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

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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

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New York State

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Appendix 14

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

Revised Draft
Supplemental Generic Environmental Impact Statement

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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 SEAN D. LOGAN, DIRECTOR

John F. Husted, Chief
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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

STATE OIL AND GAS BOARD OF ALABAMA

OIL AND GAS BOARD
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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.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

vg Carrillo

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

Part B

IOGCC's Statements from Oil & Gas Regulators from 12 Member States

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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

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

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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

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[14] Id. at 36

[15] Letter from Cheryl Newton, U.S. EPA, to Scott Huber, Summit Petroleum Corporation, October 18, 2010, at 4, http://www.epa.gov/region07/air/title5/t5memos/singler5.pdf

[16] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 21, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[17] Id. at 36 – 37.

[18] Letter from Richard Long of EPA Region VIII to Lynn Menlove of Utah Division of Air 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

[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

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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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New York State

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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

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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

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[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

[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.

New York State

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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

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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2007 Annual Mobile Source Emissions

MOVES 2010a Based Inventory Runs

Includes all MOVES Emission Processes Except Evap. Permeation, Evap. Vapor Venting & Evap. Fuel Leaks

		Base Emissions						Emissions resulting from additonal VMT from proposed drilling activity					
FIPS	County	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO	NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
		(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
36001	ALBANY	8423.0	3323.7	64.2	356.3	339.0	51044.0	8447.2	3326.2	64.3	357.6	340.2	51067.1
36003	ALLEGANY	1436.5	495.0	8.5	63.8	60.9	7205.9	1458.5	497.1	8.6	64.8	61.9	7227.5
36007	BROOME	4807.1	1998.9	36.2	209.0	198.5	30424.5	4830.2	2001.2	36.3	210.2	199.6	30447.8
36009	CATTARUAGUS	2446.6	839.0	15.0	107.9	103.0	12115.4	2468.7	841.2	15.0	108.9	104.0	12137.9
36011	CAYUGA	2020.5	774.2	13.6	84.0	80.2	11210.1	2043.2	776.5	13.7	85.2	81.3	11231.9
36013	CHAUTAQUA	4178.1	1410.3	26.5	184.6	176.3	20379.8	4200.5	1412.5	26.6	185.7	177.3	20402.2
36015	CHEMING	2113.2	861.3	15.1	89.3	85.2	12366.7	2137.1	863.8	15.1	90.5	86.4	12390.9
36017	CHENANGO	1066.9	510.5	7.9	43.8	41.5	7513.7	1089.4	512.8	7.9	44.9	42.6	7535.9
36023	CORTLAND	1653.3	543.1	11.1	71.8	68.5	8158.8	1675.5	545.3	11.1	72.9	69.6	8180.9
36025	DELAWARE	1224.2	539.2	9.0	50.1	47.5	8013.5	1246.3	541.3	9.1	51.1	48.6	8034.7
36029	ERIE	19260.0	7997.4	138.2	798.8	760.4	117094.0	19282.6	7999.7	138.3	799.9	761.5	117116.0
36037	GENESEE	3035.1	855.2	20.5	127.1	121.5	13116.7	3057.1	857.4	20.6	128.2	122.6	13138.1
36039	GREENE	1997.6	672.1	14.1	83.1	79.3	10151.8	2020.1	674.4	14.2	84.2	80.4	10174.1
36051	LIVINGSTON	1911.9	683.9	12.3	83.5	79.6	10006.3	1934.2	686.1	12.4	84.6	80.7	10028.8
36053	MADISON	1797.8	729.6	13.1	73.4	69.9	10881.9	1820.3	731.8	13.2	74.6	71.0	10903.7
36065	ONEIDA	4997.0	2222.6	38.1	211.2	200.7	32376.2	5020.6	2225.1	38.1	212.4	201.8	32399.3
36067	ONONDAGA	11468.5	4535.9	82.3	501.2	477.7	66575.9	11492.9	4538.4	82.4	502.4	479.0	66600.0
36069	ONTARIO	3628.0	1241.3	25.5	150.8	144.0	18507.6	3650.8	1243.7	25.6	152.0	145.1	18529.9
36071	ORANGE	7527.5	3123.6	49.7	302.3	286.3	53982.4	7551.6	3126.0	49.8	303.6	287.5	54005.2
36077	OTSEGO	1620.0	640.5	11.4	70.1	66.6	9659.1	1641.8	642.6	11.5	71.1	67.6	9681.4
36095	SCHOHARIE	1505.6	496.2	11.6	62.0	59.0	7964.9	1527.7	498.4	11.7	63.1	60.1	7987.0
36097	SCHUYLER	558.3	215.0	3.8	22.8	21.7	3102.1	580.9	217.4	3.9	23.9	22.9	3122.9
36099	SENECA	1234.1	401.9	8.3	52.1	49.8	5979.4	1256.6	404.2	8.4	53.2	50.8	6002.1
36101	STEUBEN	3969.5	1197.4	24.2	173.8	166.3	17845.0	3991.3	1199.5	24.3	174.9	167.3	17867.0
36105	SULLIVAN	1481.6	752.4	11.8	58.4	55.3	11050.7	1504.9	754.7	11.9	59.6	56.5	11070.8
36107	TIOGA	1398.8	599.9	10.5	57.6	54.9	8538.5	1423.3	602.6	10.6	58.9	56.2	8561.8
36109	TOMPKINS	1727.3	790.5	12.8	72.3	68.8	11227.7	1751.6	793.1	12.9	73.5	70.1	11250.9
36111	ULSTER	4114.3	1895.8	36.0	156.2	148.2	29231.2	4138.3	1898.4	36.1	157.5	149.4	29254.8
36121	WYOMING	999.9	414.6	6.5	42.3	40.4	5827.2	1022.8	416.9	6.6	43.5	41.5	5847.9
36123	YATES	477.8	222.1	3.2	19.3	18.4	3152.6	500.8	224.5	3.3	20.5	19.6	3173.5

Total For Counties in Marcellus Shale Area	104,080	40,983	741	4,379	4,170	614,703	104,767	41,053	743	4,413	4,203	615,372

Estimated additional mobile source emissions resulting from additional VMT associated with proposed gas drilling *

NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
686.7	70.0	2.5	34.4	33.3	668.6
Well pad emissions assuming total emissions split equally across all					
0.28	0.03	0.00	0.01	0.01	0.27

Percentage increase in emissions assuming all wells operating

NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
0.66%	0.17%	0.33%	0.79%	0.80%	0.11%

* Does NOT include Evaporative emissions processes

Marcellus Single Pad MOBILE Model Emissions of PM2.5 for CP-33 Comparison

Vehicle Trip Emissions						
Vehicle Type	**Range of Trucks**	**Max Number of Trucks**	**Feet travelled per site***	**Distance travelled per truck (miles)**	**PM 2.5 EF (lbs/mile)**	**Emissions (tons)**
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0003	2.18799E-06
Drilling Rig	30	30	1700	9.66	0.0003	1.45866E-06
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0003	2.4311E-06
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0003	2.4311E-06
Completion Rig	15	15	1700	4.83	0.0003	7.2933E-07
Completion Fluid and Materials	10-20	20	1700	6.44	0.0003	9.72439E-07
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0003	2.4311E-07
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0003	9.72439E-06
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0003	2.91732E-05
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0003	1.21555E-06
Flow Back Water Removal	200-300	300	1700	96.59	0.0003	1.45866E-05
Total		**1340**		**431.44**		**6.51534E-05**

*(1 - 750 foot trip onto site, 1 - 100 foot trip to station, 1- 100 foot trip back from the station and 1-750 foot trip off the site)

Vehicle Idle Emissions						
Vehicle Type	**Range of Trucks**	**Max Number of Trucks**	**Idle Time per truck (hrs)****	**Hours idling per truck type (hrs)**	**PM 2.5 EF (lbs/hr)**	**Emissions (tons)**
Drill Pad and Road Construction Equipment	10-45	45	2	90.00	0.0013	5.74901E-05
Drilling Rig	30	30	2	60.00	0.0013	3.83267E-05
Drilling Fluid and Materials	25-50	50	2	100.00	0.0013	6.38779E-05
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	2	100.00	0.0013	6.38779E-05
Completion Rig	15	15	2	30.00	0.0013	1.91634E-05
Completion Fluid and Materials	10-20	20	2	40.00	0.0013	2.55511E-05
Completion Equipment – (pipe, wellhead)	5	5	2	10.00	0.0013	6.38779E-06
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	2	400.00	0.0013	0.000255511
Hydraulic Fracture Water	400-600	600	2	1200.00	0.0013	0.000766534
Hydraulic Fracture Sand	20-25	25	2	50.00	0.0013	3.19389E-05
Flow Back Water Removal	200-300	300	2	600.00	0.0013	0.000383267
Total		**1340**		**2680.00**		**0.001711927**

** Assume each truck idles at least 2 hours over the duration of the project

Road Dust Emissions

Vehicle Type	Range of Trucks	Max Number of Trucks	Feet travelled per site*	Distance travelled per truck (miles)	PM 2.5 EF (lbs/mile)	Emissions (tons)
Drill Pad and Road Construction Equipment	10-45	45	1700	14.49	0.0863	0.000625511
Drilling Rig	30	30	1700	9.66	0.0863	0.000417007
Drilling Fluid and Materials	25-50	50	1700	16.10	0.0863	0.000695012
Drilling Equipment (casing, drill pipe, etc.)	25-50	50	1700	16.10	0.0863	0.000695012
Completion Rig	15	15	1700	4.83	0.0863	0.000208504
Completion Fluid and Materials	10-20	20	1700	6.44	0.0863	0.000278005
Completion Equipment – (pipe, wellhead)	5	5	1700	1.61	0.0863	6.95012E-05
Hydraulic Fracture Equipment (pump trucks, tanks)	150-200	200	1700	64.39	0.0863	0.002780047
Hydraulic Fracture Water	400-600	600	1700	193.18	0.0863	0.008340142
Hydraulic Fracture Sand	20-25	25	1700	8.05	0.0863	0.000347506
Flow Back Water Removal	200-300	300	1700	96.59	0.0863	0.004170071
Total		**1340**		**431.44**		**0.018626317**

Total PM 2.5 Emissions	Emissions (tons)	Emissions (lbs)
Vehicle Trip Emissions	6.51534E-05	0.13
Vehicle Idle Emissions	0.001711927	3.42
Road Dust Emissions	1.86E-02	37.25
Total	**0.02**	**40.81**

New York State

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Appendix 19

Greenhouse Gas
(GHG)
Emissions

Updated July 2011

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Supplemental Generic Environmental Impact Statement

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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

---

[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:

$$1{,}369{,}047{,}619 \frac{Btu}{project\ move} \times 0.0742 \frac{tonne\ CO2}{10^6} Btu = 101.78 \frac{tonnes\ CO2}{project\ move}$$

To convert tonnes to US short tons:

$$101.78\ tonnes \times 2204.62 \frac{lbs}{tonne} \div 2000 \frac{lbs}{short\ ton} = 112.19\ tons \frac{CO2}{project\ move}$$

[1] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-39, 4-40.

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New York State

DEC

Appendix 20

PROPOSED
Pre-Frac Checklist and Certification

Updated July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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PRE-FRAC CHECKLIST AND CERTIFICATION

Well Name and Number:
(as shown on the Department-issued well permit)

API Number:

Well Owner:

Planned Frac Commencement Date:

Yes No

☐ ☐ Well drilled, cased and cemented in accordance with well permit, or in accordance with revisions approved by the Regional Mineral Resources Manager on the dates listed below and revised wellbore schematic filed in regional Mineral Resources office.

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.

New York State

DEC

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
Supplemental Generic Environmental Impact Statement

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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

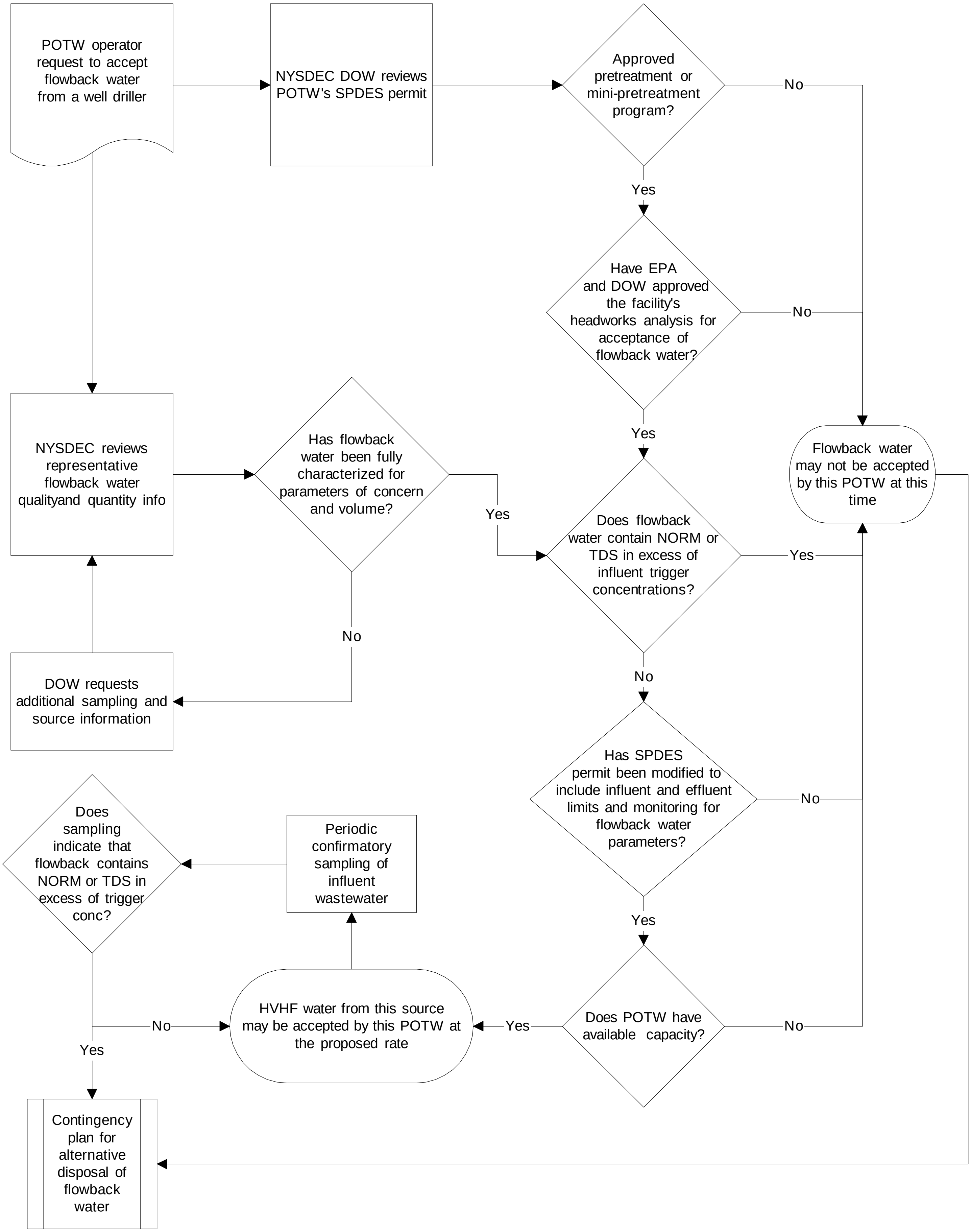
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations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

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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.

[1] New Mexico Environment Department, *Oil and Gas Greenhouse Gas Emissions Reductions*. December 2007, pp. 19-20.

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Appendix 25

Reduced Emissions Completion (REC) Executive Summary

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Reduced Emissions Completions – Executive Summary[1]

High prices and high demand for natural gas, have seen the natural gas production industry move into development of the more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involves hydraulic fracturing of the reservoir to increase well productivity. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and methane emissions to the atmosphere.

Conventional completion of wells (a process that cleans the well bore of stimulation fluids and solids so that the gas has a free path from the reservoir) results in gas being either vented or flared. Vented gas results in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions to the atmosphere while flared gas results in carbon dioxide emissions.

Reduced emissions completion (REC) – also known as reduced flaring completion – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids so that the gas is suitable for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during the well flowback phase and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of eight different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2005 emissions reductions from RECs have increased from 200 MMcf to over 7,000 MMcf. This represents additional revenue from natural gas sales of over $65 million in 2005 (assuming $7/Mcf gas prices).

Method for Reducing Gas Loss	**Volume of Natural Gas Savings (Mcf/yr)[1]**	**Value of Natural Gas Savings ($/yr)[2]**	**Additional Savings ($/yr)[3]**	**Set-up Costs ($/yr)**	**Equipment Rental and Labor Costs ($)**	**Other Costs ($/yr)[4]**	**Payback (Months)[5]**
Reduced Emissions Completion	270,000	1,890,000	197,500	15,000	212,500	129,500	3

1. Based on an annual REC program of 25 completions per year
2. Assuming $7/Mcf gas
3. Savings from recovering condensate and gas compressed to lift fluids
4. Cost of gas used to fuel compressor and lift fluids
5. Time required to recover the entire annual cost of the program

[1]Adapted from ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, *Task 2 – Technical Analysis of Potential Impacts to Air*, Agreement No. 9679, August 2009. Appendix 2.1.

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Appendix 26

Instructions for Using The On-Line Searchable Database to Locate Drilling Applications

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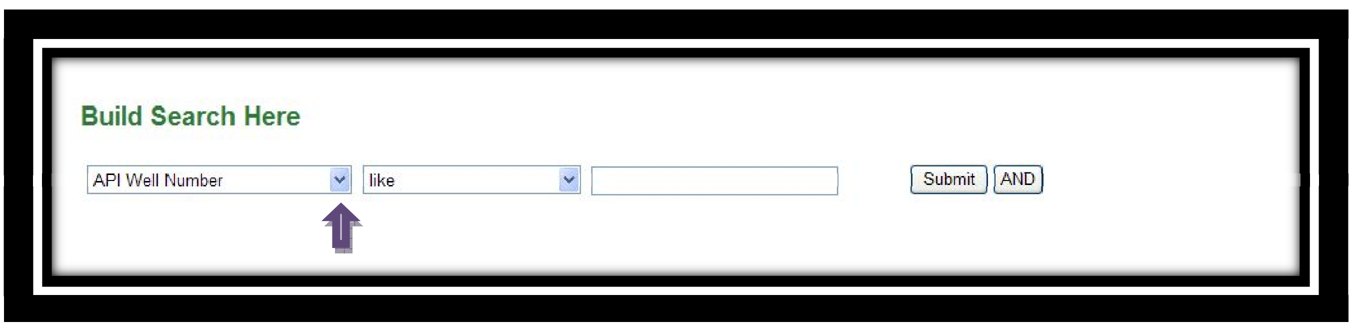
How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

The online searchable database can be found at http://www.dec.ny.gov/cfmx/extapps/GasOil/. It is a very user friendly program and can be used to conduct both simple and complex searches.

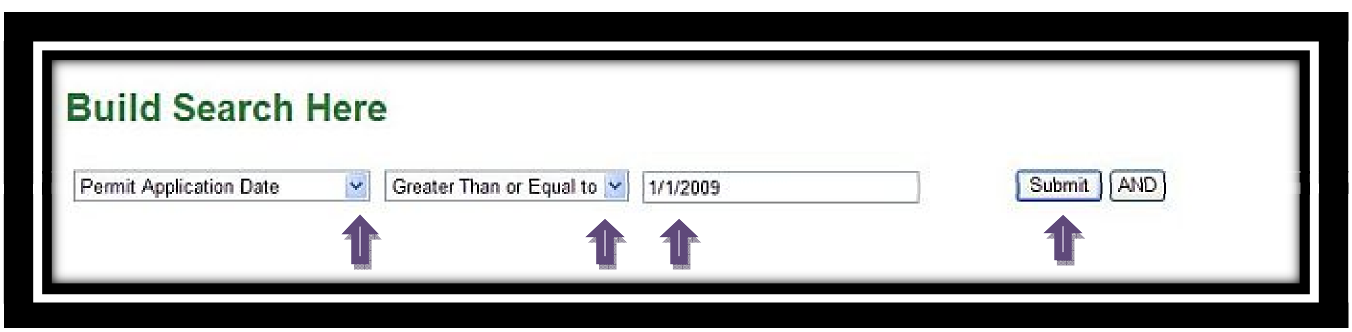
How to Conduct a Simple Search

1. Select Wells Data to begin your search.

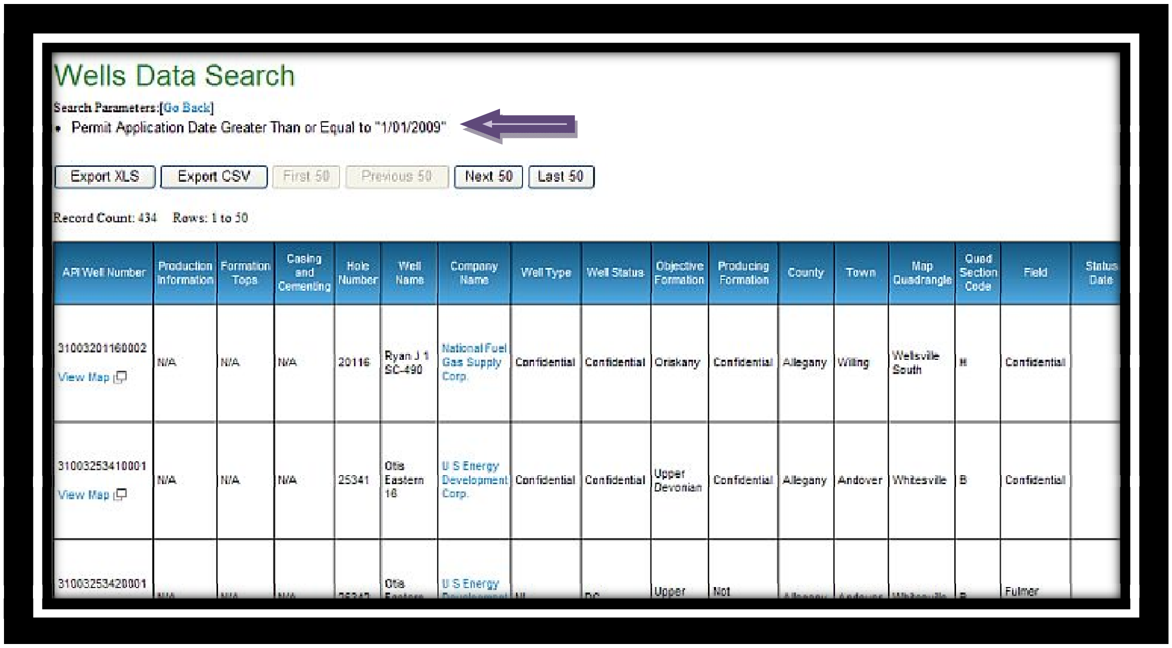
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.



3. To find a new permit application, enter Permit Application Date is Greater Than or Equal to, and the date that you would like to search from. Enter Permit Application Data is Greater Than or Equal to 1/1/year to find all permit applications filed during a specific year. Click the Submit button.



4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv) by clicking the appropriate Export button at the bottom the results screen. Clicking a hyperlink in the Company Name column will provide contact information for the company.



How to Narrow or Expand Your Search Utilizing the AND Button

1. Select Wells Data to begin your search.