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."[5]

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.[6] 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

[5] 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.

[6] Chesapeake Energy Corp., Fortuna Energy Inc., Seneca Resources Corp.

immediately after the well has been fractured and completed, otherwise the formation may be 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.[7] 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.

[7] 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.[8] The

[8] 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.[9]

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,[10] 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

[9] OSHA, http://www.osha.gov/about.html.

[10] 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[11] and common name(s)[12] of the hazardous chemical[13] 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;

[11] 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.”

[12] 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.”

[13] 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.[14]

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[15] 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.[16]

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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[14] USEPA, August 2010.

[15] 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.

[16] 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.[17] 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."

[17] 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.[18]

§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;

[18] 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.[19] 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).[20]

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.[21]

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

[19] USEPA Fact Sheet for Subpart W, November 2010.

[20] Federal Register. November 30, 2010, p. 74462.

[21] 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[22] 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

[22] 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.[23]

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;[24] or
- a maximum impoundment capacity equal to or greater than three million gallons.[25]

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.

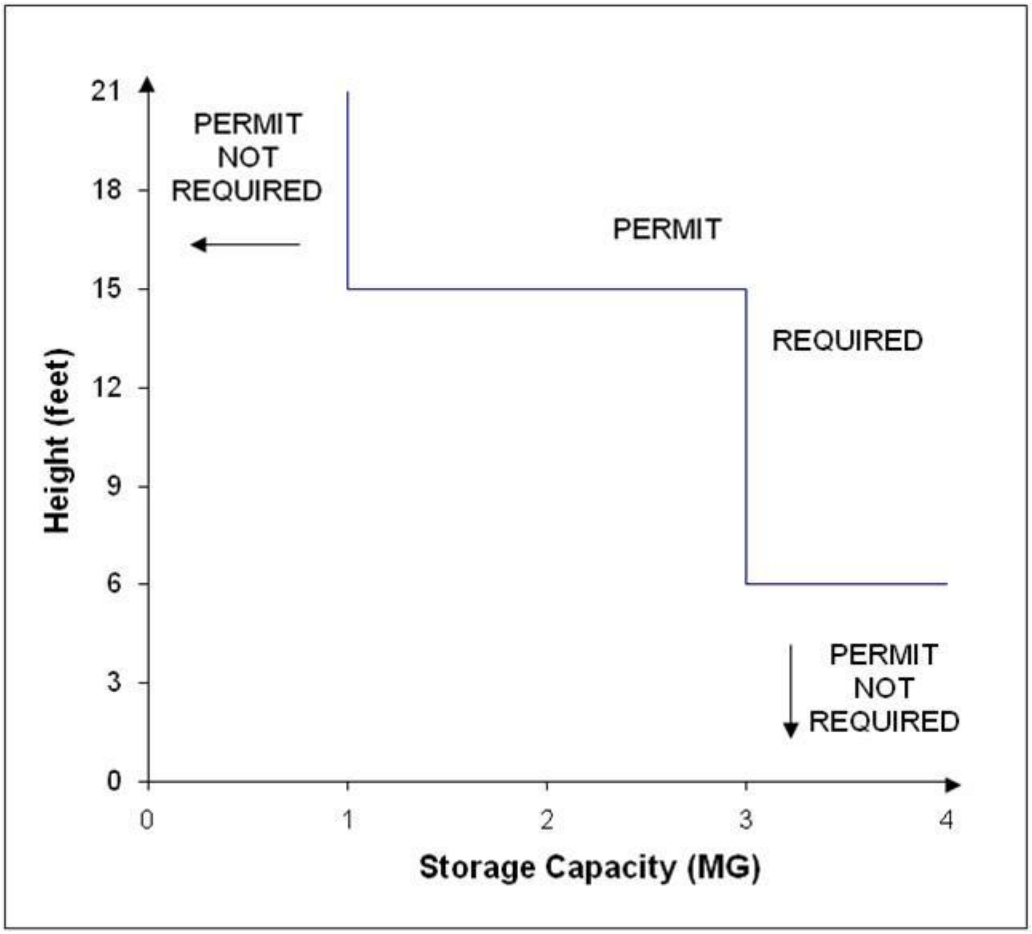
[23] NYSDEC Notice of Adoption of Amendments to Dam Safety Regulations.

[24] 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.

[25] 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[26] and from the Regional Permit Administrator[27] for the county where the impoundment project is proposed. A complete application package[28] 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;

[26] Downloadable permit application forms are available at http://www.dec.ny.gov/permits/6338.html.

[27] 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.

[28] 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,"[29] 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[30]; hydrology[31]; 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

[29] "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.

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

[31] 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.[32] 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

[32] 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,"[33] 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.

[33] 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 1×10^{-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."[34] 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;

[34] 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.[35]

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);

[35] 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.[36] 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;

[36] 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.[37] 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:

[37] 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.[38]

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

[38] 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.[39] 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.

[39] http://www.pacode.com/secure/data/025/chapter78/chap78toc.html "Chapter 78. Oil and Gas Wells.

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New York State

DEC

Chapter 9

Alternative Actions

Revised Draft
Supplemental Generic Environmental Impact Statement

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Chapter 9 – Alternative Actions

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. However, at the same time, none of the substantial economic benefits identified in Chapters 2 and 6 would occur either. Furthermore, this important energy source would not be harvested, which would be contrary to New York State and national interests. It would also contravene Article 23-0301 of the ECL where it is stated:

> *It is hereby declared to be in the public interest to regulate the development, production and utilization of natural resources of oil and gas in this state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas may be had, and that the correlative rights of all owners and the rights of all persons including landowners and the general public may be fully protected, and to provide in similar fashion for the underground storage of gas, the solution mining of salt and geothermal, stratigraphic and brine disposal wells.*

As more fully described in Chapter 2, the Marcellus Shale, 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.[1] While it is very early in the productive life of Marcellus Shale wells, more recent estimates by Engelder (2009) using well production decline rates indicate a 50% probability that recoverable reserves could be as high as 489 Tcf.[2]

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

> Production and use of in-state energy resources – renewable resources and natural gas – can increase the reliability and security of our energy systems, reduce energy costs, and contribute to meeting climate change, public health and environmental objectives. Additionally, by focusing energy investments on in-state opportunities, New York can reduce the amount of dollars "exported" out of the State to pay for energy resources.[3]

[1] Considine et al., 2009, p. 2.
[2] Considine et al., 2009, p. 2.
[3] NYS Energy Planning Board, August 2009.

The Draft Energy Plan further includes a recommendation to encourage development of the Marcellus Shale natural gas formation with environmental safeguards that are protective of water supplies and natural resources.[4]

The New York State Commission on Asset Maximization recommends that "Taking into account the significant environmental considerations, the State should study the potential for new private investment in extracting natural gas in the Marcellus Shale on State-owned lands, in addition to development on private lands." The Final report 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 and increase wealth to upstate landowners, and increase State revenue from taxes and land-owner leases and royalties. Development of State-owned lands could provide much needed revenue relief to the State and spur economic development and job creation in economically depressed regions of the State.[5]

The no-action alternative is also not favored because most of the potential significant adverse impacts identified in this Supplement can be fully mitigated by the measures outlined in Chapter 7. Other significant adverse impacts can be partially mitigated, or are temporary in nature. A prohibition would also deny owners of mineral interests an opportunity to realize the benefit of mineral rights ownership. Accordingly, it is not a recommended alternative to the rational and controlled development proposed in this Supplement.

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 Department's proposed program partially adopts this alternative by restricting resource development in the NYC and Syracuse watersheds (plus buffer), public water supplies, primary aquifers and certain

[4] NYS Energy Planning Board, August 2009.
[5] NYS Commission on Asset Maximization, June 2009.

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 are recommended and further limit the areas with site disturbances.

The Department does not believe that resource development should be further limited by imposing an annual limit on permits issued for high-volume hydraulic fracturing operations or any other formal phasing plan. The Department believes any such annual limit would be arbitrary. Rather, the Department proposes to limit permit issuance 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.

In addition, 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 will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource; rig, equipment and crew availability; permitting and oversight capacity; leasing, and most importantly economic factors. This holds true regardless of the type of drilling and stimulation utilized.

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.[6]

[6] ALL Consulting, 2010, p. 6

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.)[7]

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.[8]

9.2.3 Prohibitions and Limits that Function as a Partial Phased Permitting Approach

As set forth below, the Department's proposed program partially adopts a phased approach because it restricts 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 are recommended and further limit the areas where site disturbances would be allowed for a certain period of time.

[7] NTC Consultants, 2011, p. 36
[8] Dutton and Blankenship, p. 7.

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;
- within 100-year floodplains; and
- on certain state-owned land.

These limits function as a partial “phased” permitting approach because they prohibit activities in areas deemed to be especially sensitive.

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 function as a partial “phased” permitting approach because they 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 be essentially arbitrary and would be unnecessary given the myriad protections recommended in this SGEIS. 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, the Department proposes to limit 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.[9]

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.[10]

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:

> *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].

[9] URS, 2009, pp. 6-1 - 6-7.
[10] URS, 2009, pp. 6-1 - 6-7.

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.[11] 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 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

[11] Smith, 2008, p. 3.

targeting the Marcellus Shale and other low-permeability gas reservoirs should a well operator make such a proposal for the Department's approval.

LPG fracturing technology is in limited use in Canada, and has only been used in Pennsylvania on several wells. In addition, there is only one known company that offers LPG hydraulic fracturing services, with limited equipment and crews, and service costs which are understood to be higher than those associated with water-based hydraulic fracturing. Therefore, at the current time, this technology is not mature enough to support development of the Marcellus Shale and other low-permeability gas reservoirs.

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].[12]

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.[13]

[12] URS, 2009, pp. 6-1 - 6-7.
[13] URS, 2009, pp. 6-1 - 6-7.

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.[14] The most significant environmentally conscious hydraulic fracturing operations and regulations to date are likely in the North Sea. Several countries have established criteria that define 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.[15]

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 contains 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 requires that applicants evaluate and, where feasible, use alternative additive products that may pose less risk to the environment, including water resources. It also provides for public disclosure of the additives, including additive MSDSs, used at each well. These requirements may 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."

[14] URS, 2009, pp. 6-1 - 6-7.
[15] 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.[1] 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.[2]

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

[1] PADEP, 2009, p. 3.
[2] PADEP, 2011, p. 9.

the proposed wellbore design for that specific well and location has been reviewed by 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.[3]

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

[3] Cabot Oil & Gas Corporation, 2009.

Department's Commissioner visited this site on June 16, 2011, and was briefed by officials from 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.[4]

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.

[4] 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.

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 environment. It was determined that blowout prevention equipment was inadequate and that certified well-control personnel were not on-site.[5]

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

[5] PADEP, 2010.

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.

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Chapter 11

Summary of Potential Impacts and Mitigation Measures

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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.

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
Water resources	Depletion of water supply in streams.	*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*			
	Reduced stream flow and degradation of a stream's best use.	*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*				Same as above.				
						Requires site-specific SEQRA review from any lake or pond.	*7.1.1.4*			
	Long-term damage to groundwater resources	*6.1.1.5*				Requires pump testing and site-specific SEQRA for groundwater withdrawal near wetlands and water wells	*7.1.1.5*			
	Cumulative surface water withdrawal impacts.	*6.1.1.7*				Addressed by individual passby flow determinations as above.	*7.1.1.6*			
	Contamination of surface and/or subsurface waters from stormwater runoff.	*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*			
						Requires application for and coverage under the General Permit before commencement of operations.	*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.	*7.1.12.1*		*17.B.1.c*	*17-4*
						Specifies setback distances from structures, surface waters, public/private water wells, and water supply springs.	*7.1.12.1*		*17.B.2.a*	*17-6..7*

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	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*		*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*			
						No well pads within 500' of a private water well, unless waived by the landowner.	*7.1.3.1*			
						Specifies continuous monitoring of refueling operations.	*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*			
						Individual crew member responsibilites must be posted for well-control. Blowout Preventers (BOPs) must be adequately sized and tested.	*7.1.3.2*			
						Affords DEC option to implement location-specific HVHF fluid management restrictions and permit conditions.	*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*			
						Identification of a spill response team and employee training on proper spill prevention and response techniques.	*7.1.3.3*			
						Requires a closed-tank system for flowback water handled at the wellpad.	*7.1.3.4*			
						Requires reporting EAF addendum on quantity, worthiness, volume, and location of tanks to accept flowback water.	*7.1.3.4*			
						Promote reuse of flowback water	*7.1.3.4*			
						Requires operators to consider less toxic alternative hydraulic fracturing fluid additives.	*8.2.1.2*			
						Limits duration of fluid impoundment after permanent/temporary suspension of drilling/hydraulic fracturing.	*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*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	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*			
						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*			
						Affords DEC the right to curtail or modify operations when a well complaint and a non-routine wellpad incident coincide.	*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*				No well pads for high-volume hydraulic fracturing within the boundaries of a primary aquifer.	*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*			
						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*			
						Requires operator to test private water wells	*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*			
						Requires departmental notification prior to surface casing cementing.	*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*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	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.	*7.1.12.1*			
						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*			
						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*				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*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
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*		*16.B.3.b,c*	*16-14..15*	Closed-tank systems must be used for flow-back of wells.	*7.3.1.2*			
						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*				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*			
						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*			
						Prohibits annular disposal of drill cuttings.	*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.	*7.1.6.1*			
						Prohibits spreading of HVHF flowback water on roads.	*7.1.6.2*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
						Requires submission of a fluid disposal plan for flowback water which specifies quality, maintenance, and monitoring of piping and conveyances.	*7.1.6.3*			
						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*			
						Requires SPDES coverage of any private wastewater treatment facility proposed to accept waste fluid.	*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*			
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*			
Floodplains	Contamination of surface waters from the release into the environment of chemical pollutants in a flood event.	*6.2*				No well pads or access roads for high-volume hydraulic fracturing permitted within 100-year floodplains.	*7.2*			
Freshwater Wetlands	Contamination of freshwater wetlands from accidental release of drilling or HF fluids, chemicals, or fuel.	*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*			
						Specifies setbacks between fuel tanks and wetlands at a mandatory 500 feet.	*7.3*			
						Requires SPOTS 10 secondary containment for any fuel tank.	*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*				Requires operator to develop and employ Best Management Practices for surface disturbance to reduce habitat impacts.	*7.4.1*			
						Restricts operations during mating and migration seasons in certain habitats	*7.4.1*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
						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*			
	Degradation of local ecosystem functions and native biological communities from the introduction of invasive species.	*6.4.1*				Requires operator diligence in exploiting accepted BMPs for removal and preventing introduction of invasive species.	*7.4.2.1*			
						Requires baseline surveying and reporting of project site for existence of invasive species.	*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*			
						Relies upon DRBC and SRBC protocols for aquatic invasive species management in their respective jurisdictions.	*7.4.2.2*			
Ecosystems and Wildlife (cont.)	Harm to local wildlife populations from the loss of habitat	*6.4.3*		*16.B.2.b*	*16-6..7*	Requires partial and final well pad reclamation.	*7.4.1*			
	Impacts to State-Owned Lands	*6.4.4*				No surface drilling allowed on specified State-owned lands.	*7.4.4*			
Air Quality	Degradation of Air Quality	*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*			
						Prohibits use of the BTEX class of compounds as additives in HVHF fluid surface impoundments.	*7.5.3.2*			
						Requires reporting of fracturing additives and public access restrictions.	*7.5.3.2*			
						Requires catalytic technology for production equipment.	*7.5.3.3*			
Greenhouse Gas Emissions	Emission of gases with Global Warming Potential due to natural gas well drilling and production.	*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*			
Naturally Occuring Radioactive Material (NORM)	Exposure of workers, the public, and the environment to harmful levels of radiation.	*6.8*				Outlines necessary monitoring work.	*7.8.2*			
						Requires NORM testing of discharged waste fluids and material in production tanks.	*7.8.2*			

RESOURCE	IMPACT	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.	MITIGATING MEASURE	dSGEIS section	dSGEIS pp.	GEIS sec.	GEIS pp.
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*		*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*			
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*		*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*		*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*				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*			
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*		*16.B.2.h*	*16-10..11*	This section will be updated after July 31, 2011.	*7.8 & 7.12*			

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New York State

DEC

Glossary

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
DOW:	Division of Water in the NYS Department of Environmental Conservation.
DMV:	(New York State) Department of Motor Vehicles.

Term	Definition
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.
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.
Flue Gas:	An exhaust gas coming out of a pipe or stack.
FMCSA:	Federal Motor Carrier Safety Administration.

Term	Definition
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.
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.
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).

Term	Definition
ITR:	Injection Timing Retard.
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
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.

Term	Definition
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.
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.
Turbidity:	Amount of suspended solids in a liquid.

Term	Definition
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.
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

Term	Definition
	well.
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

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New York State

DEC

Appendices

REVISED DRAFT
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and
High-Volume Hydraulic Fracturing to
Develop the Marcellus Shale and Other
Low-Permeability Gas Reservoirs

New York State Department of Environmental Conservation

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4	Application Form for Permit to Drill, Deepen, Plug Back or Convert a Well Subject to the Oil, Gas, and Solution Mining Regulatory Program
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[1] Updated/revised July 2011
[2] New July 2011
[3] Appendix 22 from the September 2009 dSGEIS has been replaced with a new Appendix 22.

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New York State

DEC

Appendix 1

FEMA
Flood Insurance Rate Map
Availability

Excerpted from Alpha Environmental, 2009
Updated by NYSDEC

Updated July 2011

Revised Draft
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
DUTCHESS COUNTY	AMENIA, TOWN OF	11/15/1989
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
MONROE COUNTY	GATES, TOWN OF	08/28/2008
MONROE COUNTY	GREECE, TOWN OF	08/28/2008
MONROE COUNTY	HAMLIN, TOWN OF	08/28/2008
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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 (	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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

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Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
SULLIVAN COUNTY	BLOOMINGBURG, VILLAGE 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	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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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)

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)
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

TABLE 3.4

Summary of FEMA Flood Insurance Rate Map (FIRM) Availability

County	Community Name	Current FIRM Effective Date
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)

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New York State

DEC

Appendix 2

1992 SEQRA Findings Statement on the GEIS on the Oil, Gas and Solution Mining Regulatory Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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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.

<u>Other SEQR Considerations</u>

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. <u>Project scope</u> - 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. <u>Size of Project</u> - The size of the project will continue to be defined as the surface acreage affected by development.

3. <u>Lead Agency</u> - In 1981, the Legislature gave exclusive authority to the Department to regulate the oil, gas and solution mining industries under ECL Section 23-0303(2). Thus, only the Department has jurisdiction to grant drilling permits for wells subject to Article 23, except within State parklands. To the extent practicable, the Department will actively seek lead agency designation consistent

with the general intent of Chapter 846 of the Laws of 1981.

4. Coastal Resources - On the program specific EAF that must accompany every drilling permit application, the applicant must indicate whether the proposed well is in a legally designated New York State Coastal Zone Management (CZM) Area. Neither the policies in the New York State CZM Plan, nor the provisions of individual Local Waterfront Revitalization Plans (LWRP's) are covered in the GEIS. Once an LWRP is adopted by a community, it is a legally binding part of the New York State CZM Plan. The Department cannot issue any drilling permit unless it is consistent with the New York State CZM Plan to the "maximum extent practicable."

CERTIFICATION OF FINDINGS TO ADOPT THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met;

2. Consistent with the social, economic and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement, and

3. Consistent with social, economic and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

Gregory H. Sovas — Sept. 29, 1992

Director — Date
Division of Mineral Resources

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New York State

DEC

Appendix 3

Supplemental SEQRA Findings Statement on Leasing of State Lands for Activities Regulated Under the Oil, Gas and Solution Mining Law

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SEQR File No.

P0-009900-00046

Supplemental
Findings Statement

Pursuant to the State Environmental Quality Review Act (SEQR) of the Environmental Conservation Law (ECL) and the SEQR Regulations 6NYCRR Part 617, the New York State Department of Environmental Conservation makes the following supplemental findings on the Final Generic Environmental Impact Statement (GEIS) on the Oil, Gas and Solution Mining Regulatory Program.

Name of Action

Adoption of supplemental findings on leasing of state lands for activities regulated under the Oil, Gas and Solution Mining Law (ECL Article 23).

Description and Background

In early 1988, the Department of Environmental Conservation released the Draft GEIS on the Oil, Gas and Solution Mining Regulatory Program. The Draft GEIS comprehensively reviewed the environmental impacts of the Department's program for regulating the siting, drilling, production and plugging and abandonment of oil, gas, underground gas storage, solution mining, brine disposal, geothermal and stratigraphic test wells. The findings statement issued on the Draft and Final GEIS in September, 1992 neglected to specifically mention DEC's program for leasing of State lands for these resource development activities.

Prior to adoption of the GEIS, proposed lease sales underwent a segmented review. Segmented reviews are permitted under certain circumstances if they are no less protective of the environment. This is true given the highly speculative nature of oil and gas leasing practices:

- It is impractical to review the potential environmental impacts of development activities at the leasing stage. Information on the placement of well sites is not generally known, even by the lessee. Not until a company successfully obtains a lease does it invest time and money in preparing the exploration and development plans that will be submitted to the Department for approval if the lessee wishes to commence operations.

- Most of the land leased will never be directly affected by development activities. Based on a 15 year record of the State's leasing program, less than one percent of all the State land leased has been subject to any direct impact.

- When the lessee does decide on a proposed well site on a State lease, the lessee must obtain a site-specific drilling permit from the Department. With eve well drilling permit application the Department requires: 1) a program-specific Environmental Assessment Form, 2) a plat (map) showing the proposed well location and support facilities, and 3) a pre-drilling site inspection that allows the Department to :
  - reliably determine potential environmental problems; and

- select appropriate permit conditions for mitigating potential environmental impacts.

- Possession of a lease does not a priori grant the right to drill on a lease. Nor is the lessee in any way guaranteed approval for their first-choice drilling location. Clauses included in the lease inform the lessee that any surface disturbing activities must receive Department review and approval prior. to their commencement. Leases also contain clauses recommended by other State agency staff that are necessary for protection of fish, wildlife, plant, land, air, wetlands, water and cultural resources on the leased parcels.

SEOR Determination of Significance

The Department has determined that the act of leasing State lands for activities regulated under ECL Article 23 does not have a significant environmental impact. This determination is supported by the facts listed above.

SEOR Review Procedures

Department staff will no longer make Determinations of Significance and Negative or Positive Declarations under SEQR for leases on State lands for activities regulated under ECL Article 23 at the time that the lease is granted; SEQR reviews will continue to be done as needed for site-specific development.

CERTIFICATION OF SUPPLEMENTAL FINDINGS ON THE FINAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM

Having considered the Draft and Final GEIS, and having considered the preceding written facts and conclusions relied upon to meet the requirements of 6NYCRR Part 617.9, this Supplemental Statement of Findings certifies that:

1. The requirements of 6NYCRR Part 617 have been met.

2. Consistent with the social, economic, and other essential considerations from among the reasonable alternatives thereto, the action approved is one which minimizes or avoids adverse environmental effects to the maximum extent practicable; including the effects disclosed in the environmental impact statement.

3. Consistent with the social, economic, and other essential considerations, to the maximum extent practicable, adverse environmental effects revealed in the environmental impact statement process will be minimized or avoided by incorporating as conditions to the decision those mitigative measures which were identified as practicable.

4. Consistent with the applicable policies of Article 42 of the Executive Law, as implemented by 19 NYCRR 600.5, this action will achieve a balance between the protection of the environment and the need to accommodate social and economic considerations.

/S/ April 19, 1993

Gregory H. Sovas, Director
Division of Mineral Resources

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New York State

DEC

Appendix 4

Application Form for Permit to Drill, Deepen, Plug Back or Convert A Well Subject to the Oil, Gas and Solution Mining Regulatory Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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85-12-5 (10/07)

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

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	NUMBER OF ACRES IN UNIT

7½ MINUTE QUAD NAME	QUAD SECTION	PROPOSED TARGET FORMATION

LOCATION DESCRIPTION

	TVD	TMD	Decimal Latitude (NAD83)	Decimal Longitude (NAD83)
Surface	0'	0	☐☐.☐☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐☐
Top of Target Interval			☐☐.☐☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐☐
Bottom of Target Interval			☐☐.☐☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐☐
Bottom Hole			☐☐.☐☐☐☐☐☐☐	☐☐.☐☐☐☐☐☐☐

PROPOSED WELL DATA

WELL TYPE (check one)

☐ Oil Production ☐ Gas Production ☐ Brine ☐ Storage
☐ Injection ☐ Brine Disposal ☐ Geothermal ☐ Stratigraphic
☐ Other ______

PLANNED TOTAL DEPTH

TVD ______ ft.
TMD ______ ft.
Kickoff ______ TMD

PLANNED DATE OF COMMENCEMENT OF OPERATIONS

SURFACE ELEVATION (check how obtained)

______ ft. ☐ Surveyed ☐ Topo Map ☐ Other ______

TYPE TOOLS

☐ Cable ☐ Rotary

PLANNED DRILLING FLUID

☐ Air ☐ Water ☐ Mud

NAME OF PLANNED DRILLING CONTRACTOR (as registered with the Division)	TELEPHONE NUMBER (include area code)

ON ATTACHED SHEET GIVE DETAILS FOR EACH PROPOSED CASING STRING AND CEMENT JOB INCLUDING BUT NOT LIMITED TO: Bit size, casing size, casing weight and grade, TVD and TMD of casing set, scratchers, centralizers, cement baskets, sacks of cement, class of cement, cement additives with percentages or pounds per sack, estimated TVD and TMD of the top of cement, estimated amount of excess cement and waiting-on-cement time.

FOR DIRECTIONAL OR SIDETRACK WELLS ALSO INCLUDE A WELL BORE DIAGRAM SHOWING THE LOCATION OF THE ITEMS INCLUDED IN THE ABOVE REFERENCED DETAILS.

DEPARTMENT USE ONLY

BOND NUMBER	
API WELL IDENTIFICATION NUMBER 31-	
RECEIPT NUMBER	
DATE ISSUED	

APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT

WELL NAME	WELL NUMBER	NAME OF OWNER

COMMENTS:

AFFIRMATION AND ACKNOWLEDGMENT

A. For use by individual:

By the act of signing this application:

(1) I affirm under penalty that the information provided in this application is true to the best of my knowledge and belief; and that I possess the right to access property, and drill and/or extract oil, gas, or salt, by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) I acknowledge that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, I accept full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agree to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

____
Printed or Typed Name of Individual

______________________________ ______________
Signature of Individual Date

B. For use by organizations other than an individual:

By the act of signing this application:

(1) I affirm under penalty of perjury that I am ______________________________ (title) of ______________________________ (organization); that I am authorized by that organization to make this application; that this application was prepared by me or under my supervision and direction; and that the aforenamed organization possesses the right to access property, and drill and/or extract oil, gas, or salt by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) ______________________________ (organization); acknowledges that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, it accepts full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agrees to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, from suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

____
Printed or Typed Name of Authorized Representative

______________________________ ______________
Signature of Authorized Representative Date

New York State

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Appendix 5

Environmental Assessment Form (EAF) For Well Permitting

Revised Draft
Supplemental Generic Environmental Impact Statement

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85-16-5 (1/07)--10b

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

ENVIRONMENTAL ASSESSMENT FORM

Attachment to Drilling Permit Application

WELL NAME AND NUMBER

NAME OF APPLICANT | BUSINESS TELEPHONE NUMBER ( )

ADDRESS OF APPLICANT

CITY/P.O. | STATE | ZIP CODE

DESCRIPTION OF PROJECT (Briefly describe type of project or action)

PROJECT SITE IS THE WELL SITE AND SURROUNDING AREA WHICH WILL BE DISTURBED DURING CONSTRUCTION OF SITE, ACCESS ROAD, and PIT AND ACTIVITIES DURING DRILLING AND COMPLETION AT WELLHEAD.

(PLEASE COMPLETE EACH QUESTION--Indicate N.A., if not applicable)

LAND USE AND PROJECT SITE

1. Project Dimensions. Total Area of Project Site ________ sq. ft.
   Approximate square footage for items below:

		During Construction (sq. ft.)	After Construction (sq. ft.)
a. Access Road	(length x width)	________	________
b. Well Site	(length x width)	________	________

2. Characterize Project Site Vegetation and Estimate Percentage of Each Type Before Construction:

   ______ % Agricultural (cropland, hayland, pasture, vineyard, etc.) ______ % Forested ______ % Wetlands

   ______ % Meadow or Brushland (non agricultural) ______ % Non vegetated (rock, soil, fill)

3. Present Land Use(s) Within ¼ Mile of Project (Check all that apply)

   ☐ Rural ☐ Suburban ☐ Forest ☐ Urban ☐ Agricultural ☐ Commercial ☐ Park/Recreation
   ☐ Industrial ☐ Other ________

4. How close is the nearest residence, building, or outdoor facility of any type routinely occupied by people at least part of the day? ________ ft.

   Describe ________

ENVIRONMENTAL RESOURCES ON/NEAR PROJECT SITE

5. The presence of certain environmental resources on or near the project site may require additional permits, approvals or mitigation measures--Is any part of the well site or access road located:

   a. Over a primary or principal aquifer? ☐ Yes ☐ No ☐ Not Known
   b. Within 2,640 feet of a public water supply well? ☐ Yes ☐ No ☐ Not Known
   c. Within 150 feet of a surface municipal water supply? ☐ Yes ☐ No ☐ Not Known
   d. Within 150 feet of a lake, stream, or other public surface water body? ☐ Yes ☐ No ☐ Not Known
   e. Within an Agricultural District? ☐ Yes ☐ No ☐ Not Known
   f. Within a land parcel having a Soil and Water Conservation Plan? ☐ Yes ☐ No ☐ Not Known
   g. In a 100 year flood plain? ☐ Yes ☐ No ☐ Not Known
   h. In a regulated wetland or its 100 foot buffer zone? ☐ Yes ☐ No ☐ Not Known
   i. In a coastal zone management area? ☐ Yes ☐ No ☐ Not Known
   j. In a Critical Environmental Area? ☐ Yes ☐ No ☐ Not Known
   k. Does the project site contain any species of animal life that are listed as threatened or endangered? ☐ Yes ☐ No ☐ Not Known

      If yes, identify the species and source of information ________
   l. Will proposed project significantly impact visual resources of statewide significance? ☐ Yes ☐ No ☐ Not Known

      If yes, identify the visual resource and source of information ________

CULTURAL RESOURCES

6. Are there any known archeological and/or historical resources which will be affected by drilling operations? ☐ Yes ☐ No ☐ Not Known

7. Has the land within the project area been previously disturbed or altered (excavated, landscaped, filled, utilities installed)? ☐ Yes ☐ No ☐ Not Known

If answer to Number 6 or 7 is yes, briefly descrbe ______________________________

EROSION AND RECLAMATION PLANS

8. Indicate percentage of project site within: 0-10% slope ______ % 10-15% slope ______ % greater than 15% slope ______ %

9. Are erosion control measures needed during construction of the access road and well site? ☐ Yes ☐ No ☐ Not Known

If yes, describe and/or sketch on attached photocopy of plat ______________________________

10. Will the topsoil which is disturbed be stockpiled for reclamation use? ☐ Yes ☐ No

11. Does the reclamation plan include revegetation? ☐ Yes ☐ No

If yes, what plant materials will be used? ______________________________

12. Does the reclamation plan include restoration or installation of surface or subsurface drainage features to prevent erosion or conform to a Soil and Water Conservation Plan? ☐ Yes ☐ No

If yes, describe ______________________________

ACCESS ROAD SITING AND CONSTRUCTION

13. Are you going to use existing or common corridors when building the access road? ☐ Yes ☐ No
Locate access road on attached photocopy of plat.

DRILLING

14. Anticipated length of drilling operations? ________ days.

WASTE STORAGE AND DISPOSAL

15. How will drilling fluids and stimulation fluids:

a. Be contained? ______________________________

b. Be disposed of? ______________________________

16. Will production brine be stored on site? ☐ Yes ☐ No

If yes:
How will it be stored? ______________________________

How will it be disposed of? ______________________________

17. Will the drill cuttings and pit liner be disposed of on site? ☐ Yes ☐ No

If yes, expected burial depth? ______________ feet

ADDITIONAL PERMITS

18. Are any additional State, Local or Federal permits or approvals required for this project? ☐ Yes ☐ No

	Date Application Submitted	Date Application Received
Stream Disturbance Permit (DEC)		
Wetlands Permit (DEC or Local)		
Floodplain Permit (DEC or Local)		
Other ______		

PREPARER'S SIGNATURE	DATE
NAME/TITLE (Please print)	
REPRESENTING	

Suggested Sources of Information for Division of Mineral Resources Environmental Assessment Form

3. LAND USE
Sources: Local Planning Office
Town Supervisor's Office
Town Clerk's Office

5a. PRIMARY OR PRINCIPAL AQUIFER
Sources: Local unit of government
NYS Department of Health
NYSDEC, Division of Water--Regional Office
Availability of Water from Aquifers in New York State--United States Geological Survey
Availability of Water from Unconsolidated Deposits in Upstate New York--United States Geological Survey

5b. PUBLIC WATER SUPPLY
Sources: Local unit of government
NYS Department of Health
NYS Atlas of Community Water Systems Sources, NYS Department of Health, 1982
Atlas of Eleven Selected Aquifers in New York State, United States Geological Survey, 1982

5c. AGRICULTURAL DISTRICT INFORMATION
Sources: Cooperative Extension
DEC, Division of Lands and Forests
NYS Department of Agriculture and Markets
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5f. SOIL AND WATER CONSERVATION PLAN
Sources: Landowner
County Soil and Water Conservation District Office

5g. 100 YEAR FLOOD PLAIN
Sources: DEC Division of Water
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5h. WETLANDS
Sources: DEC, Division of Fish and Wildlife--Regional Office
DEC, Division of Mineral Resources--Regional Office

5i. COASTAL ZONE MANAGEMENT AREAS
Sources: Local unit of government
NYS Department of State, Coastal Management Program
DEC, Division of Water (maps)
DEC, Division of Environmental Permits--Regional Office

5k. THREATENED OR ENDANGERED SPECIES
Sources: DEC, Natural Heritage Program--Albany
DEC, Division of Environmental Permits--Regional Office

6. ARCHEOLOGICAL OR HISTORIC RESOURCES
Sources: NYS Office of Parks, Recreation and Historic Preservation circles and squares map
DEC, Division of Environmental Permits--Regional Office

18. ADDITIONAL PERMITS NEEDED
Sources: DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office
NYS Office of Business Permits

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Appendix 6

PROPOSED
Environmental Assessment Form
Addendum

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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
- 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.

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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New York State

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Appendix 8

Casing & Cementing Practices Required for All Wells in NY

Revised Draft
Supplemental Generic Environmental Impact Statement

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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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New York State

DEC

Appendix 9

EXISTING
Fresh Water Aquifer Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers

Revised Draft
Supplemental Generic Environmental Impact Statement

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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.**

New York State

DEC

Appendix 10

PROPOSED
Supplementary Permit Conditions
For High-Volume Hydraulic Fracturing

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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 water-well, 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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New York State

DEC

Appendix 11

Analysis of Subsurface Mobility of Fracturing Fluids

Excerpted from ICF International, Task 1, 2009

Revised Draft
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.

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[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

$$h_{p1} = \frac{110\% \times d_1 \times [0.75(150\,pcf - 62.4\,pcf) + 62.4\,pcf]}{62.4\,pcf} = 2.26 d_1 \qquad (12)$$

Equation (6) thus becomes

$$i = \frac{(d_2 - d_1) + 2.26 d_1}{|d_1 - d_2|} = \frac{d_2 + 1.26 d_1}{|d_1 - d_2|} \qquad (13)$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

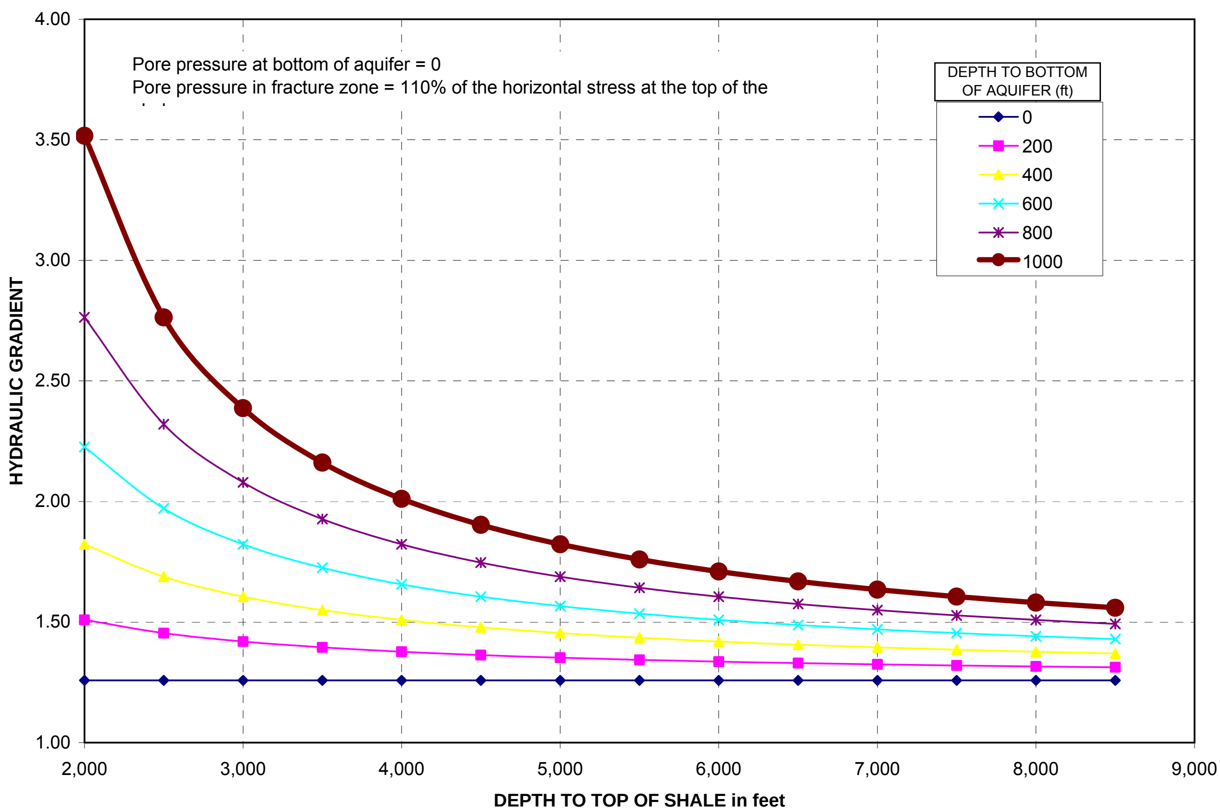

Figure 1: Average hydraulic gradient during fracturing

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

[137] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.[138] During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \tag{10}$$

where v = seepage velocity
k = hydraulic conductivity
n = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.[139] Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

Table 4: Hydraulic conductivity of rock masses[140]

Material	Minimum k	Maximum k
Intact Sandstone	1E-8 cm/sec	1E-5 cm/sec
Sandstone rock mass	1E-9 cm/sec	1E-1 cm/sec
Intact Shale	1E-11 cm/sec	1E-9 cm/sec
Shale rock mass	1E-9 cm/sec	1E-4 cm/sec

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

[138] Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.
[139] Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.
[140] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.[141] Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

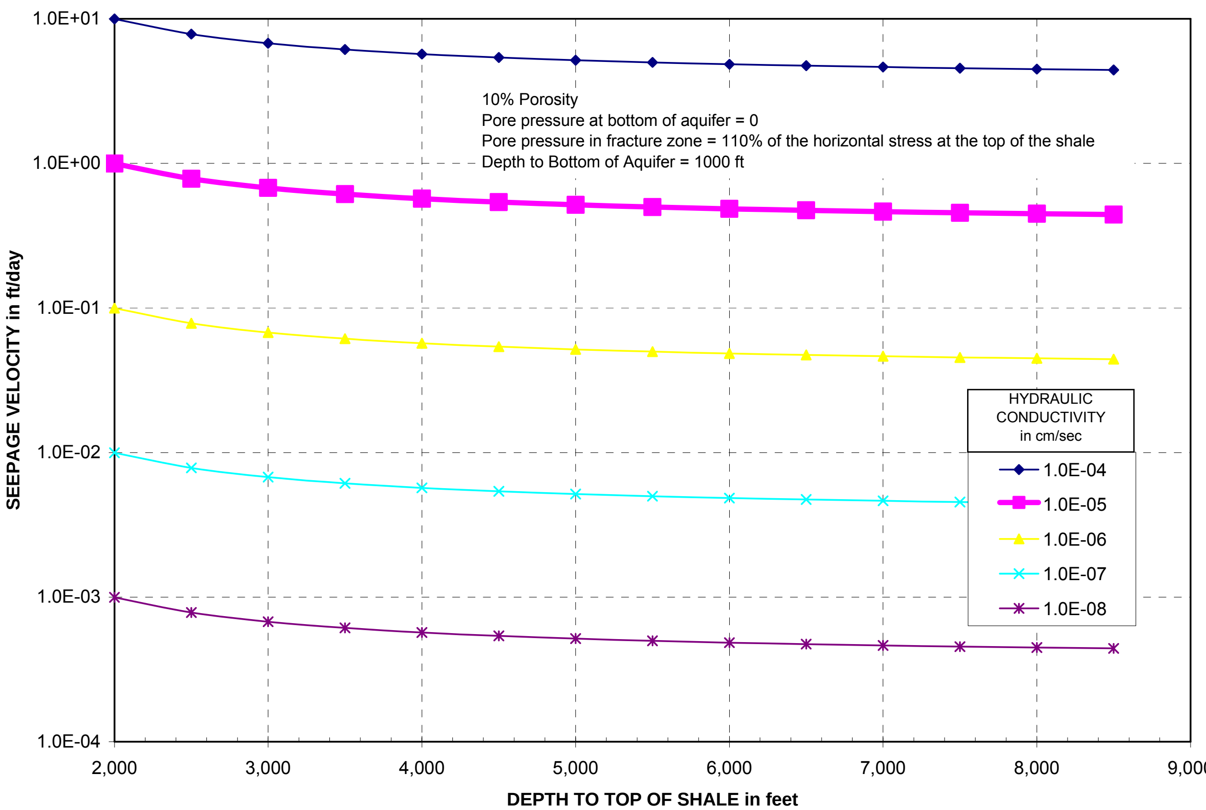

Figure 2: Seepage velocity as a function of hydraulic conductivity

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

[141] DOE, Office of Fossil Energy, 2009. *State Oil and National Gas Regulations Designed to Protect Water Resources*, May 2009.

1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where t = required travel time

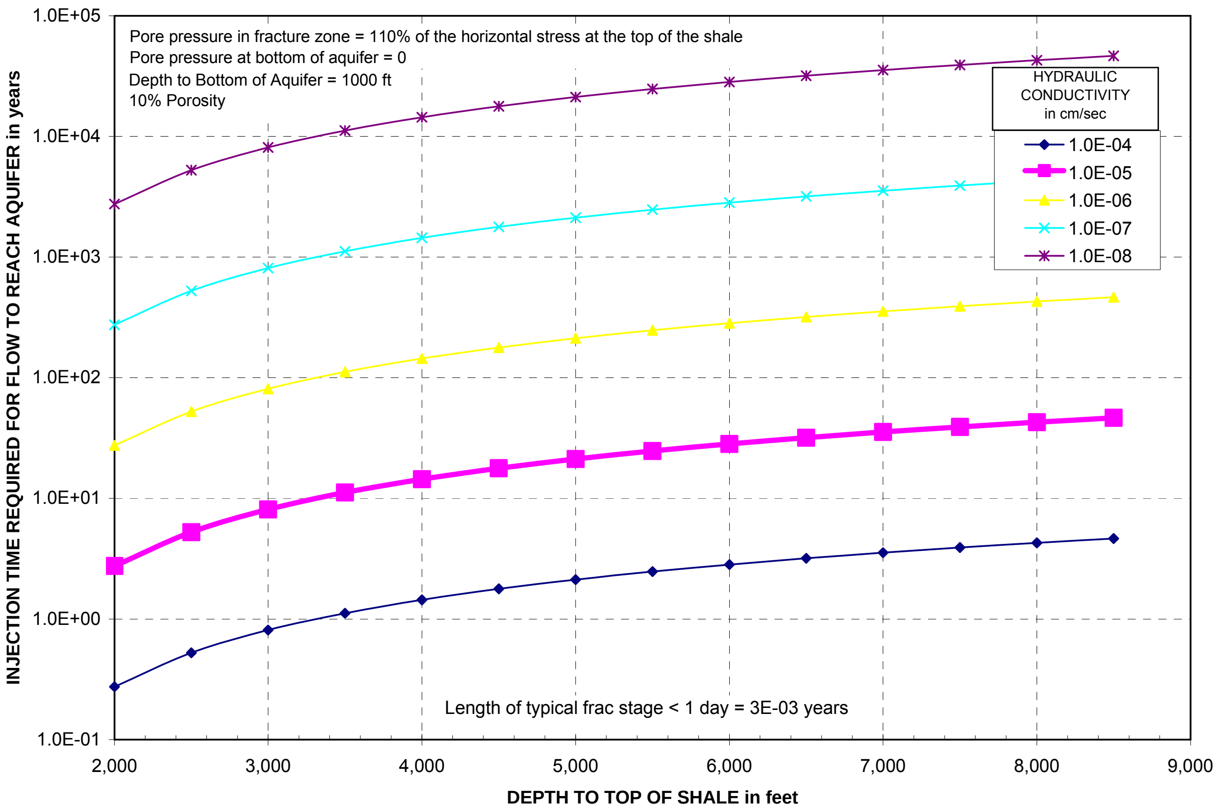

Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity

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.

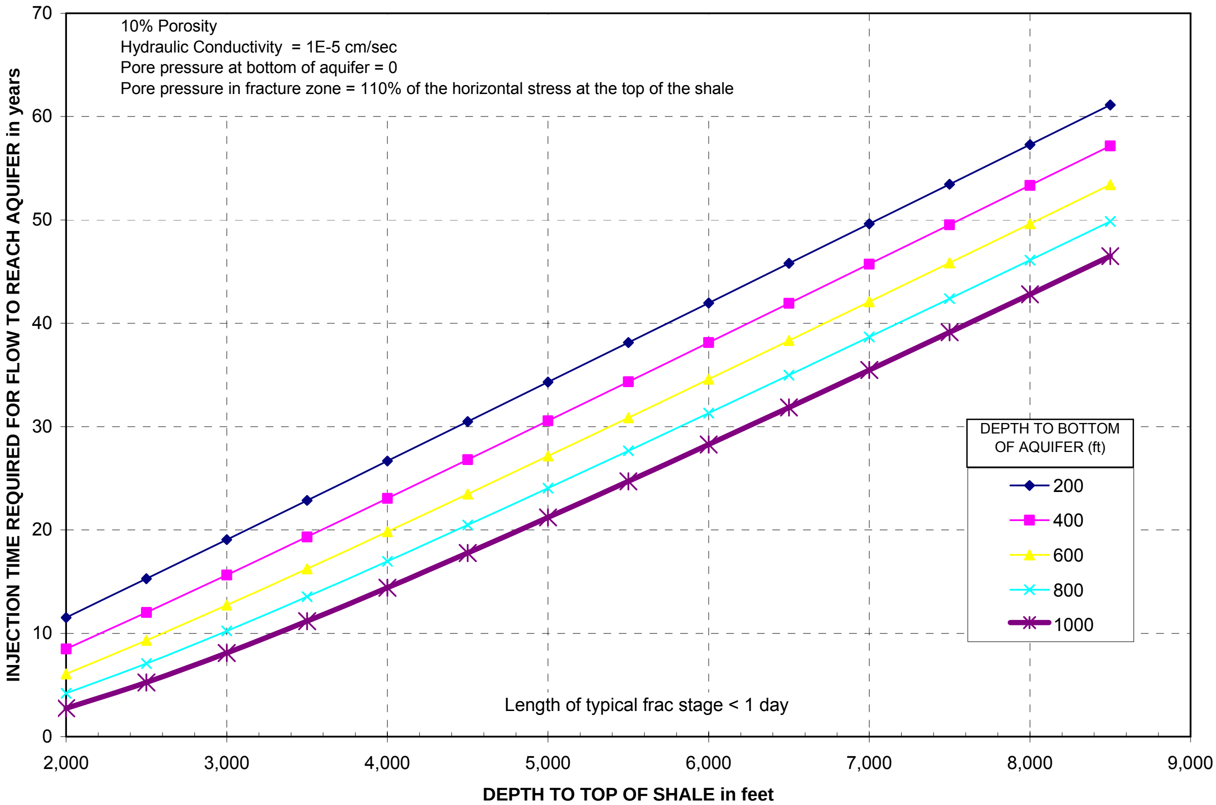

Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth

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.

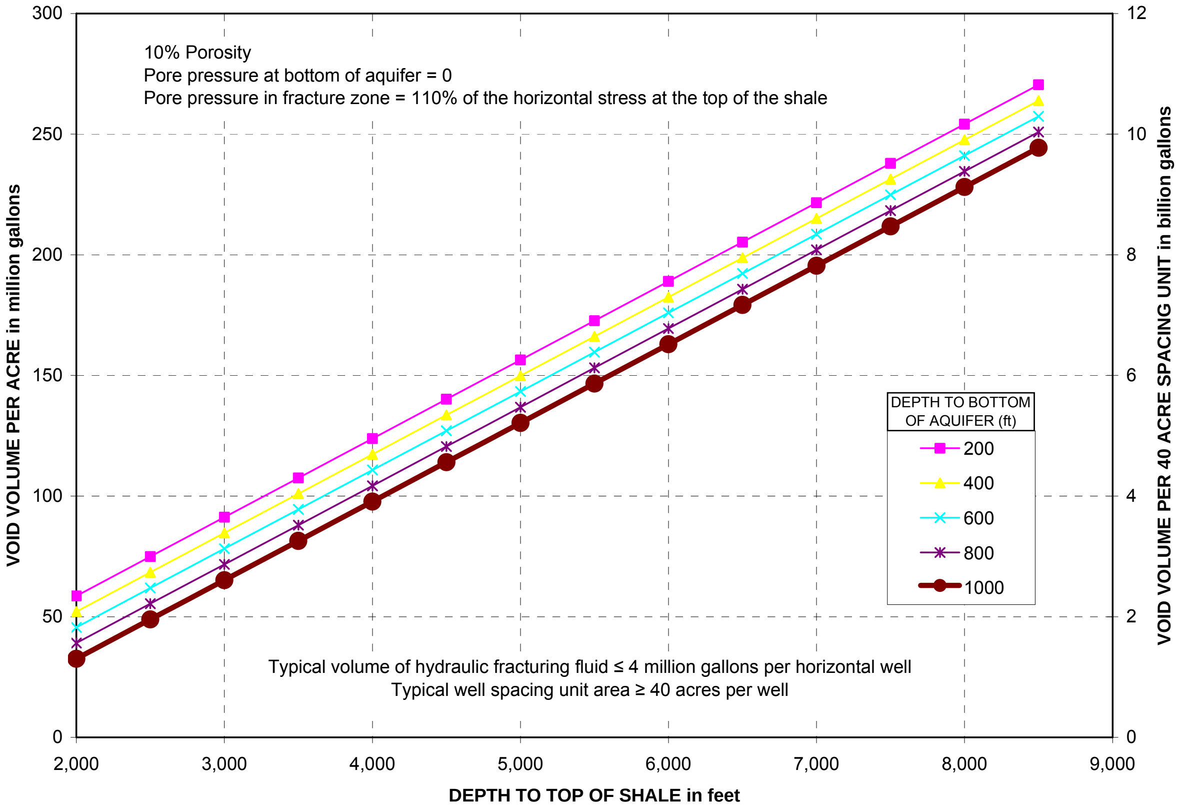

Figure 5: Comparison of void volume to frac fluid volume

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]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \tag{13}$$

where K_{ow} = octanol-water partition coefficient
S_w = solubility in water at 20ºC in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

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147 Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

1.2.7 Conclusions

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

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

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

New York State

DEC

Appendix 12

Beneficial Use Determination (BUD) Notification Regarding Road Spreading

Revised Draft
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

DEC

Appendix 13

Radiological Data - Production Brine from NYS Marcellus Wells

Revised Draft
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

DEC

Appendix 14

Department of Public Service
Environmental Management & Construction
Standards and Practices – Pipelines

Revised Draft
Supplemental Generic Environmental Impact Statement

ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION

STANDARDS AND PRACTICES

CHECK-OFF LIST: PART III

PIPELINE

New York State

DEC

Appendix 15

Hydraulic Fracturing –
15 Statements from Regulatory Officials

Revised Draft
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:

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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.

Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009

Modern Shale Gas Development in the United States: A Primer

EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

Ohio Department of Natural Resources

TED STRICKLAND, GOVERNOR

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May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a defective primary cement job on the production casing, which was further complicated by operator error. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection
Rachel Carson State Office Building
P.O. Box 8555
Harrisburg, PA 17105-8555
June 1, 2009

Bureau of Watershed Management 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

Oil Conservation Division
1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3440 • Fax (505) 476-3462 • www.emnrd.state.nm.us/OCD

STATE OIL AND GAS BOARD OF ALABAMA

OIL AND GAS BOARD
James H. Griggs, Chairman
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S. Marvin Rogers, Counsel

420 Hackberry Lane
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Phone (205)349-2852
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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.

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

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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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New York State

DEC

Appendix 16

Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

Revised Draft
Supplemental Generic Environmental Impact Statement

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Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

New York State's air regulation 6 NYCRR Part 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 Part 227-2 include emission limits, stack testing, and annual tune-ups, among others. Many facilities whose potential to emit (PTE) air pollutants would make them susceptible to NO_x RACT requirements can limit, or "cap", their emissions using the limits within the New York State Department of Environmental Conservation's (DEC) Air Emissions Permits applicability thresholds to avoid this regulation.

New York State has two different major source thresholds for 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 DEC Regional Office as soon as possible. In this case the facility would also be subject to Title V, and a Title V air permit application must be prepared and submitted.

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New York State

DEC

Appendix 17

Applicability of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities – Final Rule

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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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 HAP at a rate of 25 tons or more per year. An area source of HAP emissions is a source that is not a major source.

Available emissions data show that several HAP, which are formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAP which have been measured in emission tests conducted on natural gas fired and diesel fired RICE include: 1,1,2,2-tetrachloroethane, 1,3-butadiene, 2,2,4-trimethylpentane, acetaldehyde, acrolein, benzene, chlorobenzene, chloroethane, ethylbenzene, formaldehyde, methanol, methylene chloride, n-hexane, naphthalene, polycyclic aromatic hydrocarbons, polycyclic organic matter, styrene, tetrachloroethane, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have been measured are: cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Although numerous HAP may be emitted from RICE, only a few account for essentially all of the mass of HAP emissions from stationary RICE. These HAP are: formaldehyde, acrolein, methanol, and acetaldehyde. EPA is proposing to limit emissions of HAP through emissions standards for formaldehyde for non-emergency four stroke-cycle rich burn (4SRB) engines and 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 O2, 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

New York State

DEC

Appendix 18

Definition of Stationary Source or Facility for the Determination of Air Permit Requirements

Revised July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

Definition of Stationary Source or Facility
for the Determination of Air Permit Requirements

Summary

NYSDEC must determine the applicability of air permitting regulations and requirements to natural gas drilling activities in the Marcellus Shale formation. Specifically, NYSDEC 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, NYSDEC 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, DEC 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 SGEIS, 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, 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 activity,

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[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.

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, DEC 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," DEC 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 consideration, it is not an express element of the actual three-part test set forth in regulation, and in the context of oil

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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

and gas infrastructure, it may have reduced relevance to an agency determination"[14] Nevertheless, to be thorough, DEC staff will evaluate the nature of the relationship between the facilities and the degree of interdependence between them to determine whether the non-contiguous emissions points should be aggregated.[15]

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 a particular source category.

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 "common control" [21]: 1) Whether control has been

[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 Quslity, 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
[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

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, DEC 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?
    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. DEC 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

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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

of NESHAP applicability. Guided by EPA's three source determination criteria and the underlying recommendation to use case specific facts, DEC will consider all pertinent information on a case-by-case basis in arriving at its conclusions during source permitting review.

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New York State

DEC

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

New July 2011

Revised Draft
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)	NOx (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 NOx + HC standard
Tier 3	2006	0.15	2.7	0.3	3.0 g/bhp*hr NOx + HC standard
Tier 4 interim	2011	0.01	1.35	0.14	NOx 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 apportions 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

Standard	Initial Year	PM (g/bhp*hr)	NOx (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 NOx + HC standard
Tier 4 interim	2011	0.075	2.6	0.3	
Tier 4 final	2015	0.03	2.6	0.14	

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 do not force the use of NO_x aftertreatment.

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. Technologies include: Diesel Oxidation Catalysts which oxidize hydrocarbons and carbon based particulate matter, Continuously Regenerating Diesel Particulate Filters or “Traps” (CRDPF) where particulate matter is collected and oxidized, and Selective Catalytic Reduction (SCR) which uses ammonia (usually supplied as urea) or “NO_x absorbers” to reduce NO_x emissions. Although in the past EPA had identified the NO_x absorbers as a promising technology, more recently it has not been proven to be so. Its use has been limited to certain light duty trucks and cars, but it has not been applied to the size class of the fracking engines. In addition, the “lean NO_x Catalyst” system noted by EPA to have a certain 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 (2).

[1] Listing of this manufacturer does not imply any form of endorsement. Other manufacturers could provide similar aftertreatment information.

Table 3 Exhaust Aftertreatment Retrofit Effectiveness

Technology	Abbreviation	PM Emissions Reduction (%)	NOx 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 (3). The development of Johnson Matthey's retrofit system is described by Conway and coworkers (4). 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 market for large nonroad diesel engine exhaust aftertreatment. There are other NO_x control technologies; however their applicability appears to be limited to smaller engines, such as those in light duty vehicles. Although the engines used in drilling and hydraulic fracturing are defined in regulation as nonroad mobile engines, they are physically static during drilling or hydraulic fracturing. They also have a relatively steady duty cycle, without the frequent transient operation seen in motor vehicles. Thus, the engineering and operational challenges associated with exhaust aftertreatment retrofits should be reduced in comparison to highway vehicles. It should also be easier to achieve higher NO_x reduction levels with SCR.

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) (3) (4).

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 our Marcellus Shale evaluation due to the new 1 hour NO_2 standard and specific emission factor estimates are necessary to assure that modeling results account for the NO_2 portion of the emissions.

Conventional information has been 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 NOx emissions from highway vehicles. The most comprehensive summary is by Grice, et al (5), 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% (5). EURO II engines, which have no exhaust aftertreatment, have a 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 and coworkers 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 a 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 (6) and exhaust temperature (7). 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 (8), (9), (10). 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 on 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 0.35%. 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 (2). 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 (3). 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 and coworkers, 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 NOx 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, (11) (12), 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 One and Two. In cases where a NOx + HC standard was promulgated, the standard is apportioned 90% NO_x, 10% HC. Effectiveness of exhaust aftertreatment retrofits are based on Table Three. 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 NOx emissions is presented.

Table 5 Emissions Factors for Engines between 600 and 750 Horsepower

Air Drilling Engines

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NOx (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

Standard	Effective Year	Retrofit	PM (g/bhp*hr)	NOx (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

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. NOx 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. A key 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 NOx aftertreatment.

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11. *Simulation of Automotive NH3 Oxidation Catalysts Based on Pre-computed Rate Data from Mechanistic Surface Kinetics.* **Votsmeier, M., et al.** 2010, Catalysis Today, Vol. 151, pp. 271-277.

12. *NH3-Slip Catalytsts: Experiments Versus Mechanistic Modeling.* **Scheuer, A., et al.** 2009, Topics in Catalysis, Vol. 52, pp. 1847-1851

13. **Barnes, David L.** *Nonroad Engine Emissions Rate estimates.xlsx.* March 8, 2011.

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Appendix 18B

Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selected Catalytic Reduction (SRC) Treatment

1. Introduction

In order to mitigate modeled exceedences of the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO_2) the SGEIS has recommended that the hydraulic fracturing engines (and tier 1 drilling engines) used in the development of gas production wells in the Marcellus formation in New York State must be equipped with post-combustion controls. Selective catalytic reduction (SCR) is the recommended technology for addressing NO_2 concerns (see Appendix 18A). SCR is a proven technology for reducing oxides of nitrogen (NO_x) emissions from combustion sources. This technology involves the use of a urea solution (32.5 percent urea) which converts NO_x to nitrogen gas on a catalyst.

To determine the viability of the SCR control use for the hydraulic fracturing engines in terms of the associated costs, an approximate estimate of mitigation cost is presented in this appendix. It should be noted that these estimates are not necessarily representative of the actual costs which industry will experience. The purpose of these estimates is to determine the cost per ton of NOx removal for a relative comparison to cost thresholds used by the Department for NOx RACT purposes at stationary sources.[1] In addition, it should be noted that any reference to specific manufacturers (in footnotes) does not constitute an endorsement, but merely presents the specific information source.

First, an estimate is developed regarding how many jobs and how many hours a hydraulic fracturing engine could be used each year. In the third section, the costs of installing and operating an SCR system on a typical 2250 hp hydraulic fracturing engine are presented. In the fourth section the cost per ton of NO_x removed from the exhaust stream is compared with the NO_x RACT cost threshold used for stationary sources. A summary of the findings of this investigation are presented in the final section.

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).[2] 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.[3] Therefore, a hydraulic fracturing engine could be used up to 2,000 hours per year at their maximum load:

(20 jobs/year)(10 days/job)(5 fracs/day)(2 hours/frac) = 2,000 hours/year

[1] Hydraulic fracturing engines are considered nonroad sources.
[2] "NY DEC SGEIS Information Requests", ALL Consulting, September 16, 2010, page 39.
[3] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, page 9.

3. Reduction of Oxides of Nitrogen and Costs

Selective catalytic reduction (SCR) is a proven technology for reducing NO_x emissions and the Department is assuming that this technology will be preferentially used to reduce NO_x emissions from hydraulic fracturing engines. 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 $16 per hp.[4] It was assumed that the scale-up factor was one. Installation costs were assumed to be 60 percent of the system cost.[5] 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 $60,480 as detailed below:

System Cost:	$36,000
Installation:	$21,600
Taxes:	$ 2,880
Total:	$60,480

As noted previously, these costs are used in order to estimate the "cost effectiveness" value for the purpose of comparisons to "thresholds" used by the Department.

Periodic Costs

The periodic costs considered by the Department were for replacing SCR catalysts every five years.[6] It was assumed that the replacement costs were seven (7) percent of the system costs[7] and installation 60 percent of the replacement cost. The periodic costs (at year 5) were estimated to be $4,032 as detailed below:

Catalyst Replacement:	$2,520
Installation:	$1,512
Total:	$4,032

Annual Costs

Reagent (urea) costs are the primary costs in this category. The quantity of reagent used depends upon the amount of NO_x coming from the engine. The control efficiency for SCRs was assumed

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[4] The cost for a Volvo SCR is reported to be $9600 ("2010-Compliant Diesel Truck Price Increases Out – The Changing Paradigm", Jay Thompson, www.glgroup.com/NewsWatchPrefs/Print.aspx?pid=42461, August 14, 2009). Further, it was assumed the power rating for a typical truck is 600 hp.

[5] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, pages 168-169.

[6] E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008.

[7] 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..

to be 90 percent for engines. The emission rates factored into this analysis are presented in Table 1 (see Appendix 18B). Further, it was assumed that hydraulic fracturing engines will be operated at 50 percent of capacity.[8] The urea requirement for each pound of NO_x treated in an SCR is 0.2088 gallons.[9]

Table 1: NO_x Emission Rates for Tier 2, Interim 4 (I4) and 4 Hydraulic Fracturing Engines

Tier #	NO_x (without control) [10] (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.[11]

In addition to the reagent requirements, annual insurance costs were estimated to be one (1) percent of the system cost[12] and maintenance costs were assumed to be six (6) percent of the system cost.[13] A summary of the annual costs is presented below:

	Tier 2	Tier I4	Tier 4
Reagent:	\$14,800	\$9,200	\$8,900
Insurance:	\$ 600	\$ 600	\$ 600
Maintenance:	\$ 3,600	\$3,600	\$3,600
Total:	\$19,000	\$13,400	\$13,100

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.

4. Cost Effectiveness Analysis

The cost effectiveness of applying SCR controls on Tier 2, I4 and 4 hydraulic fracturing engines is presented in Table 2. By comparison, the current cost threshold for the NO_x standards used by the Department to judge the cost effectiveness of control limits as set forth in Subpart 227-2 Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x) is \$5,500 per

[8] "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, p. 10.
[9] E-mail from Michael Baran (Johnson Matthey) to John Barnes, April 17, 2008.
[10] See Appendix 18A
[11] 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.
[12] Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, page 202.
[13] IBID, page 200.

ton of NO_x removed from the exhaust gas. This value is used in determining whether a "waiver" should be granted to a major stationary source which demonstrates that the cost of such controls is unreasonable. As an analogy, the Subpart 227-2 NO_x standard that would apply to hydraulic fracturing engines if they were considered stationary sources is 2.3 g/bhp-h. Hydraulic fracturing engines equipped with SCRs will have emission rates ranging from 0.26 g/bhp-h (Tier I4) to 0.43 g/bhp-h (Tier 2).

Table 2: Cost Effectiveness of SCR Control on Hydraulic Fracturing Engines

Engine Tier	Annualized Cost	NO_x Removed (tons)	Cost Effectiveness (ton^{-1})
2	$28,000	9.64	$2,907
I4	$22,500	6.03	$3,732
4	$22,000	5.80	$3,816

Summary and Recommendations

The costs for mitigating the modeled NO_2 NAAQS exceedences are considered reasonable. The costs of control presented in Table 2 are less than the cost threshold for the Department's Reasonably Available Control Technology (RACT) for NO_x which is $5,500 per ton. The NO_x emission limits for these engines will range from 0.26 g/bhp-h (Tier 4) to 0.43 g/bhp-h (Tier 2). Therefore, it is concluded that the large (2250 hp) hydraulic fracturing engines can be, cost-effectively, equipped with SCR control systems as recommended in the SGEIS.

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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**

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Appendix 19

Greenhouse Gas
(GHG)
Emissions

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Part A

GHG Tables

Updated July 2011

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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

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[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).

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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.

$$70{,}000\,\frac{miles}{project}\times\frac{gallon\ diesel}{7\ miles}=10{,}000\,\frac{gallons\ diesel\ consumed}{project\ move}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in API's Table 4-1. This factor is provided on a heat basis, so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of 5.75×10^6 Btu/bbl (HHV), given in Table 3-5 of this document. Thus, the fuel heat rate is:

$$10{,}000\,\frac{gallons}{project\ move}\times\frac{bbl}{42\ gallons}\times\frac{5.75\ x\ 10^6\ Btu}{bbl}=1{,}369{,}047{,}619\,\frac{Btu}{project\ move}(HHV)$$

According to API's Table 4-1, the fuel basis CO_2 emission factor for diesel fuel (diesel oil) is 0.0742 tonne $CO_2/10^6$ Btu (HHV basis).

Therefore, CO_2 emissions are calculated as follows, assuming 100% oxidation of fuel carbon to CO_2:

$$1{,}369{,}047{,}619\,\frac{Btu}{project\ move}\times0.0742\,\frac{tonne\ CO2}{10^6}Btu=101.78\,\frac{tonnes\ CO2}{project\ move}$$

To convert tonnes to US short tons:

$$101.78\ tonnes\times2204.62\,\frac{lbs}{tonne}\div2000\,\frac{lbs}{short\ ton}=112.19\ tons\,\frac{CO2}{project\ move}$$

[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

DEC

Appendix 20

PROPOSED
Pre-Frac Checklist and Certification

Updated July 2011

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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. Approval Date & Brief Description of Approved Revision(s) *(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. Approval Date & Brief Description of Justification *(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.

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.

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Appendix 21

Publically Owned Treatment Works (POTWs) With Approved Pretreatment Programs

Revised Draft
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

Publically Owned Treatment Works (POTWs) Procedures for Accepting Wastewater from High-Volume Hydraulic Fracturing

Revised July 2011

Revised Draft
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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

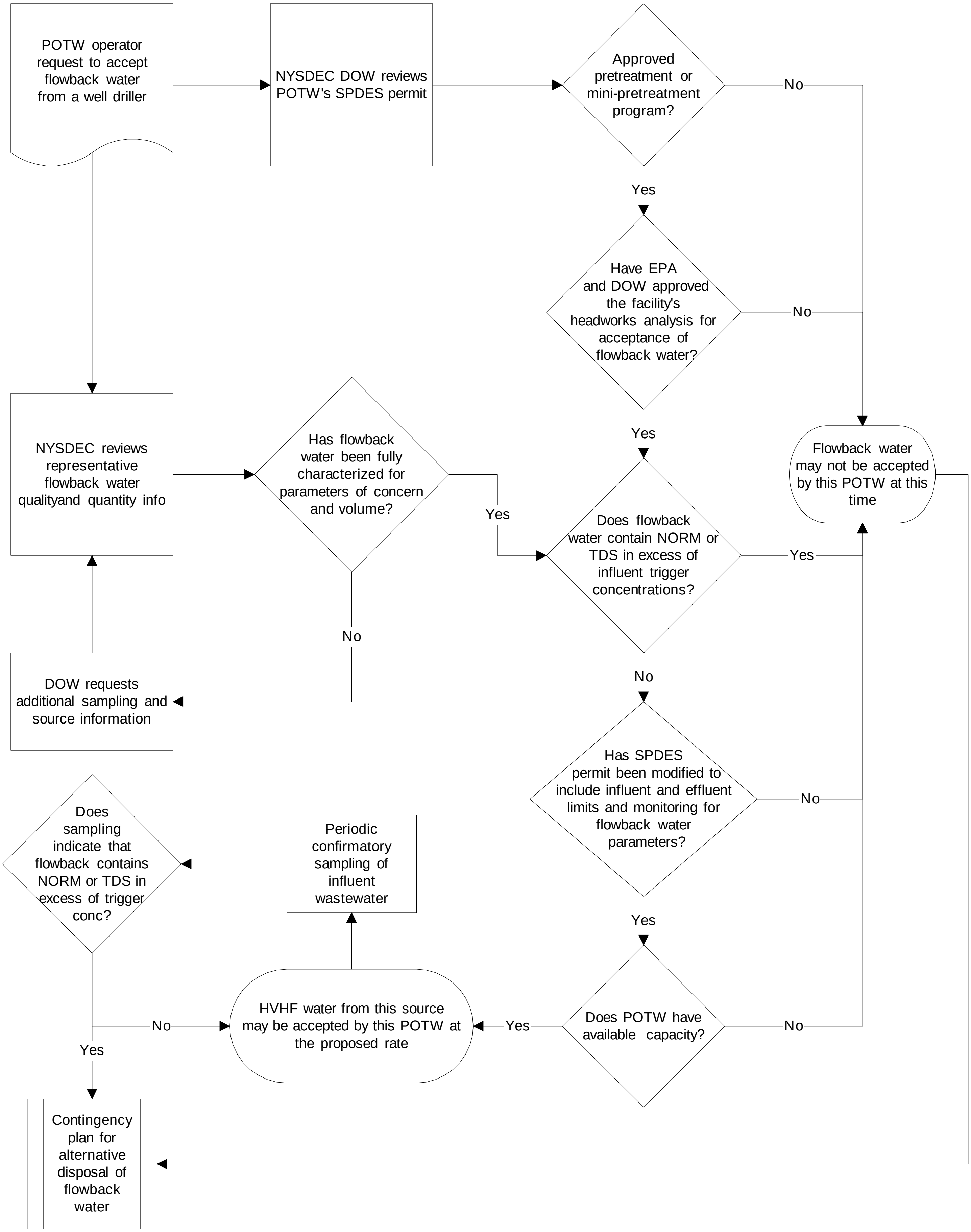
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations 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

Revised Draft
Supplemental Generic Environmental Impact Statement

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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 the 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.

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[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

Revised Draft
Supplemental Generic Environmental Impact Statement

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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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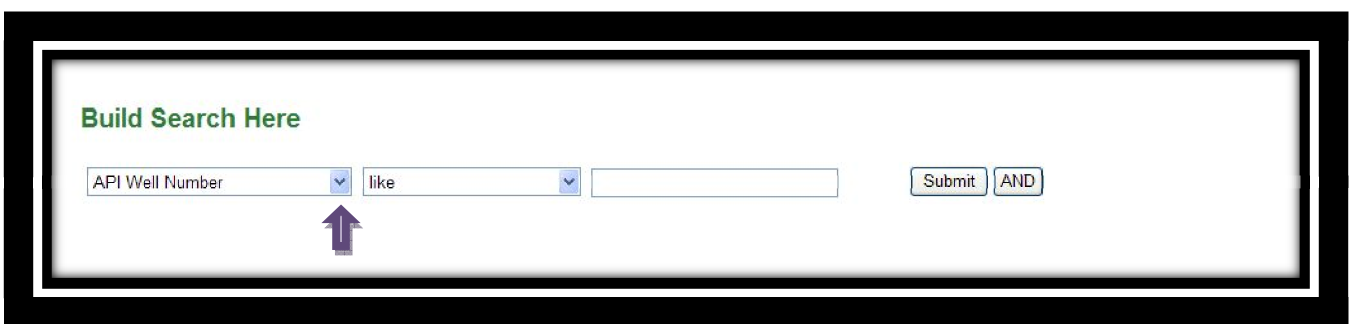
How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

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.

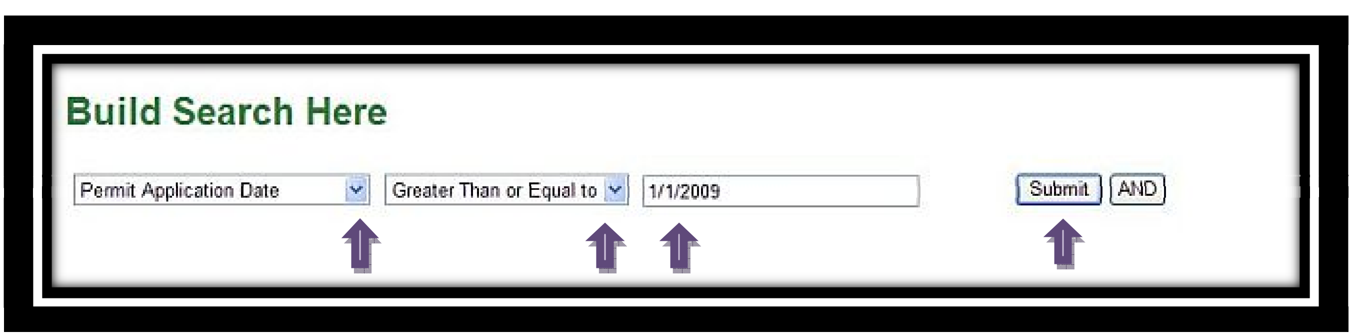
How to Conduct a Simple Search

1. Select Wells Data to begin your search.

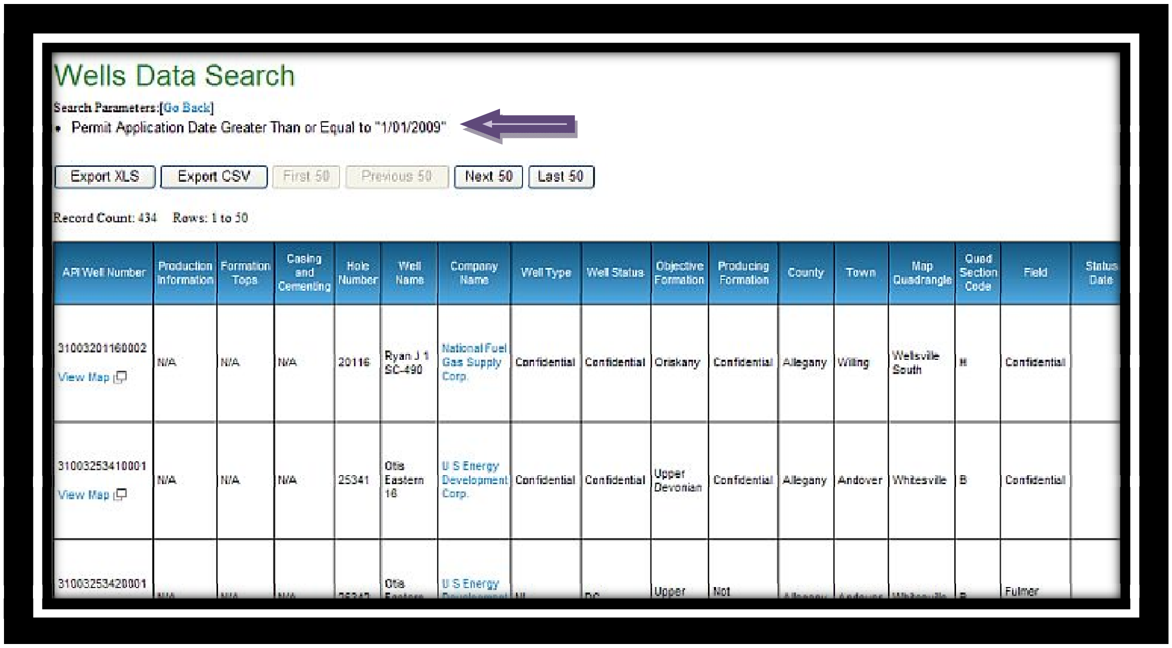
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.



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.



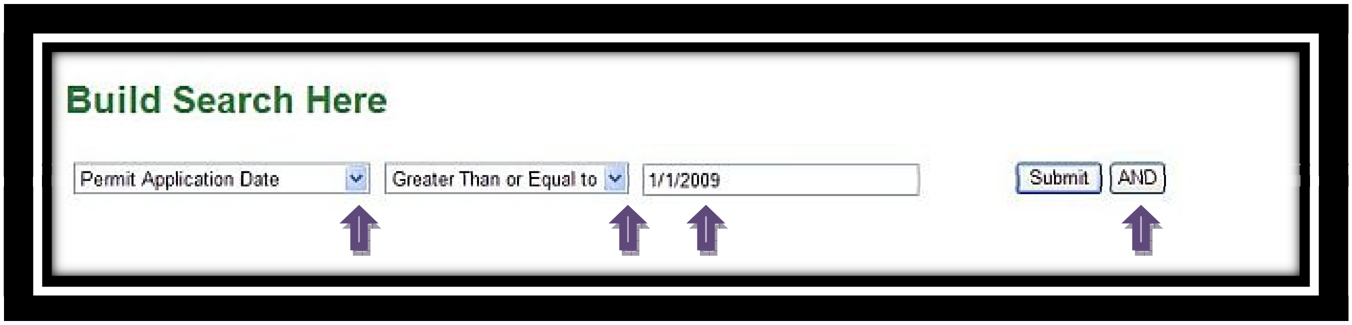
4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) 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.



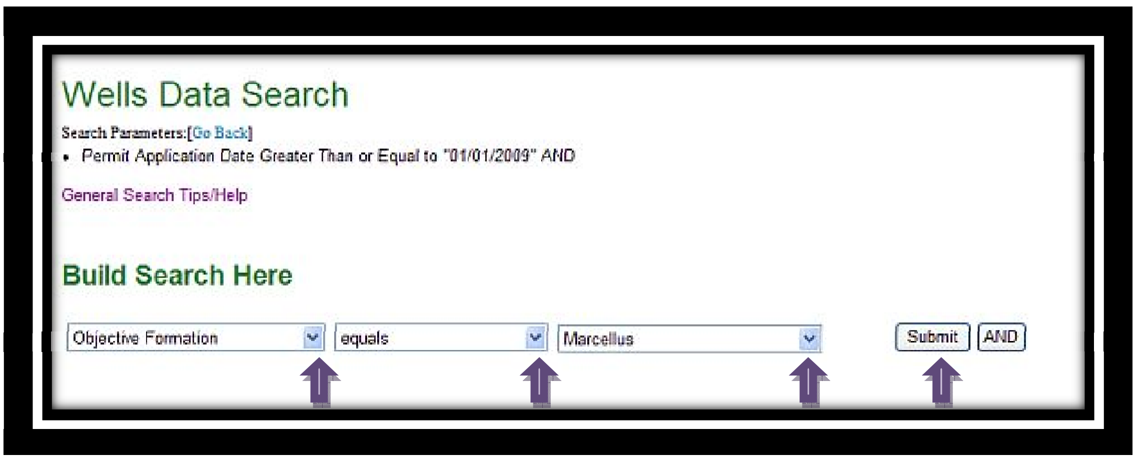
How to Narrow or Expand Your Search Utilizing the AND Button

1. Select Wells Data to begin your search.

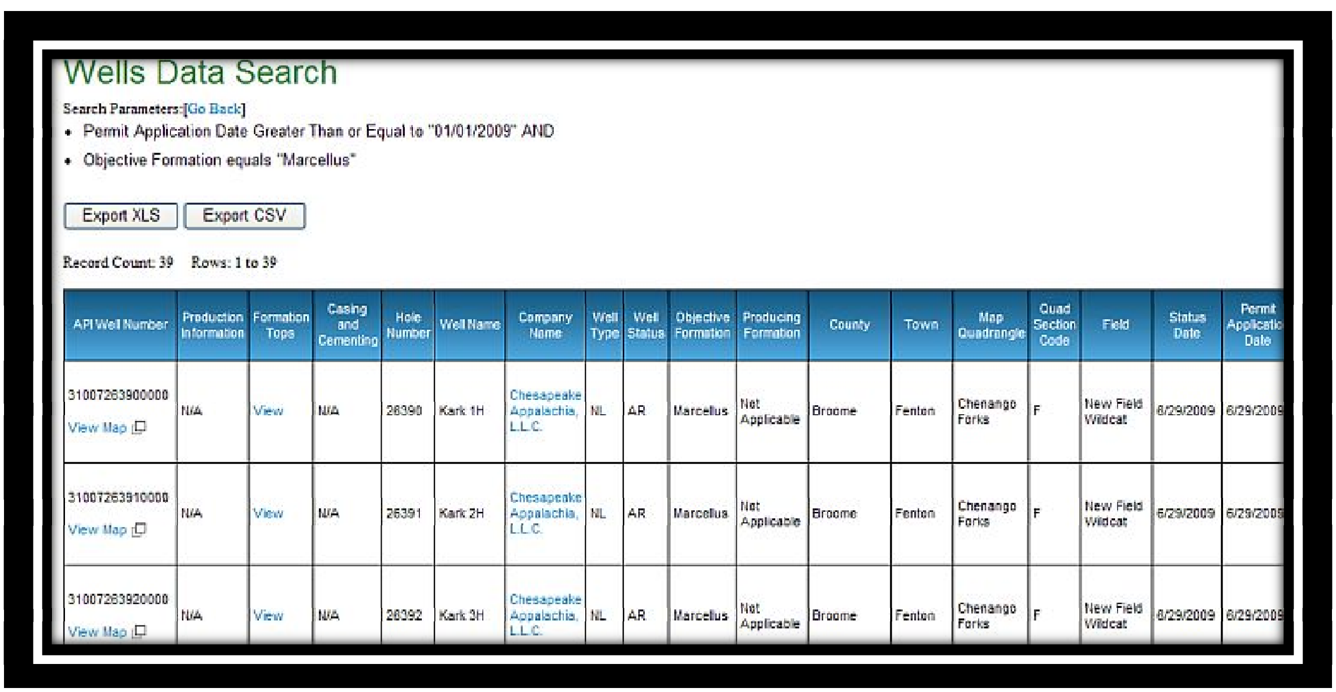
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



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.

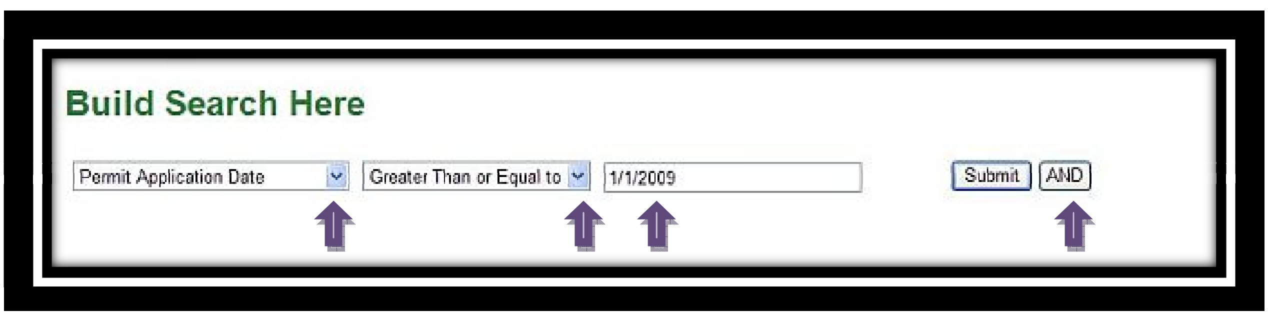


API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date	Permit Applicatio Date
31007263900000 View Map	N/A	View	N/A	26390	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.

New York State

DEC

Appendix 27

NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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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. _____

---

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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