic fracturing. Physical configuration issues are more difficult to address when retrofitting existing equipment than when designing new equipment.

In the event that CRDPFs are not feasible for a specific application, DOCs may provide a feasible intermediate level of control. Exhaust aftertreatment consisting of SCR and DOCs has been retrofitted to Caterpillar 3512 generator set engines used on drill rigs in Wyoming (6).

Emissions of Nitrogen Dioxide

Nitrogen Dioxide (NO_2) is not explicitly regulated via EPA engine emissions standards. It is a component of the regulated pollutant NO_X. However, primary NO_2 emissions are a concern in the Marcellus Shale evaluation since for the evaluation of the new 1 hour NO_2 standard, specific emission factor estimates are necessary to assure that modeling results account for the NO_2 portion of the emissions.

Conventional information indicates that roughly 5% of NO_X emissions from internal combustion engines are NO_2; the balance are NO. However, European researchers have noted that ambient NO_2 concentrations have not been declining despite declining NO_X emissions from engines and vehicles. This has led to some investigation of the NO_2 fraction of primary NO_X emissions from highway vehicles. The most comprehensive summary is by Grice, et al (7), who needed the data for model inputs. These researchers found that the conventional use of 5% NO_2 holds for gasoline engines. The NO_2 fraction for diesel engines varies for different emissions control technologies, but is always greater than 5%. The data are summarized based on European emissions standards which must be translated into aftertreatment technology level.

NO_2 fractions for diesels range between 10% and 55% (7). EURO II engines, which have no exhaust aftertreatment, have an NO_2 fraction of 11%. This NO_2 fraction is used for Tier 1, Tier 2, and Tier3 engines with no retrofitted aftertreatment. For particulate trap equipped EURO III engines the NO_2 fraction is 35%. This NO_2 fraction is used for cases with either a DOC or a CRDPF either standard or retrofitted. The oxidation reactions in DOCs oxidize some NO to NO_2 along with the desired oxidation of hydrocarbons and particulate carbon. Indeed, oxidation catalysts are placed ahead of CRDPFs to produce NO_2 for use in oxidizing particulate matter to regenerate the PM trap. NO_2 oxidizes carbon at a lower temperature than O_2.

Finally, Grice et. al. chose to use a NO_2 fraction of 10% for engines equipped with SCR (EURO IV and later). However, the data for the SCR equipped engines was particularly sparse. This uncertainty is discussed further below.

For light duty vehicles equipped with NO_X aftertreatment an NO_2 fraction of 55% was reported. Light duty vehicle NO_X control generally avoids SCR, with its requirement that the operator maintain the urea supply. These alternative NO_X aftertreatment technologies have not proven viable for heavy duty truck engines, never mind the even larger engines to be used in Marcellus Shale drilling and hydraulic fracturing. Thus the 55% NO_2 fraction does not have any applicability here.

Table 4 below summarizes the recommended NO_2 fractions.

Table 4. NO_2 Emissions as Fraction of NO_X Emissions

Technology	**Fraction NO_2 (in %)**
No Exhaust Aftertreatment	11
Diesel Oxidation Catalyst or Particulate Trap	35
SCR (with or without DOC or CRDPF)	10 (see text)

Specifying a single NO_2 fraction for an engine technology is clearly a simplification. Researchers have documented variation in the NO_2 fraction depending on engine load (8) and exhaust temperature (9). The NO_2 fractions in Table 4 for engines without SCR could be low for engines operated at low loads and low exhaust temperatures. They appear to better reflect the emissions at higher loads more in line with the operations expected during drilling and hydraulic fracturing.

Given the particularly high level of uncertainty regarding the NO_2 fraction when SCR is used, a review of the chemistry involved might help. SCR generally converts NO_X to N_2. There are several different reactions involved (10), (11), (12). One of these reactions, the "fast" SCR reaction, is much faster (and has lower minimum temperature requirements) than the others.

$$2NH_3 + NO + NO_2 \rightarrow 2N_2 + 3H_2O$$

The fast SCR reaction generally goes to completion before any of the other reactions become significant. This leads to a desire to have a NO_2 fraction near 50% at the SCR reactor inlet.

However, given variations in the NO_2 consumption by a CRT and variations in engine load and engine out exhaust gas composition, consistently providing the SCR reactor with a 50:50 NO_2 to NO ratio would be quite difficult.

As long as the exhaust gases remain in the SCR reactor after the fast SCR reaction has exhausted one of the NO_X species, other chemical reactions will continue to reduce NO_X. The reaction for NO produces nitrogen and water. Several competing reactions are possible for NO_2. Some of these produce ammonium nitrate or nitrous oxide in addition to nitrogen.

Another concern with SCR is "ammonia slip," the emission of ammonia injected into the exhaust stream but not consumed. Oxidation catalysts are employed after SCR reactors to oxidize ammonia to nitrogen. This catalyst could also oxidize NO to NO_2. Thus, it cannot be completely ruled out that NO_X emissions from SCR equipped engines may consist of more than 10% NO_2, possibly with an upper bound of 35%. However, further review of the literature regarding the chemistry of ammonia slip catalysts leads to the conclusion that oxidation of NO to NO_2 is not a major concern. The desired reaction in the ammonia slip catalyst is the oxidation of ammonia to nitrogen and water. Competing reactions form NO and N_2O, but not NO_2 (13). The fate of NO in an ammonia slip catalyst is to react with ammonia and form N_2O. NO_2 production would likely only begin if the ammonia was exhausted. The chemical reaction mechanism of ammonia oxidation is well known, it is an intermediate step in the industrial production of nitric acid (14). Given that there is no apparent path to NO_2 formation as long as NH_3 is present, greater confidence can be placed in a NO_2 emission estimate of 10% of NO_X for SCR equipped engines.

Thus, actual data summarized by Grice et. al., although sparse, currently suggests that we consider the DOC/CRDPF NO_2 fraction of 10% as the appropriate factor. Regardless of the actual NO_2 fraction of the NO_X emissions from a SCR equipped engine (retrofitted or standard), SCR will provide the lowest NO_2 and NO_X emissions achievable with diesel engines.

Emission Rates for Various Emissions Standards Tiers & Exhaust Aftertreatment Retrofit Options

Considering the different Tiers of engine standards, the variety of possible exhaust aftertreatment retrofits, and the uncertainty in the NO_2 fraction of NO_X emissions from SCR equipped engines, there are in excess of 20 different emissions cases possible. Calculations were performed by Barnes (15) (16), but only the pertinent part of these results are presented in Tables 5 and 6.

These emissions rates are estimated from the relevant U.S. EPA standards presented in Tables 1 and 2. In cases where a NO_X + HC standard was promulgated, the standard is apportioned 90% NO_X, 10% HC. Effectiveness of exhaust aftertreatment retrofits are based on Table 3. Where the claimed retrofit effectiveness reduces an emission rate below a subsequent standard expected to require the same exhaust aftertreatment technology, the subsequent standard (the higher number) is used as the emissions rate. NO_2 emission rates are calculated from NO_X emission rates using factors presented in Table Four. For SCR-equipped engines the NO_2 fraction of 10 % of the NO_X emissions is presented. Note that for Tier 4 engines above 750 hp a case where SCR is standard (and thus cannot be retrofitted) is presented in addition to the original assumption that SCR would not be utilized to meet the 2.6 g/bhp*hr NO_X standard.

Table 5. Emissions Factors for Engines between 600 and 750 Horsepower

Air Drilling Engines

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NO_X (g/bhp*hr)	HC (g/bhp*hr)	NO_2 (g/bhp*hr)
Tier 1	1996	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2002	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 3	2006	None	0.15	2.7	0.3	0.297
		DOC	0.105	2.7	0.14	0.945
		CRDPF	0.03	2.7	0.14	0.945
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2011	None	0.01	1.35	0.14	0.473
		SCR	0.01	0.3	0.14	0.03
Tier 4	2014	None	0.01	0.3	0.14	0.03

Table 6. Emissions Factors for Engines Greater than 750 Horsepower

Drilling Rig and Hydraulic Fracturing Engines (Updated 2012)

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NO_X (g/bhp*hr)	HC (g/bhp*hr)	NO_2 (g/bhp*hr)
Tier 1	2000	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2006	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 4 interim	2011	None	0.075	2.6	0.3	0.91
		CRDPF	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2015	None	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4 SCR Standard		None	0.03	2.6	0.14	0.26
Tier 4 Generator Set		None	0.02	0.5	0.14	0.05

Natural Gas Engines

For the most part, industry uses diesel engines for oil and gas drilling and hydraulic fracturing operations. Natural gas fired engines have been used in some instances. Natural gas engines must either be spark-ignition or a pilot fuel (generally diesel fuel) is necessary to initiate compression ignition (17). The latter are referred to as “dual-fueled.”

Large nonroad spark-ignition engines are certified under 40 CFR Part 1048. Since 2007 these engines have been certified to Tier 2 standards. Note that this is not the same Tier 2 as the nonroad compression-ignition standards referenced in Tables 1 and 2 above. Manufacturers have a choice of six different NO_X + HC standards, depending on the choice of carbon monoxide standard. In keeping with the methodology used above for diesel engines, the most lenient NO_X + HC standards serve as the basis for conservative emission factors.

The only relevant standard is the NO_X + HC standard. Additional information is necessary to derive, NO_X, PM, hydrocarbon, and NO_2 emission factors. This is provided by data published by the National Renewable Energy Laboratory regarding comparative testing of natural gas fueled trucks and buses versus comparable diesel fueled vehicles (18) (19). These limited data suggest that approximately 95% of the total NO_X and nonmethane hydrocarbon (the hydrocarbon measure specified in Part 1048 for natural gas fueled engines) is NO_X. NO_2 emissions are approximately 17% of total NO_X emissions. In the absence of PM standards the most stringent diesel PM standard from Table 2 is used. In the bus testing referenced in (19) the natural gas buses had PM emissions comparable to particulate trap equipped diesels. Emission factors for natural gas fueled spark-ignition engines are summarized in Table 7.

Table 7. Emission Factors for Natural Gas Fueled Spark-Ignition Engines (New 2012)

Standard	Effective Year	PM (g/bhp*hr)	NO_X (g/bhp*hr)	HC (g/bhp*hr)	NO_2 (g/bhp*hr)
Tier 2	2007	0.03	1.9	0.1	0.32

Duel fueled compression-ignition engines would be certified to the same standards as diesel engines of the same model year and horsepower class. They also can be operated solely on diesel fuel. Consequently emission factors derived for diesel engines would apply equally to duel fueled engines.

Summary

Between 2000 and 2015 nonroad engines will have gone through four or five (depending on engine power) different sets of emissions standards. PM mass reduction over this timeframe will be 93% for the largest engines and 98% for engines rated between 600 and 750 horsepower. NO_X emissions will be reduced 96% for the 600 to 750 horsepower engines, but only 62% for the larger engines. Much of these emissions reductions can be achieved without premature replacement of older engines by retrofitting exhaust aftertreatment to these engines. However, successful retrofits are dependent on the details of the engines and duty cycles involved, and have not been verified for drilling and hydraulic fracturing engines. An additional consideration with these retrofits is that PM aftertreatment in the absence of SCR will increase NO_2 emissions.

This concern also applies to current and future Tier 4 engines which may have PM aftertreatment but not NO_X aftertreatment.

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Appendix 18B

Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts By Selected Catalytic Reduction (SCR) Treatment

Updated/revised 2015

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Supplemental Generic Environmental Impact Statement

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Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selective Catalytic Reduction (SCR) Treatment

1. Introduction

Equipping fracturing engines with post-combustion NO_X control equipment could be a potential option for mitigating the modeled exceedances of the 1 hour NO_2 National Ambient Air Quality Standard. Selective Catalytic Reduction (SCR) is a proven technology for reducing oxides of nitrogen (NO_X) emissions from mobile and stationary combustion sources. Although SCR systems have not been applied to fracturing engines, it may be possible to adapt the technology to this class of engines. This technology involves the use of a urea solution (32.5 percent urea) which converts NO_X to nitrogen gas via a catalyst.

An estimate of the mitigation costs based on costs for stationary engines[1] is presented in this appendix. The purpose of these estimates is to determine the cost per ton of NO_X removal for a relative comparison to cost thresholds used by the Department for NO_X RACT purposes at stationary sources.[2] Any reference to specific manufacturers (in footnotes) does not constitute an endorsement, but merely presents the specific information source.

The remainder of this appendix is divided into three sections. First, an estimate is developed regarding how many jobs and how many hours a hydraulic fracturing engine could be used each year in Section 2. In the third section of the appendix, the costs of installing and operating a SCR system on a typical 2250 hp hydraulic fracturing engine are presented. In the fourth section, an estimate of the cost per ton of NO_X removed from the exhaust stream is presented for each engine tier.

2. Operation of Hydraulic Fracturing Engines

According to ALL Consulting, hydraulic fracturing engines will be used at any given well pad for no more than 14 days. Mobilization and de-mobilization activities are expected to take a total of four days. Hydraulic fracturing activities are expected to take ten days per well pad (five days per well).[3] At most, a hydraulic fracturing engine could be used for 26 jobs per year. Allowing for additional travel time, maintenance and vacations, the Department is assuming an engine will be used for approximately 20 jobs per year in the Marcellus play. Further, it was assumed that these engines will be used for a maximum of five hydraulic fracturing events per day and will operate two hours per event at their maximum loading and emissions.[4] Therefore, a hydraulic fracturing engine could be used up to 2,000 hours per year at the maximum load:

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[1] Hydraulic fracturing engines are considered nonroad sources.
[2] See: http://www.dec.ny.gov/regs/4217.html
[3] "NY DEC SGEIS Information Requests", ALL Consulting, September 16, 2010, page 39.
[4] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, page 9.

(20 jobs/year)(10 days/job)(5 hydraulic fracturing events/day)(2 hours/hydraulic fracturing event) = 2,000 hours/year

3. Reduction of Oxides of Nitrogen and Costs

Selective catalytic reduction (SCR) is a proven technology for reducing NO_X emissions. The Department is assuming that this technology is the most likely post-combustion control that could potentially be used to reduce NO_X emissions from hydraulic fracturing engines (see Appendix 20). The Department considered capital, periodic and annual costs in the cost estimates discussed in this section.

Capital Costs

The capital cost for a SCR system was assumed to be $80 per hp.[5] Installation costs were assumed to be 60 percent of the system cost.[6] Taxes were assumed to be eight (8) percent of the system cost. The estimated capital cost for a typical 2250 hp hydraulic fracturing engine is $302,400 as detailed below:

System Cost:	$180,000
Installation:	$108,000
Taxes:	$ 14,400
Total:	$302,400

Periodic Costs

The periodic costs considered by the Department were for replacing SCR catalysts every five years.[7] It was assumed that the replacement costs were seven (7) percent of the system costs[8] and installation 60 percent of the replacement cost. The periodic costs (at year 5) were estimated to be $20,160 as detailed below:

Catalyst Replacement:	$12,600
Installation:	$ 7,560
Total:	$20,160

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5 CARB 2010. Regulatory Analysis for Revisions to Stationary Diesel Engine Air Toxic Control Measure. Appendix B. Analysis of Technical Feasibility and Costs of Aftertreatment Controls on Emergency Diesel Engines.

6 Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, pages 168-169.

7 E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008.

8 E-mail from Chad Whiteman (Institute of Clean Air Companies) to John Barnes dated November 27, 2007 and e-mail from Wilson Chu (Johnson-Matthey) to John Barnes dated January 24, 2008.

Annual Costs

The quantity of reagent used depends upon the amount of NO_X coming from the engine. The control efficiency for SCRs was assumed to be 90 percent for engines. The emission rates factored into this analysis are presented in Table 1 (see Appendix 20). Further, it was assumed that hydraulic fracturing engines will be operated at 50 percent of capacity.[9] The urea requirement for each pound of NO_X treated in an SCR is 0.2088 gallons.[10]

Table 1: NO_X Emission Rates for Tier 2, Interim 4 (I4) and 4 Hydraulic Fracturing Engines

Tier #	NO_X (without control)[11] (g/bhp-h)	NO_X (with control) g/bhp-h
2	4.32	0.43
Interim 4 (I4)	2.60	0.26
4	2.60	0.26

The urea requirements range from 1.21 gallons per hour (gal/h) for a Tier 4 engine to 2.01 gal/h for a Tier 2 engine. The estimated cost of urea is $3.67 per gallon.[12]

In addition to the reagent requirements, annual insurance costs were estimated to be one (1) percent of the system cost[13] and maintenance costs were assumed to be six (6) percent of the system cost.[14] A summary of the annual costs is presented below:

	Tier 2	Tier I4	Tier 4
Reagent:	$14,800	$ 8,900	$ 8,900
Insurance:	$ 3,000	$ 3,000	$ 3,000
Maintenance:	$18,100	$18,100	$18,100
Total:	$35,900	$30,000	$30,000

Annualized Cost

A discount rate of seven (7) percent was used to convert the above costs into an equivalent annual cost for a 10-year horizon. The estimated annualized costs are presented in the next section.

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9 "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, p. 10.
10 E-mail from Michael Baran (Johnson Matthey) to John Barnes, April 17, 2008.
11 See Appendix 20. The values in the second column of Table 1 are assumed to be the NO_x emissions in the exhaust gas coming from the engine chamber.
12 E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008. Also factored was Consumer Price Index data: www.bls.gov/cpi/cpid0801.pdf and www.bls.gov/cpi/cpid0211.pdf.
13 Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, page 202.
14 Ibid, page 200.

4. Cost Effectiveness Analysis

The cost effectiveness (cost per ton of NO_X treated) of applying SCR controls on Tier 2, I4 and 4 hydraulic fracturing engines is presented in Table 2. .Hydraulic fracturing engines equipped with SCRs will have emission rates ranging from 0.26 g/bhp-h (Tier 4) to 0.43 g/bhp-h (Tier 2). The estimated cost per ton of NO_X control is greater than the Department's $5,000 per ton threshold for NO_X RACT (Reasonably Available Control Technology – Subpart 227-2) used to determine cost-effectiveness of controls at major stationary sources.

Table 2: Cost Effectiveness of SCR Control on Hydraulic Fracturing Engines

Engine Tier	Annualized Cost	NO_X Removed (tons)	Cost Effectiveness (ton^{-1})
2	$81,050	9.64	$ 8,400
I4	$75,170	5.80	$12,950
4	$75,170	5.80	$12,950

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Appendix 18C

Regional On-Road Mobile Source Emission Estimates from EPA's MOVES Model and Single-Pad PM2.5 Estimates from MOBILE 6 Model

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2007 Annual Mobile Source Emissions
MOVES 2010a Based Inventory Runs

Includes all MOVES Emission Processes Except Evap. Permeation, Evap. Vapor Venting & Evap. Fuel Leaks

		Base Emissions						Emissions resulting from additonal VMT from proposed drilling activity					
FIPS	County	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
		(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
36001	ALBANY	8423.0	3323.7	64.2	356.3	339.0	51044.0	8447.2	3326.2	64.3	357.6	340.2	51067.1
36003	ALLEGANY	1436.5	495.0	8.5	63.8	60.9	7205.9	1458.5	497.1	8.6	64.8	61.9	7227.5
36007	BROOME	4807.1	1998.9	36.2	209.0	198.5	30424.5	4830.2	2001.2	36.3	210.2	199.6	30447.8
36009	CATTARUAGUS	2446.6	839.0	15.0	107.9	103.0	12115.4	2468.7	841.2	15.0	108.9	104.0	12137.9
36011	CAYUGA	2020.5	774.2	13.6	84.0	80.2	11210.1	2043.2	776.5	13.7	85.2	81.3	11231.9
36013	CHAUTAQUA	4178.1	1410.3	26.5	184.6	176.3	20379.8	4200.5	1412.5	26.6	185.7	177.3	20402.2
36015	CHEMING	2113.2	861.3	15.1	89.3	85.2	12366.7	2137.1	863.8	15.1	90.5	86.4	12390.9
36017	CHENANGO	1066.9	510.5	7.9	43.8	41.5	7513.7	1089.4	512.8	7.9	44.9	42.6	7535.9
36023	CORTLAND	1653.3	543.1	11.1	71.8	68.5	8158.8	1675.5	545.3	11.1	72.9	69.6	8180.9
36025	DELAWARE	1224.2	539.2	9.0	50.1	47.5	8013.5	1246.3	541.3	9.1	51.1	48.6	8034.7
36029	ERIE	19260.0	7997.4	138.2	798.8	760.4	117094.0	19282.6	7999.7	138.3	799.9	761.5	117116.0
36037	GENESEE	3035.1	855.2	20.5	127.1	121.5	13116.7	3057.1	857.4	20.6	128.2	122.6	13138.1
36039	GREENE	1997.6	672.1	14.1	83.1	79.3	10151.8	2020.1	674.4	14.2	84.2	80.4	10174.1
36051	LIVINGSTON	1911.9	683.9	12.3	83.5	79.6	10006.3	1934.2	686.1	12.4	84.6	80.7	10028.8
36053	MADISON	1797.8	729.6	13.1	73.4	69.9	10881.9	1820.3	731.8	13.2	74.6	71.0	10903.7
36065	ONEIDA	4997.0	2222.6	38.1	211.2	200.7	32376.2	5020.6	2225.1	38.1	212.4	201.8	32399.3
36067	ONONDAGA	11468.5	4535.9	82.3	501.2	477.7	66575.9	11492.9	4538.4	82.4	502.4	479.0	66600.0
36069	ONTARIO	3628.0	1241.3	25.5	150.8	144.0	18507.6	3650.8	1243.7	25.6	152.0	145.1	18529.9
36071	ORANGE	7527.5	3123.6	49.7	302.3	286.3	53982.4	7551.6	3126.0	49.8	303.6	287.5	54005.2
36077	OTSEGO	1620.0	640.5	11.4	70.1	66.6	9659.1	1641.8	642.6	11.5	71.1	67.6	9681.4
36095	SCHOHARIE	1505.6	496.2	11.6	62.0	59.0	7964.9	1527.7	498.4	11.7	63.1	60.1	7987.0
36097	SCHUYLER	558.3	215.0	3.8	22.8	21.7	3102.1	580.9	217.4	3.9	23.9	22.9	3122.9
36099	SENECA	1234.1	401.9	8.3	52.1	49.8	5979.4	1256.6	404.2	8.4	53.2	50.8	6002.1
36101	STEUBEN	3969.5	1197.4	24.2	173.8	166.3	17845.0	3991.3	1199.5	24.3	174.9	167.3	17867.0
36105	SULLIVAN	1481.6	752.4	11.8	58.4	55.3	11050.7	1504.9	754.7	11.9	59.6	56.5	11070.8
36107	TIOGA	1398.8	599.9	10.5	57.6	54.9	8538.5	1423.3	602.6	10.6	58.9	56.2	8561.8
36109	TOMPKINS	1727.3	790.5	12.8	72.3	68.8	11227.7	1751.6	793.1	12.9	73.5	70.1	11250.9
36111	ULSTER	4114.3	1895.8	36.0	156.2	148.2	29231.2	4138.3	1898.4	36.1	157.5	149.4	29254.8
36121	WYOMING	999.9	414.6	6.5	42.3	40.4	5827.2	1022.8	416.9	6.6	43.5	41.5	5847.9
36123	YATES	477.8	222.1	3.2	19.3	18.4	3152.6	500.8	224.5	3.3	20.5	19.6	3173.5

Total For Counties in Marcellus Shale Area	104,080	40,983	741	4,379	4,170	614,703		104,767	41,053	743	4,413	4,203	615,372

Estimated additional mobile source emissions resulting from additional VMT associated with proposed gas drilling *

NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
686.7	70.0	2.5	34.4	33.3	668.6
Well pad emissions assuming total emissions split equally across all					
0.28	0.03	0.00	0.01	0.01	0.27

Percentage increase in emissions assuming all wells operating

NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
0.66%	0.17%	0.33%	0.79%	0.80%	0.11%

* Does NOT include Evaporative emissions processes

Marcellus Single Pad MOBILE Model Emissions of PM2.5 for CP-33 Comparison

Vehicle Trip Emissions						
Vehicle Type	**Range of Trucks**	**Max Number of Trucks**	**Feet travelled per site***	**Distance travelled per truck (miles)**	**PM 2.5 EF (lbs/mile)**	**Emissions (tons)**
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0003	2.18799E-06
Drilling Rig	30	30	1700	9.66	0.0003	1.45866E-06
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0003	2.4311E-06
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0003	2.4311E-06
Completion Rig	15	15	1700	4.83	0.0003	7.2933E-07
Completion Fluid and Materials	10-20	20	1700	6.44	0.0003	9.72439E-07
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0003	2.4311E-07
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0003	9.72439E-06
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0003	2.91732E-05
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0003	1.21555E-06
Flow Back Water Removal	200-300	300	1700	96.59	0.0003	1.45866E-05
Total		**1340**		**431.44**		**6.51534E-05**

*(1 - 750 foot trip onto site, 1 - 100 foot trip to station, 1- 100 foot trip back from the station and 1-750 foot trip off the site)

Vehicle Idle Emissions						
Vehicle Type	**Range of Trucks**	**Max Number of Trucks**	**Idle Time per truck (hrs)****	**Hours idling per truck type (hrs)**	**PM 2.5 EF (lbs/hr)**	**Emissions (tons)**
Drill Pad and Road Construction Equipment	10-45	45	2	90.00	0.0013	5.74901E-05
Drilling Rig	30	30	2	60.00	0.0013	3.83267E-05
Drilling Fluid and Materials	25-50	50	2	100.00	0.0013	6.38779E-05
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	2	100.00	0.0013	6.38779E-05
Completion Rig	15	15	2	30.00	0.0013	1.91634E-05
Completion Fluid and Materials	10-20	20	2	40.00	0.0013	2.55511E-05
Completion Equipment – (pipe, wellhead)	5	5	2	10.00	0.0013	6.38779E-06
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	2	400.00	0.0013	0.000255511
Hydraulic Fracture Water	400-600	600	2	1200.00	0.0013	0.000766534
Hydraulic Fracture Sand	20-25	25	2	50.00	0.0013	3.19389E-05
Flow Back Water Removal	200-300	300	2	600.00	0.0013	0.000383267
Total		**1340**		**2680.00**		**0.001711927**

** Assume each truck idles at least 2 hours over the duration of the project

Road Dust Emissions						
Vehicle Type	**Range of Trucks**	**Max Number of Trucks**	**Feet travelled per site***	**Distance travelled per truck (miles)**	**PM 2.5 EF (lbs/mile)**	**Emissions (tons)**
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0863	0.000625511
Drilling Rig	30	30	1700	9.66	0.0863	0.000417007
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0863	0.000695012
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0863	0.000695012
Completion Rig	15	15	1700	4.83	0.0863	0.000208504
Completion Fluid and Materials	10-20	20	1700	6.44	0.0863	0.000278005
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0863	6.95012E-05
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0863	0.002780047
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0863	0.008340142
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0863	0.000347506
Flow Back Water Removal	200-300	300	1700	96.59	0.0863	0.004170071
Total		**1340**		**431.44**		**0.018626317**

Total PM 2.5 Emissions	**Emissions (tons)**	**Emissions (lbs)**
Vehicle Trip Emissions	6.51534E-05	0.13
Vehicle Idle Emissions	0.001711927	3.42
Road Dust Emissions	1.86E-02	37.25
Total	**0.02**	**40.81**

NEW YORK
STATE OF OPPORTUNITY.

Department of Environmental Conservation

Appendix 19

Greenhouse Gas (GHG) Emissions

Final

Supplemental Generic Environmental Impact Statement

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Part A

GHG Tables

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GHG Tables (Revised July 2011, following replaces tables released in September 2009)

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

	Single Vertical, Single Horizontal or Four-Well Pad[3]				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation [4]	432	NA	NA	4	NA
Drill Pad and Road Construction [5]	NA	48 hours	NA	11	NA
Total Emissions	432	NA	NA	15	NA

Table GHG-3 – Completion Rig Mobilization and Demobilization – GHG Emissions

	Single Vertical, Single Horizontal or Four-Well Pad				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Completion Rig[6]	432	NA	NA	4	NA
Total Emissions	432	NA	NA	4	NA

[3] Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered.
[4] ALL Consulting, 2011, Exhibit19B.
[5] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[6] ALL Consulting, 2011, Exhibit19B. Completion rig mobilization likely less than that for drilling rig but for simplification assumed the same.

Table GHG-4 – Well Drilling – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[7]	788	NA	NA	NA	9	NA
Power Engines[8]	NA	132 hours	1	NA	74	NA
Circulating System[9]	NA	132 hours	1	negligible	NA	negligible
Well Control System[10]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	83	negligible

[7] ALL Consulting, 2011, Exhibit 20B.
[8] 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.
[9] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[10] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-5 – Well Drilling – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[11]	2,298	NA	NA	NA	26	NA
Power Engines[12]	NA	300 hours	1	NA	168	NA
Circulating System[13]	NA	300 hours	1	negligible	NA	negligible
Well Control System[14]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	194	negligible

[11] ALL Consulting, 2011, Exhibit19B.
[12] 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.
[13] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[14] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-6 – Well Drilling – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[15]	9,192	NA	NA	NA	104	NA
Power Engines[16]	NA	1,200 hours	1	NA	672	NA
Circulating System[17]	NA	1,200 hours	1	negligible	NA	negligible
Well Control System[18]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	776	negligible

[15] ALL Consulting, 2011, Exhibit19B.
[16] 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.
[17] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[18] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-7 – Well Completion – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[19]	818	NA	1	NA	9	NA
Hydraulic Fracturing Pump Engines	NA	4,833 gallons[20]	1	NA	54	NA
Line Heater	NA	72 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	72 hours	1	NA	NA	negligible
Flare Stack[21]	NA	72 hours	1	12[22]	1,728[23]	NA
Rig Engines[24]	NA	12 hours	1	NA	4	NA
Site Reclamation[25]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[26]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	1,804	negligible

[19] ALL Consulting, 2011, Exhibit 20B.
[20] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10. Assumed vertical job is one-sixth of high-volume job.
[21] Assumed no use of reduced emission completion ("REC").
[22] 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. . Vertical well not likely to produce at assumed rate due to reduced completion interval.
[23] 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. Vertical well not likely to produce at assumed rate due to reduced completion interval.
[24] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[25] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[26] ALL Consulting, 2011, Exhibit 20B.

Table GHG-8 – Well Completion – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[27]	2,462	NA	1	NA	28	NA
Hydraulic Fracturing Pump Engines	NA	29,000 gallons[28]	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[29]	NA	72 hours	1	12[30]	1,728[31]	NA
Rig Engines[32]	NA	24 hours	1	NA	7	NA
Site Reclamation[33]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[34]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	2,097	negligible

[27] ALL Consulting, 2011, Exhibit 19B.
[28] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10.
[29] Assumed no use of reduced emission completion ("REC").
[30] 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.
[31] 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.
[32] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[33] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[34] ALL Consulting, 2011, Exhibit 19B.

Table GHG-9 – Well Completion – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[35]	9,848	NA	NA	NA	112	NA
Hydraulic Fracturing Pump Engines	NA	116,000 gallons	NA	NA	1,300	NA
Line Heater	NA	288 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	288 hours	1	NA	NA	negligible
Flare Stack[36]	NA	288 hours	1	48	6,912	NA
Rig Engines[37]	NA	96 hours	1	NA	28	NA
Site Reclamation[38]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	48	8,361	negligible

[35] ALL Consulting, 2011, Exhibit 19B.
[36] Assumed no use of reduced emission completion ("REC").
[37] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[38] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

Table GHG-10 – First-Year Well Production – Single Vertical Well GHG Emissions[39]

	Single Vertical Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[40]	400	NA	NA	NA	1	NA
Wellhead	NA	8,376 hours[41]	1	NA	NA	negligible
Compressor	NA	8,376 hours	1	not determined	5,883[42] (&4[43])	123[44]
Line Heater	NA	8,376 hours	1	negligible	negligible	negligible
Separator	NA	8,376 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,376 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,376 hours	1	22[45]	3[46]	negligible
Dehydrator Pumps	NA	8,376 hours	1	80[47]	NA	negligible
Pneumatic Device Vents	NA	8,376 hours	3	9[48]	NA	negligible
Meters/Piping	NA	8,376 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	8,376 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[49]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	111	5,894	123

[39] 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. However, vertical well not likely to produce at assumed rate due to reduced completion interval.
[40] Assumed roundtrip of 40 miles.
[41] Calculated by subtracting total time required to drill and complete one vertical well (16 days) from 365 days.
[42] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[43] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[44] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[45] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[46] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[47] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[48] Emissions Factor (EF) of 0.664 lbs per hour.
[49] Assumed roundtrip of 40 miles.

Table GHG-11 – First-Year Well Production – Single Horizontal Well GHG Emissions[50]

	Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[51]	400	NA	NA	NA	1	NA
Wellhead	NA	7,944 hours[52]	1	NA	NA	negligible
Compressor	NA	7,944 hours	1	not determined	5,580[53] (&4[54])	122[55]
Line Heater	NA	7,944 hours	1	negligible	negligible	negligible
Separator	NA	7,944 hours		NA	negligible	negligible
Glycol Dehydrator	NA	7,944 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	7,944 hours	1	21[56]	3[57]	negligible
Dehydrator Pumps	NA	7,944 hours	1	76[58]	NA	negligible
Pneumatic Device Vents	NA	7,944 hours	3	9[59]	NA	negligible
Meters/Piping	NA	7,944 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	7,944 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[60]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	106	5,591	122

[50] 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.
[51] Assumed roundtrip of 40 miles.
[52] Calculated by subtracting total time required to drill and complete one horizontal well (34 days) from 365 days.
[53] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[54] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[55] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[56] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[57] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[58] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[59] Emissions Factor (EF) of 0.664 lbs per hour.
[60] Assumed roundtrip of 40 miles.

Table GHG-12 – First-Year Well Production – Four-Well Pad GHG Emissions[61]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[62]	1,600	NA	NA	NA	3	NA
Wellhead	NA	5,496 hours[63]	1	NA	NA	negligible
Compressor	NA	5,496 hours	1	not determined	3,860[64] (&3[65])	80[66]
Line Heater	NA	5,496 hours	1	negligible	negligible	negligible
Separator	NA	5,496 hours		NA	negligible	negligible
Glycol Dehydrator	NA	5,496 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	5,496 hours	1	58[67]	8[68]	negligible
Dehydrator Pumps	NA	5,496 hours	1	210[69]	NA	negligible
Pneumatic Device Vents	NA	5,496 hours	3	6[70]	NA	negligible
Meters/Piping	NA	5,496 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	5,496 hours	2	negligible	NA	negligible
Production Brine Removal 176 Truckloads[71]	7,040	NA	NA	NA	11	NA
Total Emissions	NA	NA	NA	274	3,885	80

[61] 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.
[62] Assumed roundtrip of 40 miles.
[63] Calculated by subtracting total time required to drill and complete four horizontal wells (136 days) from 365 days.
[64] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[65] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[66] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[67] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[68] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[69] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[70] Emissions Factor (EF) of 0.664 lbs per hour.
[71] Assumed roundtrip of 40 miles.

Table GHG-13 – Post-First Year Annual Well Production – Single Vertical or Single Horizontal Well GHG Emissions[72]

	Single Vertical Well or Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[73]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[74] (&5[75])	128[76]
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[77]	3[78]	negligible
Dehydrator Pumps	NA	8,760 hours	1	84[79]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[80]	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 50Truckloads[81]	2,000	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	116	6,164	128

72 Assumed production 10 mmcfd per well.
73 Hours in 365 days.
74 Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
75 Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
76 One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
77 Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
78 Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
79 Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
80 Emissions Factor (EF) of 0.664 lbs per hour.
81 Assumed roundtrip of 40 miles.

Table GHG-14 – Post-First Year Annual Well Production – Four-Well Pad GHG Emissions[82]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[83]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[84] (&5[85])	128[86]
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	93[87]	12[88]	negligible
Dehydrator Pumps	NA	8,760 hours	1	335[89]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[90]	NA	negligible
Meters/Piping	NA	8,760 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	8,760 hours	2	negligible	NA	negligible
Production Brine Removal 200Truckloads[91]	8,000	NA	NA	NA	13	NA
Total Emissions	NA	NA	NA	437	6,183	128

[82] Assumed production 10 mmcfd per well.
[83] Hours in 365 days.
[84] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[85] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[86] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[87] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[88] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[89] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[90] Emissions Factor (EF) of 0.664 lbs per hour.
[91] Assumed roundtrip of 40 miles.

Table GHG-15 – Estimated First-Year Green House Gas Emissions from Single Vertical Well

	Single Vertical Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[92]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	83	negligible	negligible	83
Well Completion including Hydraulic Fracturing and Flowback	1,804	12	300	2,104
Well Production	5,894	234	5,850	11,744
Total	8,660	246	6,150	14,810

Table GHG-16 – Estimated First-Year Green House Gas Emissions from Single Horizontal Well

	Single Horizontal Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[93]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	194	negligible	negligible	194
Well Completion including Hydraulic Fracturing and Flowback	2,097	12	300	2,397
Well Production	5,591	228	5,700	11,291
Total	8,761	240	6,000	14,761

Table GHG-17 – Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical Well or Single Horizontal Well

	Single Vertical Well or Single Horizontal Well[94]			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[95]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,164	244	6,100	12,264

[92] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[93] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[94] Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval, and therefore emission estimates are conservative for vertical well production.
[95] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Table GHG-18 – Estimated First-Year Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[96]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	776	negligible	negligible	776
Well Completion including Hydraulic Fracturing and Flowback	8,361	48	1,200	9,561
Well Production	3,885	354	8,850	12,735
Total	13,901	402	10,050	23,951

Table GHG-19 – Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[97]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,183	565	14,125	20,300

[96] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[97] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Part B

Sample Calculations for Combustion Emissions from Mobile Sources

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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.

$$70{,}000 \frac{miles}{project} \times \frac{gallon_{diese}\ l}{7\ miles} = 10{,}000\ \frac{gallons\ diesel\ consumed}{project\ move}$$

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.

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NEW YORK STATE OF OPPORTUNITY.

Department of Environmental Conservation

Appendix 20

PROPOSED
Pre-Frac Checklist and Certification

Final

Supplemental Generic Environmental Impact Statement

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PRE-FRAC CHECKLIST AND CERTIFICATION

Well Name and Number:
(as shown on the Department-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. <u>Approval Date & Brief Description of Approved Revision(s)</u> *(attach additional sheets if necessary)*
☐	☐	All depths where fresh water, brine, oil and/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 radial cement bond evaluation log and narrative analysis of such, or other Department-approved evaluation, and consideration of appropriate supporting data per Section 6.4 "Other Testing and Information" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009) 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 not installed, or if was not production casing was not cemented to surface, then provide the date of approval by the Department and a brief description of justification. <u>Approval Date & Brief Description of Justification</u> *(attach additional sheets if necessary)*
☐	☐	Per Section 7.1 "General" under the heading "Well Construction Guidelines" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009), a representative blend of the cement used for the production casing was bench tested in accordance with API 10A Specification for Cements and Materials for Well Cementing (Twenty-Fourth Edition, December 2010) and was found to be of sufficient strength to withstand the maximum anticipated treatment pressure during hydraulic fracturing operations.
☐	☐	If fracturing operations will be performed down casing, then the pre-fracturing pressure tests required by permit conditions will be conducted and fracturing operations will only commence if the tests are 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.

PRE-FRAC CHECKLIST AND CERTIFICATION

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, and treatment plan must be received by the appropriate Regional office at least 3 days prior to the commencement of hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volume of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)). 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*, and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing and 3) all other pre-frac notification requirements are met as specified elsewhere. **The well owner 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.**

SIGNATURE SECTION

Signature Section - The person signing the *Pre-Frac Checklist And Certification* must be authorized to do so on the Organizational Report on file with the Division of Mineral Resources.

NEW YORK
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Department of
Environmental
Conservation

Appendix 21

Publicly Owned Treatment Works (POTWs) With Approved Pretreatment Programs

Final

Supplemental Generic Environmental Impact Statement

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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

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Appendix 22

POTW Procedures for Accepting High-Volume Hydraulic Fracturing Wastewater

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POTW Procedures for Accepting High-Volume Hydraulic Fracturing Wastewater

The following procedure shall be followed when a Publically Owned Treatment Works (POTW) proposes to accept high-volume hydraulic fracturing wastewater from a well driller or other development company. Page 5 of this appendix shows a simplified flowchart of this process. Please note that this disposal option is limited to the extent that municipal POTWs which utilize biological wastewater treatment are generally optimized for the removal of domestic wastewater and as such are not designed to treat several of the contaminants present in high-volume hydraulic fracturing wastewater. In addition to the above concerns, the additional monitoring and laboratory costs which will result from additional monitoring conditions in the permit must also be considered prior to deciding to accept this source of wastewater.

1. The POTW operator receives a request to accept flowback water from a well driller. Prior to submitting this request to the Department for approval, the POTW should review the request to assure that it includes, at a minimum:
    a. The volume of water to be sent to wastewater treatment plant in gallons per unit time (e.g. 25,000 gallons per day);
    b. Whether the discharge is a one-time disposal, or will be an ongoing source of wastewater to the POTW;
    c. A characterization of high-volume hydraulic fracturing wastewater quality including all high-volume hydraulic facturing parameters of concern and NORM analysis;
    d. A characterization of existing POTW wastewater quality including:
        i. Sample results for all high-volume hydraulic fracturing parameters of concern, and
        ii. the results of short term high intensity monitoring for both TDS (in mg/l) and Radium 226 (in piC/l), consisting of the results of ten (10) samples each of existing influent, sludge, and effluent from the POTW.
    e. The source of the wastewater (well name, well developer, Mineral Resources permit number, and location(s) of the wells); and

f. A list of all additives used in the hydraulic fracturing process at the source well(s).

2. The POTW shall forward the above request to the Bureau of Water Permits, 625 Broadway, Albany NY 12233-3505 along with the following supporting information:
    a. Documentation of existing EPA and Departmental approval of the facility's headworks analysis for the acceptance of high-volume hydraulic fracturing wastewater; or a completed headworks analysis for the high-volume hydraulic fracturing specific parameters of concern for Department and USEPA approval;
    b. Demonstration of available POTW capacity to accept the proposed volume of high-volume hydraulic fracturing wastewater; and
    c. Confirmation that the facility has an approved USEPA pretreatment or Department mini-pretreatment program as part of its SPDES permit.

3. The Division of Water will review the submitted information to determine whether the high-volume hydraulic fracturing wastewater source has been adequately characterized. If additional information is necessary, the Division of Water will request additional sampling and source information from the POTW.

4. The Division of Water will review the facility's SPDES permit to determine whether the permit needs to be modified to include high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions.

5. Concurrently with 3. and 4. above, if a headworks analysis for the high-volume hydraulic fracturing specific parameters of concern was submitted for approval, the Division of Water will forward a copy of the headworks analysis to the USEPA Region 2 office for its review and approval. The Division of Water and USEPA Region 2 will review the facility's headworks analysis to assure that the POTW is capable of accepting the proposed volume and quantity of high-volume hydraulic fracturing wastewater

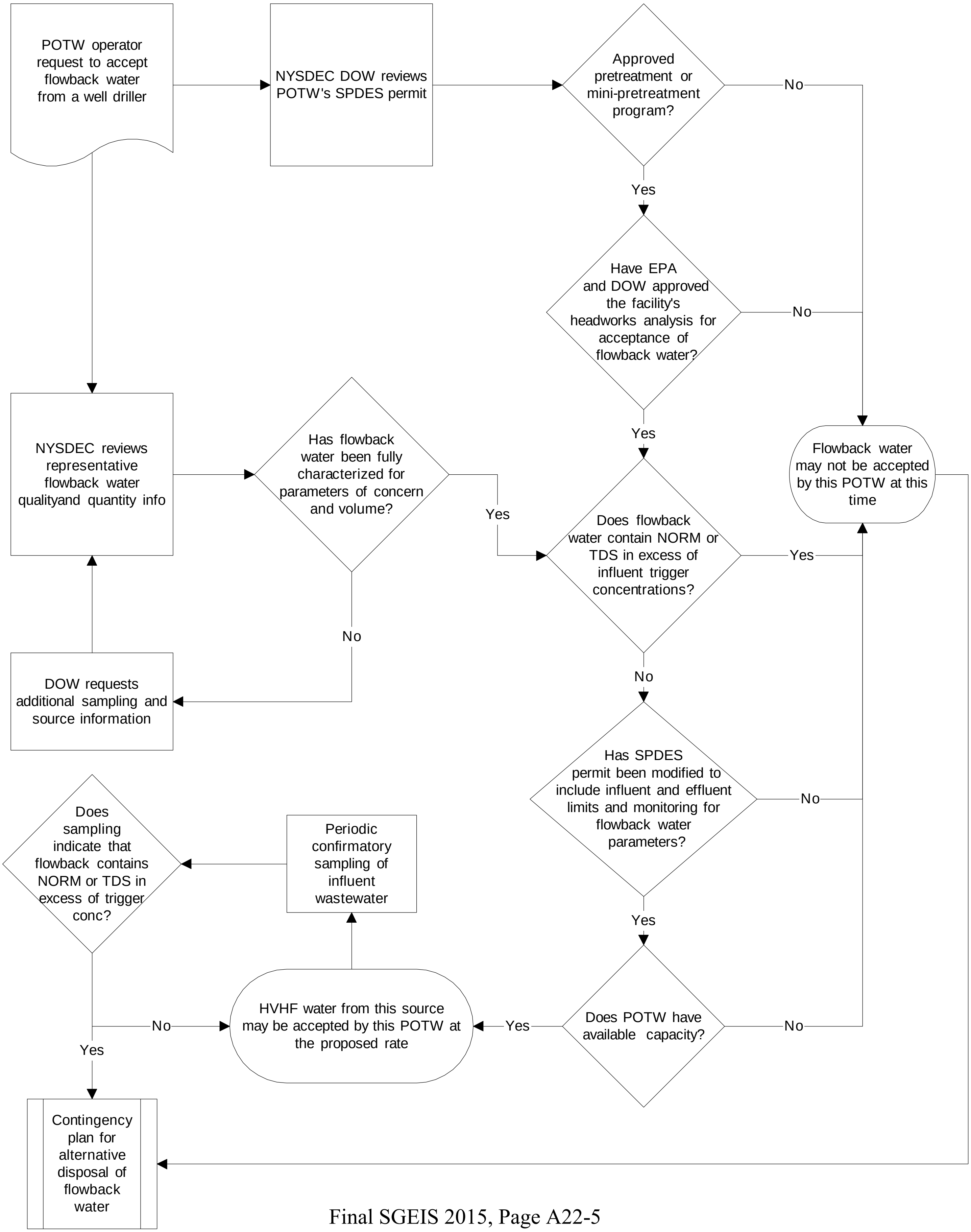
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations and requested discharge rate following receipt of Departmental approval, which will include the following components:
    a. Approval of submitted headworks analysis by the Department and USEPA; and
    b. SPDES permit modification with high-volume hydraulic fracturing specific monitoring, limits, and reporting conditions, including;
        i. Specification of the source and maximum discharge rate of the high-volume hydraulic fracturing wastewater to be accepted;
        ii. Influent radium-226 and TDS limits;
        iii. Effluent limits and/or monitoring for NORM, TDS, and other high-volume hydraulic fracturing parameters of concern;
        iv. Periodic confirmatory sampling of influent wastewater for high-volume hydraulic fracturing parameters of concern to assure that the characteristics of the influent wastewater have not changed substantially from the characterization provided in the approval request;
        v. periodic sludge sampling to assure that the concentration of radionuclides in the sludge do not exceed 5 piC/g; and
        vi. Any other monitoring conditions necessary to assure that the discharge from the POTW does not cause or contribute to a violation of NYS water quality standards.

7. If the Department does not approve the acceptance of flowback water, a written denial will be sent to the permittee with the reason(s) for denial. These reasons could include, but not be limited to: inadequate receiving water assimilative capacity, NORM concentrations in excess of the applicable influent Radium-226 limit of 15- piC/l, influent concentrations of any other parameters in excess of the levels acceptable in the approved headworks analysis, or inadequate POTW capacity.

8. Following approval and permit modification, the POTW must notify the Department whenever:
    a. The facility wishes to increase the quantity of high-volume hydraulic fracturing wastewater accepted from this source;
    b. The facility wishes to accept any volume of high-volume hydraulic fracturing wastewater from a new or additional source;
    c. The high-volume hydraulic fracturing wastewater contains NORM or TDS in excess of the influent limits for these parameters; or
    d. The facility has decided to stop accepting high-volume hydraulic fracturing wastewater from one or more sources.

The notifications in a. – c. would be treated as a request for a new source of high-volume hydraulic fracturing wastewater, and would be processed in accordance with Items 1-7 above.

Flowchart for acceptance of High Volume Hydraulic Fracturing (HVHF) wastewater by publicly owned treatment works (POTWs)



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Appendix 23

USEPA Natural Gas STAR Program

Final

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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

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Appendix 24

Key Features of USEPA Natural Gas STAR Program

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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.

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Appendix 25

Reduced Emissions Completion (REC) Executive Summary

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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 involves 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.

Conventional completion of wells (a process that cleans the well bore of stimulation fluids and solids so that the gas has a free path from the reservoir) results in gas being either vented or flared. Vented gas results in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions to the atmosphere while flared gas results in carbon dioxide emissions.

Reduced emissions completion (REC) – also known as reduced flaring completion – 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 so that the gas is suitable for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during the well flowback phase 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]Adapted from 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.

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Appendix 26

Instructions for Using the On-Line Searchable Database to Locate Drilling Applications

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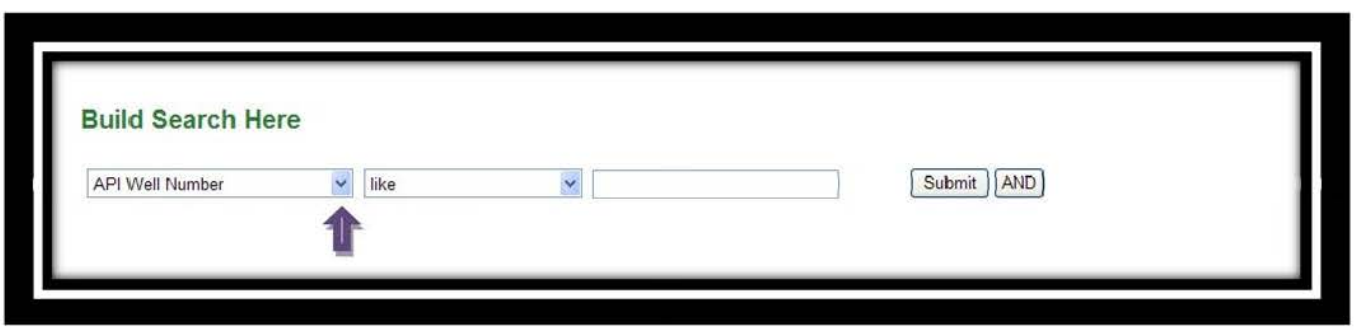
How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

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.

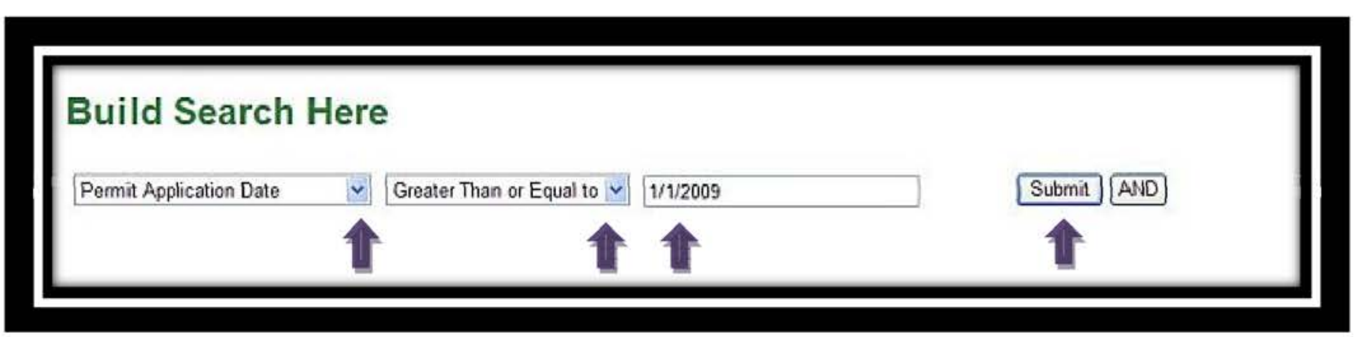
How to Conduct a Simple Search

1. Select Wells Data to begin your search.

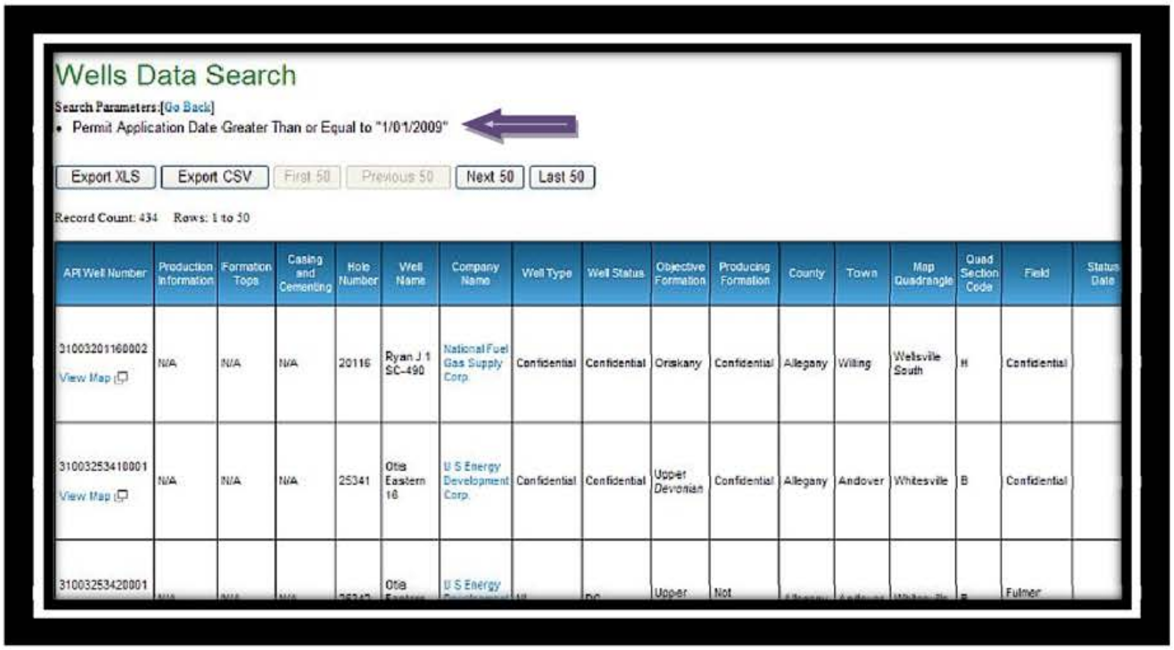
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.



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 Data is Greater Than or Equal to 1/1/year to find all permit applications filed during a specific year. Click the Submit button.



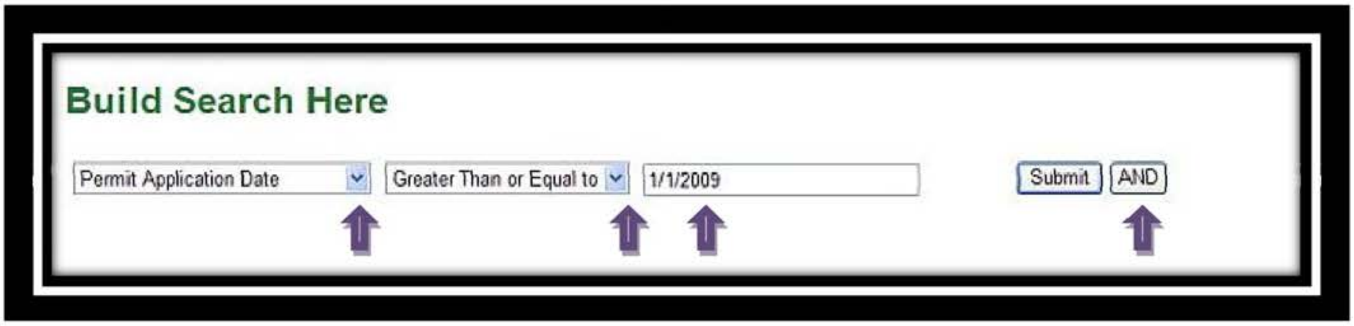
4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) by clicking the appropriate Export button at the bottom the results screen. Clicking a hyperlink in the Company Name column will provide contact information for the company.



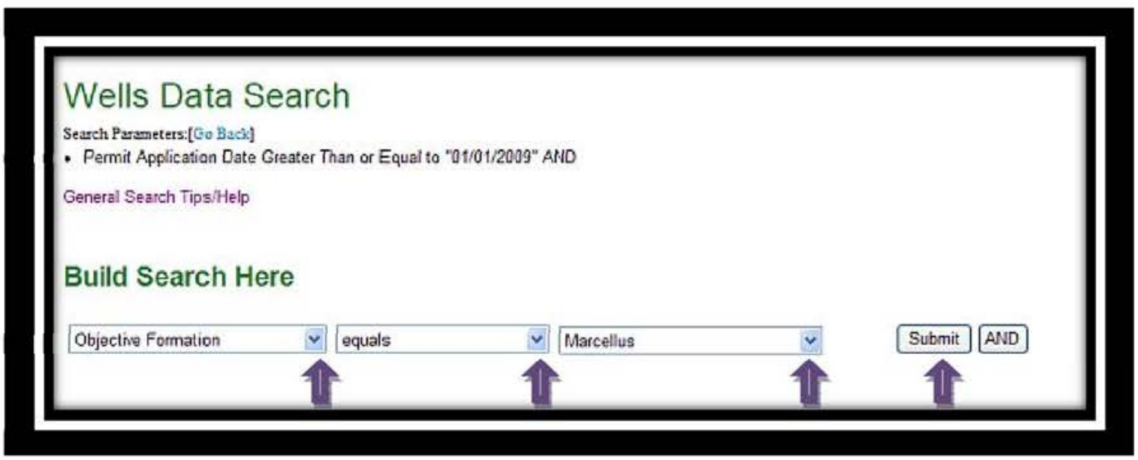
How to Narrow or Expand Your Search Utilizing the AND Button

1. Select Wells Data to begin your search.

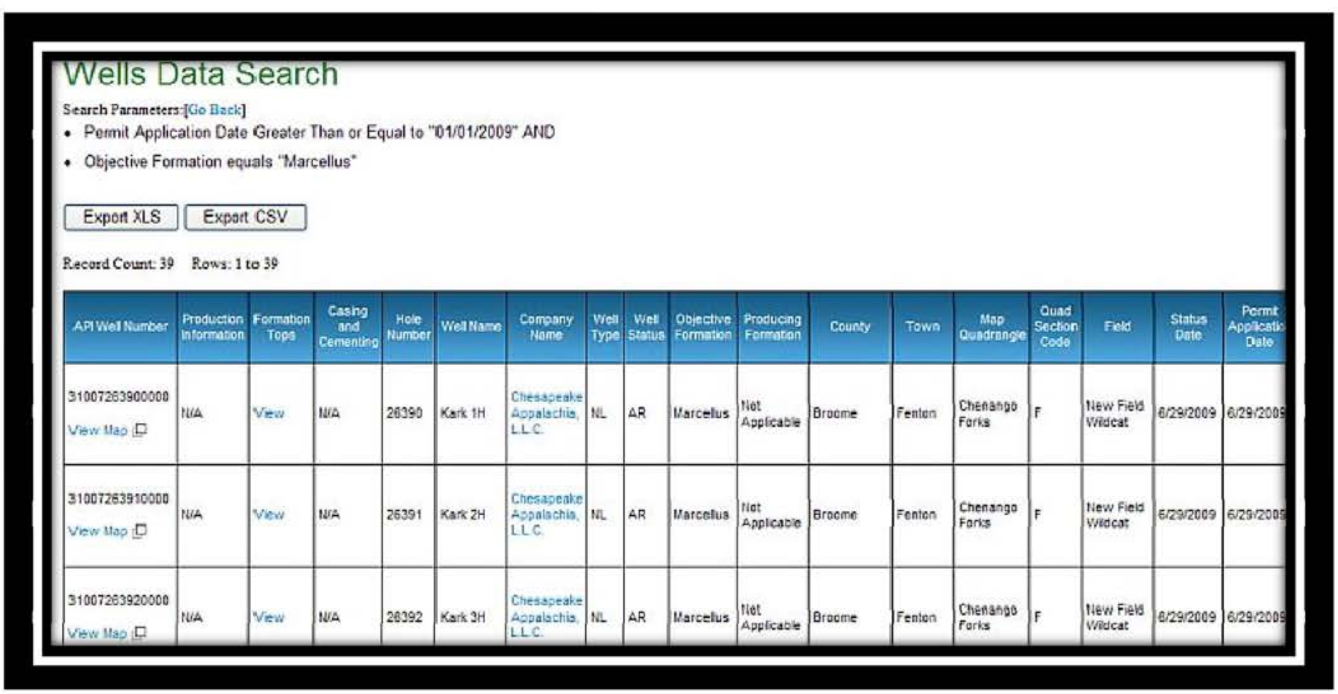
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permit applications filed in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Click the Submit button.



4. View Results.

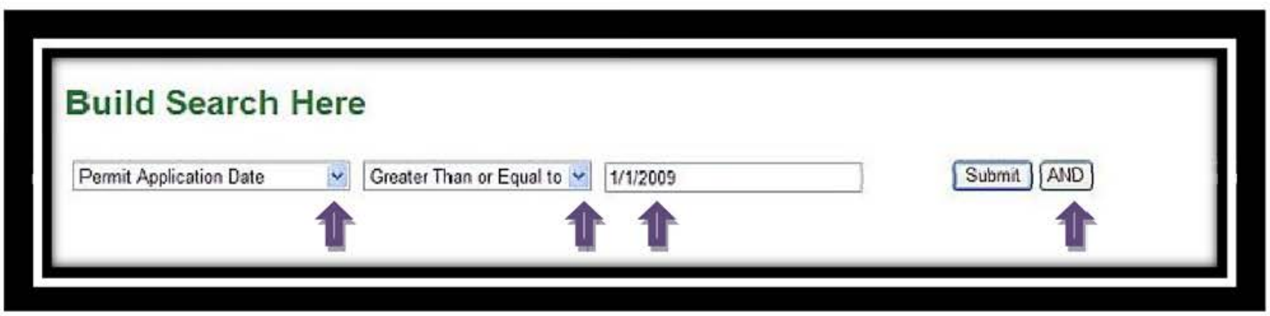


API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date	Permit Applicatio Date
31007263900000 View Map	N/A	View	N/A	26390	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 Narrow Your Search to Applications Submitted For a Specific County

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all permit applications 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.

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Appendix 27

NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

Final

Supplemental Generic Environmental Impact Statement

Radiological Survey Requirements

I. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

II. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

III. Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

IV. Survey Frequency

Radiological survey data must be conducted within 6 months following the start of gas production and at intervals not to exceed 12 months thereafter.

The permit tee must conduct surveys of all equipment used on the production train prior to disposal, recycling or transfer to any entity.

Equipment that exceeds 50microrem/hr is subject licensure by the New York State Department of Health.

V. Survey data reports

Survey data must be submitted within 30 days following the survey, and must contain the information required by Section III.

NEW YORK STATE
DEPARTMENT OF HEALTH
BUREAU OF ENVIRONMENTAL RADIATION PROTECTION

Radiation Guide 1.15

GUIDE FOR APPLICATION TO POSSESS NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM) INCIDENT TO NATURAL GAS INDUSTRY

I. INTRODUCTION

PURPOSE OF GUIDE

The purpose of this regulatory guide is to provide assistance to applicants in preparing applications for new licenses for the possession of naturally occurring radioactive materials (NORM) incident to natural gas exploration and production. This regulatory guide is intended to provide you, the applicant, with information that will enable you to understand specific regulatory requirements and licensing policies as they apply to the license activities proposed.

After you are issued a license, you must conduct your program in accordance with (1) the statements, representations and procedures contained in your application; (2) the terms and conditions of the license; and (3) the Department of Health's regulations in 10 NYCRR 16 and 12 NYCRR 38. The information you provide in your application should be clear, specific and accurate.

II. FILING AN APPLICATION

You, as the applicant for a materials license, must complete Items 1 through 4 and 18 on the attached application form. For other applicable Items, submit the information on supplementary pages. Each separate sheet or document submitted with the application should be identified and keyed to the item number on the application to which it refers. All typed pages, sketches, and, if possible, drawings should be on 8 ½ x 11 inch paper to facilitate handling and review. If larger drawings are necessary, they should be folded to 8 ½ x 11inches. You should complete all items in the application in sufficient detail for the Department to determine that your equipment, facilities, training and experience, and radiation safety program are adequate to protect health and to minimize danger to life and property.

You must submit two copies of your application with attachments. Retain one copy of the application for yourself, because the license will require that you possess and use licensed material in accordance with the statements and representations in your application and in any supplements to it.

Mail your completed application and the required non-refundable triennial fee ($3000) to:

New York State Department of Health
Bureau of Environmental Radiation Protection
Flanigan Square, 547 River Street
Troy, New York 12180

Please Note: Applications received without fees will not be processed .

III. CONTENTS OF AN APPLICATION

Item 1. Name and address.

Enter the name and corporate address of the applicant and the telephone number of company management. The name of the firm must appear exactly as it appears on legal papers authorizing the conduct of business. Indicate if the name and address are different from those listed on the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill.

Item 2A. Addresses at which radioactive material will be used.

List all addresses and locations where radioactive material will be used or stored, i.e., the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill Nos., well name, and town name.

2.B. Not applicable

Item 3. Nature of business

Enter the nature of the business the applicant is engaged in and the name and telephone number (including area code) of the individual to be contacted in connection with this application.

Item 4. Previous radioactive materials license

Enter any previous or current radioactive materials license numbers and identify the issuing agency. Also indicate whether you possess any radioactive material under a general license.

Describe the circumstances of any denial, revocation or suspension of a radioactive materials license previously held.

Item 5. Department to Use Radioactive Material

Not Applicable

Item 6. Individual Users of Radioactive Materials

Not Applicable,

Item 7. Radiation Safety Officer

State the name, title and contact information (phone, fax, and e-mail) of the person designated by, and responsible to, management for the coordination of the radiation safety program. This person will be named on the license as the Radiation Safety Officer. He/she will be responsible to oversee and ensure that licensed radioactive material is possessed in accordance with regulations and the radioactive materials license.

Item 8. Radioactive Material

No response is required. The license will list Naturally Occurring Radioactive Material (NORM).

Item 9. Purpose for which Radioactive Material Will be Used

No response is required. (The type of use will be specified on the license as possession and maintenance of radiologically contaminated equipment, with specific limitations.)

Item 10. Training of individual users

Persons who perform radiological surveys that are required by regulation and radioactive materials license must receive initial and annual radiation protection training. The scope of training needs to be commensurate with their duties. Appendix A contains a model training program. Confirm that you will follow the model or submit your proposed training program for review.

Item 11. Experience with radioactive materials for individual users

No response is required. Implementation of a training program as required in Item 10 of the application addresses Item 11 for the scope of license tasks.

Item 12. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

A model procedure for conducting a radiological survey is provided in Appendix C.

Item 13. Calibration and operational checks of instrumentation

Instrument calibrations must be performed before first use of the instrument and at intervals not to exceed 12 months by an entity that is licensed by the US Nuclear Regulatory Commission or an Agreement State to perform radiological survey instrument calibrations. The instrument must be checked for proper operation (minimally a battery condition check must be performed, and a response to a radiation source is recommended) on each day of use. Records of instrument calibrations must be maintained for a period of 5 years for review by the Department. Confirm that calibrations and daily battery checks will be performed as indicated above and that instrument calibration records will be maintained.

Item 14. Personnel monitoring and bioassays

Not applicable.

Item 15. Facilities and Equipment

Submit simple sketches of any storage area(s), pipe yards, etc., for contaminated equipment.

Item 16. Radiation Protection Program

The applicant does not need to establish a comprehensive radiation safety program. However, the applicant needs to implement a radiation protection program that is commensurate with the type of radioactive material authorized by the license. Appendix B contains a model radiation protection program. Please confirm that you will implement the model program or submit your proposed program for review.

Item 17. Waste Disposal

The applicant must plan for proper disposal of radiologically contaminated equipment when their use has been discontinued. Confirm that you will dispose of radiologically contaminated items in accordance with all applicable state and federal requirements.

Item 18. Certification

Provide the signature of the chief executive officer of the corporation or legal entity applying for the license or of an individual authorized by management to sign official documents and to certify that all information in this application is accurate to the best of the signator's knowledge and belief.

IV. AMENDMENTS TO LICENSES

Licensees are required to conduct their programs in accordance with statements, representations and procedures contained in the license application and supporting documents. The license must therefore be amended if the licensee plans to make any changes in the facilities, equipment, procedures, and authorized users or radiation safety officer, or the radioactive material to be used.

Applications for license amendments may be filed either on the application form or in letter form. The application should identify the license by number and should clearly describe the exact nature of the changes, additions, or deletions. References to previously submitted information and documents should be clear and specific and should identify the pertinent information by date, page and paragraph.

APPENDIX A   Training Program for Individuals Performing Radiological Survey Measurements.

The applicant/licensee may use the services of a health physicist, licensed medical physicist or an individual who is authorized by a radioactive materials license to conduct radiological surveys. In these situations, the applicant/licensee needs to obtain documentation that the individual is qualified. Examples of documentation include a radioactive materials license that names the person as an authorized user, or copy of a resume for the health physicist or licensed medical physicist. Records of training must be maintained for a period of 5 years.

However, if the applicant/licensee plans to use his/her staff to conduct surveys, such individuals must receive training.

Individuals must demonstrate competence in the following subjects that prior to being approved to perform required surveys. Training must be conducted by an individual who is knowledgeable in health physics principles and procedures.

I. Fundamentals of Radiation Safety

A. Characteristics of radiation
B. Units of radiation dose and quantity of radioactivity
C. Levels of radiation from sources of radiation
D. Methods of minimizing radiation dose:
1. working time
2. working distance
3. shielding

II. Radiation Detection Instruments

A. Use of radiation survey instruments
1. operational
2. calibration

B. Survey techniques

III. Requirements of the regulations and License Conditions

IV. Records of training will be maintained for a period of 5 years. Records will include the date of training, name of persons trained, name of the trainer and his/her employer, a copy of the training agenda or topics covered, and the results of any test or determination of proficiency. Records will be maintained for review by the Department.

APPENDIX B   Radiation Protection Program

I. Responsibility

A. The owner/licensee will delegate authority to the Radiation Safety Officer to implement the program and the responsibility to oversee the day to day oversight of the program

B. Ensure that individuals receive initial and annual radiation protection training.

C. Ensure that radiological surveys are performed in an effective manner and at the time intervals required by the License.

D. Ensure that notifications required by regulations and License Conditions are made.

E. Ensure that an inventory of radiologically contaminated equipment is maintained.

F. Ensure that contaminated equipment in storage is labeled as containing radioactive material and is not released for unrestricted use.

G. Ensure that radioactive waste is disposed in accordance with all applicable state and federal requirements.

H. Ensure that only entities that have a specific license to perform decontamination perform service of equipment that exceeds 50 microrem at any accessible surface.

II. Maintain Records of:

A. Radiation Protection Training Program

B. Results of radiological surveys including instrumentation calibrations and operational checks.

C. Inventories of contaminated equipment

D. Waste disposal records

E. Service of contaminated equipment that exceeds 50 microrem at any accessible surface, including documentation of the service provider's radioactive materials license.

F. Radiological survey data

G. Maintain a complete radioactive materials license

APPENDIX C

Radiological Survey Guidance

I. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

II Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

NEW YORK STATE DEPARTMENT OF HEALTH
RADIOACTIVE MATERIALS LICENSE

Pursuant to the Public Health Law and Part 16 of the New York State Sanitary Code, and in reliance on statements and representations heretofore made by the licensee designated below, a license is hereby issued authorizing radioactive material(s) for the purpose(s), and at the place(s) designated below. The license is subject to all applicable rules, regulations, and orders now or hereafter in effect of all appropriate regulatory agencies and to any conditions specified below.

---

1. Name

____

2. Address

____
____

Attention:
Radiation Safety Officer

3. License Number

4. a. Effective Date

____

b. Expiration Date

____

5. Reference Number
DH No. _____

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6. Radioactive Materials (element & mass no.)	7. Chemical and/or Physical Form	8. Maximum quantity licensee may possess at one time
A. Radium 226	A. Any	A. As necessary
B. Naturally Occurring Radioactive Material (NORM)	B. Any	B. As necessary

9. Authorized use. The authorized locations of use are those specified in New York State Department of Environmental Conservation Permit to Drill Nos. __________.

A. The licensee is authorized for possession only of NORM listed in License Condition No. 6 as contamination in equipment incidental to oil and gas exploration and production.

B. The licensee may perform maintenance, not inculding decontamination or removal of scale containing radioactive material on equipment that does not exceed 50 microrem per hour at any accessible point.Only a licensee authorized by the US Nuclear Regulatory Commission or an

Agreement State to perform decontamination and decommissioning services shall service equipment that exceeds 50 microrem per hour at any accessible point.

10. A. Radioactive material listed in Item 6 shall be used by, or under the supervision of the Radiation Safety Officer.

____________ B.

C. The licensee shall notify the Department by letter within 30 days if the Radiation Safety Officer permanently discontinues performance of duties under the license.

11. Except as specifically provided otherwise by this license, the licensee shall possess and use licensed material described in Items 6, 7 and 8 of this license, in accordance with statements, representations, and procedures contained in the documents (including any enclosures) listed below:

A. Application for New York State Department of Health Radioactive Materials License dated ___________, signed by ___________.

B. Letter dated ___________, signed by _____________.

The New York State Department of Health's regulations shall govern the licensee's statements in applications or letters unless the statements are more restrictive than the regulations.

12. A. Transportation of licensed radioactive material shall be subject to all regulations of the U.S. Department of Transportation and other agencies of the United States having jurisdiction insofar as such regulations relate to the packaging of radioactive material, marking and labeling of the packages, loading and storage of packages, monitoring requirements, accident reporting, and shipping papers.

B. Transportation of low level radioactive waste shall be in accordance with the regulations of the New York State Department of Environmental Conservation as contained in 6 NYCRR Part 381.

13. The licensee shall have available appropriate survey instruments which shall be maintained operational and shall be calibrated before initial use and at subsequent intervals not exceeding twelve months by a person specifically authorized by the U.S. Nuclear Regulatory Commission or an Agreement State to perform such services. Records of all calibrations shall be kept a minimum of five years.

14, The licensee shall conduct gamma exposure rate measurements of accessable areas of gas production equipment within 6 months of the effective date of the license and at subsequent intervals not to exceed 12 months. The licensee shall maintain measurement records for review by the Department. The licensee shall notify the Department within 7 calendar days following identification of any exposure rate measurement that meet or exceed 2 millirem per hour. Notification may be made by phone or in writing.

15. Equipment in storage that exceeds 50 microrem per hour at any accessible point shall be labeled by means of paint or durable label or tag.

16. The licensee shall maintain an inventory of equipment, including but not limited to tubular goods, piping, vessels, wellheads, separators, etc., that exceeds 50 microrem per hour at any accessible point. The records of the inventories shall be maintained for inspection by the Department, and shall include the location and description of the items, and the date that items were entered on the inventory record.

17. A. Before treatment or disposal of any gas production water in a manner that could result in discharge or release to the environment, the licensee shall obtain from the New York State Department of Environmental Conservation either:

    i) A valid permit, or

    ii) A letter stating that no permit is required.

    B. The licensee shall maintain the letter or valid permit required in paragraph A of this condition on file for the duration of the license and make such letter or permit available for inspection by the Department upon request.

18. The licensee shall submit complete decontamination procedures to the Department for approval ninety (90) days prior to the termination of operations involving radioactive materials.

19. Plans of facilities which the licensee intends to dedicate to operations involving the use of radioactive material shall be submitted to the Department for review and approval prior to any such use.

20. The licensee shall maintain records of information important to safe and effective decommissioning at the location listed in License Condition No. 2 and at other locations as the licensee chooses. The records shall be maintained until this license is terminated by the Department and shall include:

    A. Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site;

    B. As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and locations of possible inaccessible contamination, such as buried pipes, which may be subject to contamination;

C. Records of the cost estimate performed for the decommissioning funding plan or the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

21. The licensee may transfer contaminated equipment that exceeds 50 microrem at any accessible point to a Department licensee if the equipment is to be used in the oil and gas industry. The licensee shall maintain records of each transfer of equipment authorized by this License Condition.

FOR THE NEW YORK STATE DEPARTMENT OF HEALTH

Date: By ______________________________
CJB/ :

Charles J. Burns, Chief
Radioactive Materials Section
Bureau of Environmental Radiation Protection

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