NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Appendix 16

Applicability of NO_x RACT Requirements for Natural Gas Production Facilities

Final

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 227-2, Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_X), applies to boilers (furnaces) and internal combustion engines at major sources.

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

New York State has two different major source thresholds for NO_X RACT and permitting. Downstate (in New York City and Nassau, Suffolk, Westchester, Rockland, and Lower Orange Counties) the major source permitting and NO_X RACT requirements apply to facilities with a PTE of 25 tons/yr or more of NO_X. For the rest of the state (where the majority of natural gas production facilities are anticipated to be located), the threshold is a PTE of 100 tons/yr or more of NO_X.

If the stationary engines at a natural gas production facility exceed the applicability levels or if the PTE at the facility would classify it as a Major NO_X source, the following compliance options are available:

1. Develop a NO_X RACT compliance plan and apply for a Title V permit.

2. Limit the facility's emissions to remain under the NO_X RACT applicability levels by applying for one of two New York State Air Emissions permits, depending on how low emissions can be limited.

The permitting options for facilities that wish to limit, or "cap", their emissions by establishing appropriate permit conditions are described below.

New York State's air regulation 6 NYCRR Part 201, Permits and Registrations, includes a provision that allows a facility to register if its actual emissions are less than 50% of the applicability thresholds (less than 12.5 tons/yr downstate and less than 50 tons/yr upstate). This permit option is known as "cap by rule" registration.

Part 201 also includes a provision that allows a facility to limit its emissions by obtaining a State Facility Permit, if its actual emissions are above the 50% level but below the applicability level (between 12.5 and 25 tons/yr downstate and between 50 and 100 tons/yr upstate).

If the facility NO_X emissions cannot be capped below the applicability levels, then the facility should immediately develop a NO_X RACT compliance plan. This plan should contain the necessary steps (purchase of equipment and controls, installation of equipment, source testing, submittal of permit application, etc.) and projected completion dates required to bring the facility into compliance. This plan is to be submitted to the appropriate Department Regional Office as soon as possible. In this case the facility would also be subject to Title V, and a Title V air permit application must be prepared and submitted.

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Appendix 17

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

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

EPA published a final rule on August 20, 2010 revising 40 CFR Part 63, Subpart ZZZZ, in order to address hazardous air pollutant (HAP) emissions from existing stationary reciprocating internal combustion engines (RICE) located at area sources. A major source of HAP emissions is a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAPs at a rate of 25 tons or more per year. An area source of HAP emissions is a source that is not a major source.

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

The applicable emission standards (at 15% oxygen) or management practices for existing RICE located at area sources are provided in the table below.

In addition to emission standards and management practices, certain stationary CI RICE located at existing area sources are subject to fuel requirements. Stationary non-emergency diesel-fueled CI engines greater than 300 HP with a displacement of less than 30 liters per cylinder located at existing area sources must only use diesel fuel meeting the requirements of 40 CFR 80.510(b), which requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

Subcategory	Emission standards at 15 percent O_2, as applicable, or management practice	
	Except during periods of startup	**During periods of startup**
Non-Emergency 4SLB* >500HP	47 ppmvd CO or 93% CO reduction	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
Non-Emergency 4SLB ≤500HP	Change oil and filter every 1440 hours; inspect spark plugs every 1440 hours; and inspect all hoses and belts every 1440 hours and re-place as necessary.	Same as above
Non-Emergency 4SRB >500HP**	2.7 ppmvd formaldehyde or 76% formaldehyde reduction.	Same as above
Non-Emergency CI >500HP	23 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI* 300-500HP**	49 ppmvd CO or 70% CO reduction	Same as above
Non-Emergency CI ≤300HP	Change oil and filter every 1000 hours; inspect air cleaner every 1000 hours; and inspect all hoses and belts every 500 hours and re-place as necessary.	Same as above

*4SLB - four stroke-cycle lean burn
**4SRB - four stroke-cycle rich burn
***CI - compression ignition

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Appendix 18

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

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

Summary

The Department must determine the applicability of air permitting regulations and requirements to natural gas drilling activities in the Marcellus Shale formation. Specifically, the Department must determine applicable regulations and permit requirements for:

- sources subject to stationary source permitting under 6 NYCRR Part 201.
  major stationary source **-** one that emits or has the potential to emit any of the following:
  - 100 tons per year (Tpy) or more of any regulated air pollutant (NO_X, SO_2, CO, PM2.5, PM_{10}); 50 Tpy of VOC.
  - 10 Tpy or more of any individual Hazardous Air Pollutant (HAP); or
  - 25 Tpy or more of any combination of HAPs.

- sources subject to New Source Performance Standards (**NSPS**)

- sources subject to National Emission Standards for Hazardous Air Pollutants (**NESHAP**), and

- 6 NYCRR Part 231 for major new or major modifications to existing sources subject to preconstruction review requirements under Prevention of Significant Deterioration (**PSD**) and/or Non-Attainment New Source Review (**NSR**)

In addition to threshold criteria detailed in regulation and guidance, the Department must evaluate a variety of technical and factual information to assess applicability of these rules to specific sources through the permit application process. These evaluations, as they pertain to natural gas drilling activities in the Marcellus Shale formation, are discussed herein, including 1) whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source for purposes of NSR and Title V programs; and 2) how to assess NESHAP applicability given the unique regulatory definition of “facility” for the oil and gas industry.

Major Stationary Source Determinations for Criteria Pollutants

PSD, NSR and Title V operating permit program (Title V) regulations apply to certain sources with the potential to emit pollutants in excess of the major source thresholds. To assess applicability, the Department must evaluate whether emissions from two or more pollutant-emitting activities should be aggregated into a single major stationary source. The evaluation begins with the federal definition of “stationary source” at 40 CFR 52.21(b)(5) and a similar definition for major source under 6 NYCRR 201-2.1(b)(21). The federal definition reads “any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant.” “Building, structure, facility, or installation” is further defined in 40 CFR 52.21(b)(6):

Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

To identify pollutant-emitting activity that belongs to the same building, structure, facility, or installation, permitting authorities rely on the following three criteria: 1) whether the activities belong to the same industrial grouping; 2) whether the activities are located on one or more contiguous or adjacent properties; and 3) whether the activities are under the control of the same person (or person under common control).[1] These criteria are applied case-by-case to make the major stationary source determination.

Since the original 1992 GEIS, DEC reviewed numerous source determinations from EPA permitting actions, guidance provided by EPA to inform permitting actions by other permitting authorities, and source determination protocol developed by other states. These documents have been informative. However, EPA has clearly stated that "no single determination can serve as an adequate justification for how to treat any other source determination for pollutant-emitting activities with different fact-specific circumstances."[2] "Therefore, while the prior agency statements and determinations related to oil and gas activities and other similar sources may be instructive, they are not determinative in resolving the source determination issue…, particularly where a state with independent permitting authority is making the determination and the prior agency statements had… substantially different fact-specific circumstances."[3] As such, DEC will formulate case-specific source determinations based on the foregoing, federal and state regulation, evolving case law, industry data and the specific facts of each air permit application. These determinations will be made during the review of permit applications for compressor stations which are associated with Marcellus Shale activities.

The three source determination criteria are discussed in more detail below.

1) **Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group"?** In formulating the definition of "source," EPA uses a Standard Industrial Classification (SIC) code for distinguishing between sets of activities on the basis of their functional interrelationships.[4] Each source is to be classified according to its primary

[1] Memorandum from Gina McCarthy, EPA Assistant Administrator, to Regional Administrators, Sept. 22, 2009, available at http://www.epa.gov/region7/air/nsr/nsrmemos/oilgaswithdrawal.pdf

[2] Id.

[3] In The Matter Of Anadarko Petroleum Corporation, Frederick Compressor Station, Order Responding To Petitioners' Request That The Administrator Object To Issuance Of A State Operating Permit, February 2, 2011, Petition Number: VIII-2010-4.

[4] 45 FR 52695, at 31.

activity, which is determined by its principal product or group of products produced or distributed, or services rendered.[5]

The Standard Industrial Classification Manual lists activities associated with oil and gas extraction in Major Group 13 and activities associated with natural gas transmission in Major Group 49. Establishments primarily engaged in operating oil and gas field properties, including wells, are grouped into Major Group 13. The Standard Industrial Classification Manual does not expressly list all equipment, such as midstream compressor stations, in Major Group 13, nor Major Group 49. Therefore, the Department may look to other information, such as federal and state regulations, industry data, and gas gathering agreements, to help make the source determination. For instance, under NESHAP, EPA regulates compressor stations that transport natural gas to a natural gas processing plant[6] in accordance with natural gas production facilities, Major Group 13.[7] In the absence of a natural gas processing plant, EPA regulates a compressor station in accordance with natural gas production facilities where the compressor station is prior to the point of custody transfer.[8] If the compressor station is after the point of custody transfer, EPA regulates the compressor station in accordance with natural gas transmission and storage facilities, Major Group 49. In relevant part, custody transfer means the transfer of natural gas to pipelines *after processing or treatment*.[9]

Where the pollutant-emitting activities do not belong to the same industrial grouping or "Major Group," the Department will ascertain whether one activity serves exclusively as a support facility for the other. In the Preamble to its 1980 PSD regulations, EPA "clarifies that "support facilities" that "convey, store, or otherwise assist in the production of the principal product" should be considered under one source classification, even when the support facility has a different two-digit SIC code.[10]

2**)** **Are the pollutant-emitting activities contiguous or adjacent?** EPA has routinely relied on the plain meaning of the word "contiguous," that is - being in actual contact; touching along a boundary or at a point. However, "the more difficult assessment is determining whether … a non-contiguous [pollutant-emitting activity] might be considered "adjacent."[11] First, EPA has not established a specific distance between activities in assessing whether such activities are adjacent.[12] Second, "the concept of "interdependency," which many individual EPA determinations consider, is not discussed in the 1980 Preamble or mentioned in the federal PSD or Title V regulations defining "source."[13] "[I]nterdependency is a factor that has evolved over time in various case-by-case determinations. While interdependency is a

[5] 45 FR 52695, at 32.
[6] 40 CFR §63.761, *Natural gas processing plant.*
[7] 40 CFR §63.761, *Facility.*
[8] 40 CFR §63.760(a)(3)
[9] 40 CFR §63.761, *Custody transfer.*
[10] 45 Fed. Reg. 52676 (August 9, 1980)
[11] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 15, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[12] Id.
[13] Id. at 14

consideration, it is not an express element of the actual three-part test set forth in regulation, and in the context of oil and gas infrastructure, it may have reduced relevance to an agency determination"[14] Nevertheless, to be thorough, DEC staff will consider the nature of the relationship between the facilities and the degree of interdependence between them.[15] However, interdependence alone may not be dispositive of whether the non-contiguous emissions points should be aggregated in this context.

A "high level of connectedness and interdependence between two activities" is needed to deem them adjacent, and "interdependence requires that the two activities rely on each other – not just that one activity relies on the other activity.[16] Furthermore, "a determination of interdependence requires that the two activities rely upon each other *exclusively*; i.e., one activity cannot operate or occur without the other. The case-by-case determinations indicate that if activities operate independently and one activity does not act solely as a support operation for the other, the activities should not be deemed contiguous or adjacent."[17] In guidance provided by EPA to the Utah Division of Air Quality,[18] EPA recommended using the following indicators as determinative of adjacency for two Utility Trailer Manufacturing Company facilities: 1) whether the location of the new facility was chosen because of its proximity to the existing facility; 2) whether materials would routinely be transferred back and forth between the two facilities; 3) whether managers and other workers would be shared between the two facilities; and 4) whether the production process itself would be split between the two facilities.[19] While DEC will use these and other questions to inform its source determination, some questions may have reduced relevance in the oil and gas industry. For instance, the location of oil and gas activity, proximate or otherwise, may "be controlled by land agreements, access issues, geologic formations, terrain, and, in other situations, by federal or state land management agencies, such as the Bureau of Land Management for oil and gas production on federal lands,"[20] and thus not necessarily indicative of interdependence.

3) **Are the activities under common control?** To assess common control, EPA has historically relied on the Securities and Exchange Commission's definition of control as follows: The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association), whether through the ownership of voting shares, by contract or otherwise. The following questions have been used previously and in more recent actions by EPA to determine

[14] Id. at 36

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

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

[17] Id. at 36 – 37.

[18] Letter from Richard Long of EPA Region VIII to Lynn Menlove of Utah Division of Air Quality, dated May 21, 1998. http://www.epa.gov/region07/air/title5/t5memos/util-trl.pdf

[19] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 20, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

[20] Id. at 40

"common control":[21] 1) Whether control has been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation; 2) Whether control has been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity; 3) Whether there is a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract; 4) Whether there is a support or dependency relationship between the two entities such that one would not exist "but for" the other?

Thus, the Department will use answers to the following questions to help guide the case-specific source determinations for natural gas drilling activities in the Marcellus Shale formation that may be subject to NSR and Title V for criteria pollutants.

1. Do the pollutant-emitting activities belong to the same industrial grouping or "Major Group" as described in the Standard Industrial Classification Manual?
    a. What is the primary activity engaged in by the facility?
    b. If the pollutant-emitting activities do not belong to the same industrial grouping or Major Group, does one activity serve exclusively as a support facility for the other?
2. Are the pollutant-emitting activities contiguous or adjacent?
    a. Are the pollutant-emitting activities contiguous? Do they share a boundary or touch each other physically?
    b. If the pollutant-emitting facilities are non-contiguous, are they proximate or interdependent?
    c. Was the location of the new facility chosen because of its proximity to the existing facility?
    d. Will materials routinely be transferred back and forth between the two facilities?
    e. Will managers and other workers be shared between the two facilities?
    f. Will the production process be split between the two facilities?
3. Are the activities under common control?
    a. Has control been established through ownership of two entities by the same parent corporation or a subsidiary of the parent corporation?
    b. Has control been established by a contractual arrangement giving one entity decision making authority over the operations of the second entity?
    c. Is there a contract for service relationship between the two entities in which one sells all of its product to the other under a single purchase or contract?

[21] Letter from Kathleen Henry of EPA Region III to John Slade of Pennsylvania DEP, dated 1/15/99. Also, Letter from Richard Long of EPA Region VIII to Margie Perkins, Air Pollution Control Division, Colorado Department of Public Health Environment, dated October 1, 1999, http://www.epa.gov/region07/air/nsr/nsrmemos/frontran.pdf

d. Is there an exclusive support or dependency relationship between the two entities such that one would not exist "but for" the other?

NESHAPS Applicability for Hazardous Air Pollutants

"[I]n the hazardous air pollutant (HAP) arena, EPA has expressly determined, consistent with Congress' statutory mandate in the [Clean Air Act] CAA, 42 U.S.C. § 7412(n)(4)(A), oil and gas production field facilities are typically not industrial facilities that should be aggregated."[22] The CAA, 42 U.S.C. § 7412, defines "major source" as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants; and "area source" as any stationary source of hazardous air pollutants that is not a major source. Notwithstanding this definition, Section 7412(n)(4)(A) exempts oil and gas wells and pipeline facilities from the requirement to aggregate with contiguous sources under common control when deciding if the source is a major source for NESHAPS applicability.

In the context of hazardous air pollutants, EPA declared that "[s]uch facilities generally are not in close proximity to or co-located with one another (contiguous) and located within an area boundary, the entirety of which (other than roads, railroads, etc.), is under the physical control of the same owner."[23,24] In light of this, EPA developed a unique definition of facility for the oil and gas industry NESHAP regulations (40 CFR 63 Subparts HH and HHH). For HAP major source determinations, the EPA-promulgated definition of "facility" states that "pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts . . . or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility."[25,26] EPA defines a "surface site" at 40 CFR 63.761 of Subpart HH as " Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed".

Accordingly, to determine applicability of the NESHAPs rules governing Oil and Gas Production and Natural Gas Transmission industry sectors, the regulatory definition of facility authorized by CAA, 42 U.S.C. § 7412(n)(4)(A) and found at 40 CFR 63 Subparts HH and HHH, must be used. The Department will follow this definition in determining the regulatory applicability of NESHAPS requirements for HAPS. This opens up the possibility that a "facility" definition for a certain permit application may result in a determination of "major source" for purposes of NSR or Title V permitting, but which will consist of several area source surface sites for the purposes of NESHAP applicability. Guided by EPA's three source determination criteria and the underlying recommendation to use case specific facts, the

[22] Id. at 23
[23] 63 Fed. Reg. 6288, 6303 (Feb. 6, 1998)
[24] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf
[25] 64 Fed. Reg. 32610, 32630 (June 17, 1999)
[26] Response of Colorado Department of Public Health and Environment, Air Pollution Control Division, to Order Granting Petition for Objection to Permit, July 14, 2010, at 23, http://www.cdphe.state.co.us/ap/down/K-MOrderResponseDocumentJuly142010.pdf

Department will consider all pertinent information on a case-by-case basis in arriving at its conclusions during source permitting review.

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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 Operations

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Evaluation of Particulate Matter and Nitrogen Oxides Emissions Factors and Potential Aftertreatment Controls for Nonroad Engines for Marcellus Shale Drilling and Hydraulic Fracturing Operations

Nonroad Emissions Standards

Tables 1 and 2 describe the EPA emissions standards for nonroad diesel engines relevant to natural gas well drilling and hydraulic fracturing. These standards are contained in 40 CFR Parts 89 and 1039. These standards may be considered worst case emission levels. Table 1 covers engines rated from 600-750 horsepower. Table 2 covers engines rated at more than 750 horsepower that are not installed in a generator set. Engines are held to these standards for a useful life of the lesser of 8000 hours or 10 years. Actual operating lifetimes are likely much longer.

Table 1. Nonroad Engine Standards for Engines Rated Between 600 and 750 Horsepower

Standard	Initial Year	PM (g/bhp*hr)	NO_X (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	1996	0.4	6.9	1.0	
Tier 2	2002	0.15	4.32	0.48	4.8 g/bhp*hr NO_X + HC standard
Tier 3	2006	0.15	2.7	0.3	3.0 g/bhp*hr NO_X + HC standard
Tier 4 interim	2011	0.01	1.35	0.14	NO_X standard half-way between Tier 3 and Tier 4
Tier 4	2014	0.01	0.3	0.14	

Tier 2 and Tier 3 NO_X and hydrocarbon standards are an additive NO_X plus hydrocarbon (HC) standard. For Tier 2 the limit is 4.8 g/bhp*hr. For Tier 3 the limit is reduced to 3.0 g/bhp*hr. In order to use the standards as conservative emissions limits, it is necessary to apportion the emission limit between the two pollutants. The Tables apportion 90% of the emissions to NO_X and the remaining 10% to hydrocarbons. EPA and European Union (EU) emissions tiers that have separate NO_X and hydrocarbon standards, not requiring exhaust aftertreatment, generally have the NO_X standard equaling 86-88% of the sum of the two standards. It should be noted that data supplied on behalf of industry (1) assumed that 100% of these emissions are NO_X, which is deemed conservative.

There is no official "Tier 4 interim" standard for engines in the Table 1 horsepower class. Beginning in 2011, 50% of the engines in the class are supposed to meet the Tier 4 NO_X standards. This would increase to 100% in 2014. When faced with the exact same phase-in schedule from 2007-2010 for highway diesel engines, manufacturers universally chose to initially certify all engines to a Family Emissions Level half way between the old standard and the new standard, and postpone the NO_X aftertreatment requirements for three years. Thus, the NO_X emissions level of 1.35 g/bhp*hr in the Table is the average of the Tier 3 and Tier 4 standards.

Table 2. Nonroad Engine Standards for Engines Rated Above 750 Horsepower (Updated 2012)

Standard	Initial Year	PM (g/bhp*hr)	NO_X (g/bhp/hr)	HC (g/bhp*hr)	Notes
Tier 1	2000	0.4	6.9	1.0	
Tier 2	2006	0.15	4.32	0.48	4.8 g/bhp*hr NO_X + HC standard
Tier 4 interim	2011	0.075	2.6	0.3	
Tier 4 final	2015	0.03	2.6	0.14	
Tier 4 final	2015	0.02	0.5	0.14	Generator sets only

Tier 1 and Tier 2 standards for engines rated above 750 horsepower are the same as the corresponding standards for engines rated between 600 and 750 horsepower. Again, the Tier 2 NO_X plus hydrocarbon standard is apportioned 90% NO_X and 10% hydrocarbon. There are no Tier 3 standards for these engines. The Tier 4 interim standards are promulgated standards. Also, the Tier 4 standards for engines rated above 750 horsepower not installed in generator sets may not force the use of NO_X aftertreatment, although at least one manufacturer reportedly intends to use SCR on these engines by 2015 (2).

Final Tier 4 standards for generator sets rated above 750 hp are significantly more stringent than the corresponding standards for other engines. Some drilling rigs are designed with electric motors to drive various pieces of equipment rather than mechanical or hydraulic drives. Electric drive pumps for hydraulic fracturing may also be possible. The use of electric drive equipment would allow the use of lower emission diesel engines in the future, as well as the possibility of the use of grid electricity where sufficient electrical power is available.

Retrofit of Exhaust Aftertreatment

Prior to Tier 4, none of the new engine standards were stringent enough to require exhaust aftertreatment. Current highway engine standards require aftertreatment to meet both the PM and NO_X standards. Furthermore, there is now substantial experience with retrofitting exhaust aftertreatment to highway engines and stationary engines. Particulate matter control technologies include: Diesel Oxidation Catalysts (DOC) which oxidize hydrocarbons and carbon based particulate matter, and particulate filters or "traps" where particulate matter is collected and oxidized. Where exhaust conditions are suitable Continuously Regenerating Diesel Particulate Filters (CRDPF) are common. In other cases, particularly when exhaust temperatures are too low, active traps may be used. Active traps use an external energy supply (usually electricity or a secondary fuel burner) to oxidize particulate matter rather than relying solely on exhaust heat. Active trap retrofits may require more complex control systems.

NO_X control technologies include: Selective Catalytic Reduction (SCR) which uses ammonia (usually supplied as urea), Lean NO_X Catalysts, or Lean NO_X Traps (also referred to as "NO_X absorbers") to reduce NO_X emissions. Although in the past EPA had identified the Lean NO_X Traps as a promising technology, it has not been applied to the size class of the drilling and hydraulic fracturing engines. In addition, the lean NO_X Catalyst system's NO_X reduction would be insufficient to meet the ultimate engine standards. Thus, for NO_X control, the SCR system is recommended.

Table 3 lists the aftertreatment effectiveness claimed by one manufacturer, Johnson Matthey,[1] as an example for retrofit installations on stationary engines (3).

Table 3. Exhaust Aftertreatment Retrofit Effectiveness

Technology	Abbreviation	PM Emissions Reduction (%)	NO_X Emissions Reduction (%)	HC Emissions Reduction (%)
Diesel Oxidation Catalyst	DOC	30%	0	90%
Particulate Trap	CRDPF	85%	0	90%
Particulate Trap and SCR	SCR-DPF (SCRT)	85%	90%	90%

Johnson Matthey has EPA certification of its SCR-DPF system (referred to as SCRT) as a verified retrofit for some classes of highway diesel engines. That verification is for a 70% NO_X emissions reduction (4). The development of Johnson Matthey's retrofit system is described by Conway and coworkers (5). This certification does not negate the 90% reduction expected for these nonroad engines due to factors discussed below.

The SCR and CRDPF technologies are the dominant technologies used to meet the current highway emissions standards, and are expected to dominate the exhaust aftertreatment market for many large nonroad diesel engine classes. There are other NO_X control technologies; however their applicability appears to be limited to smaller engines, such as those in light duty vehicles.

Feasibility of Exhaust Aftertreatment

As discussed above, SCR and CRDPF technologies are widely used to control NO_X and PM emissions from diesel cycle internal combustion engines, including engines both larger and smaller than well drilling and hydraulic fracturing engines. These technologies are used both on new engines and as retrofits to existing engines.

No exhaust aftertreatment retrofits for these engines and duty cycles have been verified by EPA or the California Air Resources Board (CARB). Both verification programs are voluntary. The primary purpose of the EPA verification program is to verify eligibility for federal diesel emission reduction retrofit grants. The primary purpose of the CARB program is to verify emissions reductions for use by engine owners in complying with California's Airborne Toxic Control Measures for diesel particulate matter. To the Department's knowledge no exhaust retrofits for the gas well drilling rig and hydraulic fracturing engines expected to be used in developing the Marcellus Shale formation in New York have been submitted to either verification program.

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

Lack of verification does not necessarily preclude commercial application of a retrofit. However, verification, which requires significant work by the applicant, does provide benefits to all parties. Verification provides assurances regarding the level of emissions control, and assurance that the control equipment will continue to be effective over a period of time. The verification programs also impose warranty requirements.

The intended duty cycle of the engine is an important factor in the design of emissions control systems. Particularly critical for CRDPF installations is the exhaust temperature. Exhaust temperature must be high enough, frequently enough, to oxidize accumulated particulate matter. Failure to regenerate the particulate trap can lead to engine damage. The exhaust temperatures reported on behalf of industry (800-900 °F) (1) are high enough to support aftertreatment retrofits which require minimum temperatures of roughly 250 °C (<500 °F) (4) (5). The fraction of time when exhaust temperatures are at the industry reported temperatures is not known. The frequency and duration of events where the exhaust temperature would be below minimum requirements is also unknown, and important to the feasibility of the exhaust aftertreatment.

Physical configuration also places constraints on exhaust aftertreatment design. CRDPFs in particular are significantly larger than typical exhaust system components. Exhaust aftertreatment must be located near the engine to maximize the use of available exhaust heat. However, the exhaust system cannot interfere with the safe use of the equipment. This may be less of a problem for drilling rigs and hydraulic fracturing equipment than for mobile machinery since they are physically static during drilling or hydraulic fracturing. Physical configuration issues are more difficult to address when retrofitting existing equipment than when designing new equipment.

In the event that CRDPFs are not feasible for a specific application, DOCs may provide a feasible intermediate level of control. Exhaust aftertreatment consisting of SCR and DOCs has been retrofitted to Caterpillar 3512 generator set engines used on drill rigs in Wyoming (6).

Emissions of Nitrogen Dioxide

Nitrogen Dioxide (NO_2) is not explicitly regulated via EPA engine emissions standards. It is a component of the regulated pollutant NO_X. However, primary NO_2 emissions are a concern in the Marcellus Shale evaluation since for the evaluation of the new 1 hour NO_2 standard, specific emission factor estimates are necessary to assure that modeling results account for the NO_2 portion of the emissions.

Conventional information indicates that roughly 5% of NO_X emissions from internal combustion engines are NO_2; the balance are NO. However, European researchers have noted that ambient NO_2 concentrations have not been declining despite declining NO_X emissions from engines and vehicles. This has led to some investigation of the NO_2 fraction of primary NO_X emissions from highway vehicles. The most comprehensive summary is by Grice, et al (7), who needed the data for model inputs. These researchers found that the conventional use of 5% NO_2 holds for gasoline engines. The NO_2 fraction for diesel engines varies for different emissions control technologies, but is always greater than 5%. The data are summarized based on European emissions standards which must be translated into aftertreatment technology level.

NO_2 fractions for diesels range between 10% and 55% (7). EURO II engines, which have no exhaust aftertreatment, have an NO_2 fraction of 11%. This NO_2 fraction is used for Tier 1, Tier 2, and Tier3 engines with no retrofitted aftertreatment. For particulate trap equipped EURO III engines the NO_2 fraction is 35%. This NO_2 fraction is used for cases with either a DOC or a CRDPF either standard or retrofitted. The oxidation reactions in DOCs oxidize some NO to NO_2 along with the desired oxidation of hydrocarbons and particulate carbon. Indeed, oxidation catalysts are placed ahead of CRDPFs to produce NO_2 for use in oxidizing particulate matter to regenerate the PM trap. NO_2 oxidizes carbon at a lower temperature than O_2.

Finally, Grice et. al. chose to use a NO_2 fraction of 10% for engines equipped with SCR (EURO IV and later). However, the data for the SCR equipped engines was particularly sparse. This uncertainty is discussed further below.

For light duty vehicles equipped with NO_X aftertreatment an NO_2 fraction of 55% was reported. Light duty vehicle NO_X control generally avoids SCR, with its requirement that the operator maintain the urea supply. These alternative NO_X aftertreatment technologies have not proven viable for heavy duty truck engines, never mind the even larger engines to be used in Marcellus Shale drilling and hydraulic fracturing. Thus the 55% NO_2 fraction does not have any applicability here.

Table 4 below summarizes the recommended NO_2 fractions.

Table 4. NO_2 Emissions as Fraction of NO_X Emissions

Technology	**Fraction NO_2 (in %)**
No Exhaust Aftertreatment	11
Diesel Oxidation Catalyst or Particulate Trap	35
SCR (with or without DOC or CRDPF)	10 (see text)

Specifying a single NO_2 fraction for an engine technology is clearly a simplification. Researchers have documented variation in the NO_2 fraction depending on engine load (8) and exhaust temperature (9). The NO_2 fractions in Table 4 for engines without SCR could be low for engines operated at low loads and low exhaust temperatures. They appear to better reflect the emissions at higher loads more in line with the operations expected during drilling and hydraulic fracturing.

Given the particularly high level of uncertainty regarding the NO_2 fraction when SCR is used, a review of the chemistry involved might help. SCR generally converts NO_X to N_2. There are several different reactions involved (10), (11), (12). One of these reactions, the "fast" SCR reaction, is much faster (and has lower minimum temperature requirements) than the others.

$$2NH_3 + NO + NO_2 \rightarrow 2N_2 + 3H_2O$$

The fast SCR reaction generally goes to completion before any of the other reactions become significant. This leads to a desire to have a NO_2 fraction near 50% at the SCR reactor inlet.

However, given variations in the NO_2 consumption by a CRT and variations in engine load and engine out exhaust gas composition, consistently providing the SCR reactor with a 50:50 NO_2 to NO ratio would be quite difficult.

As long as the exhaust gases remain in the SCR reactor after the fast SCR reaction has exhausted one of the NO_X species, other chemical reactions will continue to reduce NO_X. The reaction for NO produces nitrogen and water. Several competing reactions are possible for NO_2. Some of these produce ammonium nitrate or nitrous oxide in addition to nitrogen.

Another concern with SCR is "ammonia slip," the emission of ammonia injected into the exhaust stream but not consumed. Oxidation catalysts are employed after SCR reactors to oxidize ammonia to nitrogen. This catalyst could also oxidize NO to NO_2. Thus, it cannot be completely ruled out that NO_X emissions from SCR equipped engines may consist of more than 10% NO_2, possibly with an upper bound of 35%. However, further review of the literature regarding the chemistry of ammonia slip catalysts leads to the conclusion that oxidation of NO to NO_2 is not a major concern. The desired reaction in the ammonia slip catalyst is the oxidation of ammonia to nitrogen and water. Competing reactions form NO and N_2O, but not NO_2 (13). The fate of NO in an ammonia slip catalyst is to react with ammonia and form N_2O. NO_2 production would likely only begin if the ammonia was exhausted. The chemical reaction mechanism of ammonia oxidation is well known, it is an intermediate step in the industrial production of nitric acid (14). Given that there is no apparent path to NO_2 formation as long as NH_3 is present, greater confidence can be placed in a NO_2 emission estimate of 10% of NO_X for SCR equipped engines.

Thus, actual data summarized by Grice et. al., although sparse, currently suggests that we consider the DOC/CRDPF NO_2 fraction of 10% as the appropriate factor. Regardless of the actual NO_2 fraction of the NO_X emissions from a SCR equipped engine (retrofitted or standard), SCR will provide the lowest NO_2 and NO_X emissions achievable with diesel engines.

Emission Rates for Various Emissions Standards Tiers & Exhaust Aftertreatment Retrofit Options

Considering the different Tiers of engine standards, the variety of possible exhaust aftertreatment retrofits, and the uncertainty in the NO_2 fraction of NO_X emissions from SCR equipped engines, there are in excess of 20 different emissions cases possible. Calculations were performed by Barnes (15) (16), but only the pertinent part of these results are presented in Tables 5 and 6.

These emissions rates are estimated from the relevant U.S. EPA standards presented in Tables 1 and 2. In cases where a NO_X + HC standard was promulgated, the standard is apportioned 90% NO_X, 10% HC. Effectiveness of exhaust aftertreatment retrofits are based on Table 3. Where the claimed retrofit effectiveness reduces an emission rate below a subsequent standard expected to require the same exhaust aftertreatment technology, the subsequent standard (the higher number) is used as the emissions rate. NO_2 emission rates are calculated from NO_X emission rates using factors presented in Table Four. For SCR-equipped engines the NO_2 fraction of 10 % of the NO_X emissions is presented. Note that for Tier 4 engines above 750 hp a case where SCR is standard (and thus cannot be retrofitted) is presented in addition to the original assumption that SCR would not be utilized to meet the 2.6 g/bhp*hr NO_X standard.

Table 5. Emissions Factors for Engines between 600 and 750 Horsepower

Air Drilling Engines

Standard	**Effective Year**	**Retrofit**	**PM (g/bhp*hr)**	**NO_X (g/bhp*hr)**	**HC (g/bhp*hr)**	**NO_2 (g/bhp*hr)**
Tier 1	1996	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2002	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 3	2006	None	0.15	2.7	0.3	0.297
		DOC	0.105	2.7	0.14	0.945
		CRDPF	0.03	2.7	0.14	0.945
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2011	None	0.01	1.35	0.14	0.473
		SCR	0.01	0.3	0.14	0.03
Tier 4	2014	None	0.01	0.3	0.14	0.03

Table 6. Emissions Factors for Engines Greater than 750 Horsepower

Drilling Rig and Hydraulic Fracturing Engines (Updated 2012)

Standard	**Effective Year**	**Retrofit**	**PM (g/bhp*hr)**	**NO_X (g/bhp*hr)**	**HC (g/bhp*hr)**	**NO_2 (g/bhp*hr)**
Tier 1	2000	None	0.4	6.9	1.0	0.759
		DOC	0.28	6.9	0.14	2.415
		CRDPF	0.06	6.9	0.14	2.415
		SCR-DPF	0.06	0.69	0.14	0.069
Tier 2	2006	None	0.15	4.32	0.48	0.475
		DOC	0.105	4.32	0.14	1.512
		CRDPF	0.03	4.32	0.14	1.512
		SCR-DPF	0.03	0.432	0.14	0.043
Tier 4 interim	2011	None	0.075	2.6	0.3	0.91
		CRDPF	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4	2015	None	0.03	2.6	0.14	0.91
		SCR-DPF	0.03	0.3	0.14	0.03
Tier 4 SCR Standard		None	0.03	2.6	0.14	0.26
Tier 4 Generator Set		None	0.02	0.5	0.14	0.05

Natural Gas Engines

For the most part, industry uses diesel engines for oil and gas drilling and hydraulic fracturing operations. Natural gas fired engines have been used in some instances. Natural gas engines must either be spark-ignition or a pilot fuel (generally diesel fuel) is necessary to initiate compression ignition (17). The latter are referred to as “dual-fueled.”

Large nonroad spark-ignition engines are certified under 40 CFR Part 1048. Since 2007 these engines have been certified to Tier 2 standards. Note that this is not the same Tier 2 as the nonroad compression-ignition standards referenced in Tables 1 and 2 above. Manufacturers have a choice of six different NO_X + HC standards, depending on the choice of carbon monoxide standard. In keeping with the methodology used above for diesel engines, the most lenient NO_X + HC standards serve as the basis for conservative emission factors.

The only relevant standard is the NO_X + HC standard. Additional information is necessary to derive, NO_X, PM, hydrocarbon, and NO_2 emission factors. This is provided by data published by the National Renewable Energy Laboratory regarding comparative testing of natural gas fueled trucks and buses versus comparable diesel fueled vehicles (18) (19). These limited data suggest that approximately 95% of the total NO_X and nonmethane hydrocarbon (the hydrocarbon measure specified in Part 1048 for natural gas fueled engines) is NO_X. NO_2 emissions are approximately 17% of total NO_X emissions. In the absence of PM standards the most stringent diesel PM standard from Table 2 is used. In the bus testing referenced in (19) the natural gas buses had PM emissions comparable to particulate trap equipped diesels. Emission factors for natural gas fueled spark-ignition engines are summarized in Table 7.

Table 7. Emission Factors for Natural Gas Fueled Spark-Ignition Engines (New 2012)

Standard	**Effective Year**	**PM (g/bhp*hr)**	**NO_X (g/bhp*hr)**	**HC (g/bhp*hr)**	**NO_2 (g/bhp*hr)**
Tier 2	2007	0.03	1.9	0.1	0.32

Duel fueled compression-ignition engines would be certified to the same standards as diesel engines of the same model year and horsepower class. They also can be operated solely on diesel fuel. Consequently emission factors derived for diesel engines would apply equally to duel fueled engines.

Summary

Between 2000 and 2015 nonroad engines will have gone through four or five (depending on engine power) different sets of emissions standards. PM mass reduction over this timeframe will be 93% for the largest engines and 98% for engines rated between 600 and 750 horsepower. NO_X emissions will be reduced 96% for the 600 to 750 horsepower engines, but only 62% for the larger engines. Much of these emissions reductions can be achieved without premature replacement of older engines by retrofitting exhaust aftertreatment to these engines. However, successful retrofits are dependent on the details of the engines and duty cycles involved, and have not been verified for drilling and hydraulic fracturing engines. An additional consideration with these retrofits is that PM aftertreatment in the absence of SCR will increase NO_2 emissions.

This concern also applies to current and future Tier 4 engines which may have PM aftertreatment but not NO_X aftertreatment.

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Appendix 18B

Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts By Selected Catalytic Reduction (SCR) Treatment

Updated/revised 2015

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Supplemental Generic Environmental Impact Statement

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Cost Analysis of Mitigation of NO_2 Emissions and Air Impacts by Selective Catalytic Reduction (SCR) Treatment

1. Introduction

Equipping fracturing engines with post-combustion NO_X control equipment could be a potential option for mitigating the modeled exceedances of the 1 hour NO_2 National Ambient Air Quality Standard. Selective Catalytic Reduction (SCR) is a proven technology for reducing oxides of nitrogen (NO_X) emissions from mobile and stationary combustion sources. Although SCR systems have not been applied to fracturing engines, it may be possible to adapt the technology to this class of engines. This technology involves the use of a urea solution (32.5 percent urea) which converts NO_X to nitrogen gas via a catalyst.

An estimate of the mitigation costs based on costs for stationary engines[1] is presented in this appendix. The purpose of these estimates is to determine the cost per ton of NO_X removal for a relative comparison to cost thresholds used by the Department for NO_X RACT purposes at stationary sources.[2] Any reference to specific manufacturers (in footnotes) does not constitute an endorsement, but merely presents the specific information source.

The remainder of this appendix is divided into three sections. First, an estimate is developed regarding how many jobs and how many hours a hydraulic fracturing engine could be used each year in Section 2. In the third section of the appendix, the costs of installing and operating a SCR system on a typical 2250 hp hydraulic fracturing engine are presented. In the fourth section, an estimate of the cost per ton of NO_X removed from the exhaust stream is presented for each engine tier.

2. Operation of Hydraulic Fracturing Engines

According to ALL Consulting, hydraulic fracturing engines will be used at any given well pad for no more than 14 days. Mobilization and de-mobilization activities are expected to take a total of four days. Hydraulic fracturing activities are expected to take ten days per well pad (five days per well).[3] At most, a hydraulic fracturing engine could be used for 26 jobs per year. Allowing for additional travel time, maintenance and vacations, the Department is assuming an engine will be used for approximately 20 jobs per year in the Marcellus play. Further, it was assumed that these engines will be used for a maximum of five hydraulic fracturing events per day and will operate two hours per event at their maximum loading and emissions.[4] Therefore, a hydraulic fracturing engine could be used up to 2,000 hours per year at the maximum load:

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1 Hydraulic fracturing engines are considered nonroad sources.
2 See: http://www.dec.ny.gov/regs/4217.html
3 "NY DEC SGEIS Information Requests", ALL Consulting, September 16, 2010, page 39.
4 "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, page 9.

(20 jobs/year)(10 days/job)(5 hydraulic fracturing events/day)(2 hours/hydraulic fracturing event) = 2,000 hours/year

3. Reduction of Oxides of Nitrogen and Costs

Selective catalytic reduction (SCR) is a proven technology for reducing NO_X emissions. The Department is assuming that this technology is the most likely post-combustion control that could potentially be used to reduce NO_X emissions from hydraulic fracturing engines (see Appendix 20). The Department considered capital, periodic and annual costs in the cost estimates discussed in this section.

Capital Costs

The capital cost for a SCR system was assumed to be $80 per hp.[5] Installation costs were assumed to be 60 percent of the system cost.[6] Taxes were assumed to be eight (8) percent of the system cost. The estimated capital cost for a typical 2250 hp hydraulic fracturing engine is $302,400 as detailed below:

System Cost:	$180,000
Installation:	$108,000
Taxes:	$ 14,400
Total:	$302,400

Periodic Costs

The periodic costs considered by the Department were for replacing SCR catalysts every five years.[7] It was assumed that the replacement costs were seven (7) percent of the system costs[8] and installation 60 percent of the replacement cost. The periodic costs (at year 5) were estimated to be $20,160 as detailed below:

Catalyst Replacement:	$12,600
Installation:	$ 7,560
Total:	$20,160

5 CARB 2010. Regulatory Analysis for Revisions to Stationary Diesel Engine Air Toxic Control Measure. Appendix B. Analysis of Technical Feasibility and Costs of Aftertreatment Controls on Emergency Diesel Engines.

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

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

8 E-mail from Chad Whiteman (Institute of Clean Air Companies) to John Barnes dated November 27, 2007 and e-mail from Wilson Chu (Johnson-Matthey) to John Barnes dated January 24, 2008.

Annual Costs

The quantity of reagent used depends upon the amount of NO_X coming from the engine. The control efficiency for SCRs was assumed to be 90 percent for engines. The emission rates factored into this analysis are presented in Table 1 (see Appendix 20). Further, it was assumed that hydraulic fracturing engines will be operated at 50 percent of capacity.[9] The urea requirement for each pound of NO_X treated in an SCR is 0.2088 gallons.[10]

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

Tier #	NO_X (without control)[11] (g/bhp-h)	NO_X (with control) g/bhp-h
2	4.32	0.43
Interim 4 (I4)	2.60	0.26
4	2.60	0.26

The urea requirements range from 1.21 gallons per hour (gal/h) for a Tier 4 engine to 2.01 gal/h for a Tier 2 engine. The estimated cost of urea is \$3.67 per gallon.[12]

In addition to the reagent requirements, annual insurance costs were estimated to be one (1) percent of the system cost[13] and maintenance costs were assumed to be six (6) percent of the system cost.[14] A summary of the annual costs is presented below:

	Tier 2	Tier I4	Tier 4
Reagent:	\$14,800	\$ 8,900	\$ 8,900
Insurance:	\$ 3,000	\$ 3,000	\$ 3,000
Maintenance:	\$18,100	\$18,100	\$18,100
Total:	\$35,900	\$30,000	\$30,000

Annualized Cost

A discount rate of seven (7) percent was used to convert the above costs into an equivalent annual cost for a 10-year horizon. The estimated annualized costs are presented in the next section.

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9 "Horizontally Drilled/High-Volume Hydraulically Fractured Wells, Air Emissions Data", August 26, 2009, p. 10.

10 E-mail from Michael Baran (Johnson Matthey) to John Barnes, April 17, 2008.

11 See Appendix 20. The values in the second column of Table 1 are assumed to be the NO_x emissions in the exhaust gas coming from the engine chamber.

12 E-mail from Wilson Chu (Johnson Matthey) to John Barnes (NYSDEC) dated January 24, 2008. Also factored was Consumer Price Index data: www.bls.gov/cpi/cpid0801.pdf and www.bls.gov/cpi/cpid0211.pdf.

13 Plant Design and Economics for Chemical Engineers, Third Edition, M.S. Peters and K. D. Timmerhaus, 1980, page 202.

14 Ibid, page 200.

4. Cost Effectiveness Analysis

The cost effectiveness (cost per ton of NO_X treated) of applying SCR controls on Tier 2, I4 and 4 hydraulic fracturing engines is presented in Table 2. .Hydraulic fracturing engines equipped with SCRs will have emission rates ranging from 0.26 g/bhp-h (Tier 4) to 0.43 g/bhp-h (Tier 2). The estimated cost per ton of NO_X control is greater than the Department's $5,000 per ton threshold for NO_X RACT (Reasonably Available Control Technology – Subpart 227-2) used to determine cost-effectiveness of controls at major stationary sources.

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

Engine Tier	Annualized Cost	NO_X Removed (tons)	Cost Effectiveness (ton^{-1})
2	$81,050	9.64	$ 8,400
I4	$75,170	5.80	$12,950
4	$75,170	5.80	$12,950

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Appendix 18C

Regional On-Road Mobile Source Emission Estimates from EPA's MOVES Model and Single-Pad PM2.5 Estimates from MOBILE 6 Model

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2007 Annual Mobile Source Emissions

MOVES 2010a Based Inventory Runs

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

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

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

Estimated additional mobile source emissions resulting from additional VMT associated with proposed gas drilling *					
NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)	(Tons/Yr)
686.7	70.0	2.5	34.4	33.3	668.6
Well pad emissions assuming total emissions split equally across all					
0.28	0.03	0.00	0.01	0.01	0.27

Percentage increase in emissions assuming all wells operating					
NOX	VOC	SO_2	PM_{10} Total	PM_{25} Total	CO
0.66%	0.17%	0.33%	0.79%	0.80%	0.11%

* Does NOT include Evaporative emissions processes

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

Vehicle Trip Emissions

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

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

Vehicle Idle Emissions

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

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

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

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

NEW YORK STATE OF OPPORTUNITY | Department of Environmental Conservation

Appendix 19

Greenhouse Gas (GHG) Emissions

Final

Supplemental Generic Environmental Impact Statement

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Part A

GHG Tables

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GHG Tables (Revised July 2011, following replaces tables released in September 2009)

Table GHG-1 – Emission Rates for Well Pad[1]

Emission Source/ Equipment Type	CH_4 EF	CO_2 EF	Units	EF Reference[2]
Fugitive Emissions				
Gas Wells				
Gas Wells	0.014	0.00015	lbs/hr per well	Vol 8, page no. 34, table 4-5
Field Separation Equipment				
Heaters	0.027	0.001	lbs/hr per heater	Vol 8, page no. 34, table 4-5
Separators	0.002	0.00006	lbs/hr per separator	Vol 8, page no. 34, table 4-5
Dehydrators	0.042	0.001	lbs/hr per dehydrator	Vol 8, page no. 34, table 4-5
Meters/Piping	0.017	0.001	lbs/hr per meter	Vol 8, page no. 34, table 4-5
Gathering Compressors				
Large Reciprocating Compressor	29.252	1.037	lbs/hr per compressor	GRI - 96 - Methane Emissions from the Natural Gas Industry, Final Report
Vented and Combusted Emissions				
Normal Operations				
1,775 hp Reciprocating Compressor	not determined	1,404.716	lbs/hr per compressor	6,760 Btu/hp-hr, 2004 API, page no. 4-8
Pneumatic Device Vents	0.664	0.024	lbs/hr per device	Vol 12, page no. 48, table 4-6
Dehydrator Vents	12.725	0.451	lbs/MMscf throughput	Vol 14, page no. 27
Dehydrator Pumps	45.804	1.623	lbs/MMscf throughput	GRI June Final Report
Blowdowns				
Vessel BD	0.00041	0.00001	lbs/hr per vessel	Vol 6, page no. 18, table 4-2
Compressor BD	0.020	0.00071	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Compressor Starts	0.045	0.00158	lbs/hr per compressor	Vol 6, page no. 18, table 4-2
Upsets				
Pressure Relief Valves	0.00018	0.00001	lbs/hr per valve	Vol 6, page no. 18, table 4-2

[1] Adapted from Exhibit 2.6.1, ICF Incorporated, LLC. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs*, Agreement No. 9679, August 2009., pp 34-35.
[2] Unless otherwise noted, all emission factors are from the Gas Research Institute, *Methane Emissions from the Natural Gas Industry*, 1996. Available at: epa.gov/gasstar/tools/related.html.

Table GHG-2 – Drilling Rig Mobilization, Site Preparation and Demobilization – GHG Emissions

	Single Vertical, Single Horizontal or Four-Well Pad[3]				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation [4]	432	NA	NA	4	NA
Drill Pad and Road Construction [5]	NA	48 hours	NA	11	NA
Total Emissions	432	NA	NA	15	NA

Table GHG-3 – Completion Rig Mobilization and Demobilization – GHG Emissions

	Single Vertical, Single Horizontal or Four-Well Pad				
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Vented Emissions (tons CH_4)**	**Combustion Emissions Light Truck & Heavy Truck Combined Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Completion Rig[6]	432	NA	NA	4	NA
Total Emissions	432	NA	NA	4	NA

[3] Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered.
[4] ALL Consulting, 2011, Exhibit19B.
[5] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[6] ALL Consulting, 2011, Exhibit19B. Completion rig mobilization likely less than that for drilling rig but for simplification assumed the same.

Table GHG-4 – Well Drilling – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[7]	788	NA	NA	NA	9	NA
Power Engines[8]	NA	132 hours	1	NA	74	NA
Circulating System[9]	NA	132 hours	1	negligible	NA	negligible
Well Control System[10]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	83	negligible

[7] ALL Consulting, 2011, Exhibit 20B.

[8] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

[9] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.

[10] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-5 – Well Drilling – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[11]	2,298	NA	NA	NA	26	NA
Power Engines[12]	NA	300 hours	1	NA	168	NA
Circulating System[13]	NA	300 hours	1	negligible	NA	negligible
Well Control System[14]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	194	negligible

[11] ALL Consulting, 2011, Exhibit19B.
[12] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[13] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[14] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-6 – Well Drilling – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[15]	9,192	NA	NA	NA	104	NA
Power Engines[16]	NA	1,200 hours	1	NA	672	NA
Circulating System[17]	NA	1,200 hours	1	negligible	NA	negligible
Well Control System[18]	NA	As needed	1	negligible	negligible	negligible
Total Emissions	NA	NA	NA	negligible	776	negligible

[15] ALL Consulting, 2011, Exhibit19B.
[16] Power Engines include rig engines, air compressor engines, mud pump engines and electrical generator engines. Assumed 50 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[17] Circulating system includes mud system piping and valves, mud-gas separator, mud pits or tanks and blooie line for air drilling.
[18] Well Control System includes well control piping and valves, BOP, choke manifold and flare line.

Table GHG-7 – Well Completion – Single Vertical Well GHG Emissions

	Single Vertical Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[19]	818	NA	1	NA	9	NA
Hydraulic Fracturing Pump Engines	NA	4,833 gallons[20]	1	NA	54	NA
Line Heater	NA	72 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	72 hours	1	NA	NA	negligible
Flare Stack[21]	NA	72 hours	1	12[22]	1,728[23]	NA
Rig Engines[24]	NA	12 hours	1	NA	4	NA
Site Reclamation[25]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[26]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	1,804	negligible

19 ALL Consulting, 2011, Exhibit 20B.
20 ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10. Assumed vertical job is one-sixth of high-volume job.
21 Assumed no use of reduced emission completion ("REC").
22 ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. . Vertical well not likely to produce at assumed rate due to reduced completion interval.
23 ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28. Vertical well not likely to produce at assumed rate due to reduced completion interval.
24 Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
25 Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
26 ALL Consulting, 2011, Exhibit 20B.

Table GHG-8 – Well Completion – Single Horizontal Well GHG Emissions

	Single Horizontal Well					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[27]	2,462	NA	1	NA	28	NA
Hydraulic Fracturing Pump Engines	NA	29,000 gallons[28]	1	NA	325	NA
Line Heater	NA	72 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	72 hours	1	NA	NA	negligible
Flare Stack[29]	NA	72 hours	1	12[30]	1,728[31]	NA
Rig Engines[32]	NA	24 hours	1	NA	7	NA
Site Reclamation[33]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation[34]	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	12	2,097	negligible

[27] ALL Consulting, 2011, Exhibit 19B.
[28] ALL Consulting, 2009. *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* Table 11, p. 10.
[29] Assumed no use of reduced emission completion ("REC").
[30] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[31] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, August 2009, NYSERDA Agreement No. 9679. p. 28.
[32] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[33] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[34] ALL Consulting, 2011, Exhibit 19B.

Table GHG-9 – Well Completion – Four-Well Pad GHG Emissions

	Four-Well Pad					
Emissions Source	**Light Truck & Heavy Truck Combined Fuel Use (gallons diesel)**	**Total Operating Hours or Fuel Use**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Transportation[35]	9,848	NA	NA	NA	112	NA
Hydraulic Fracturing Pump Engines	NA	116,000 gallons	NA	NA	1,300	NA
Line Heater	NA	288 hours	1	NA	negligible	NA
Flowback Pits/Tanks	NA	288 hours	1	NA	NA	negligible
Flare Stack[36]	NA	288 hours	1	48	6,912	NA
Rig Engines[37]	NA	96 hours	1	NA	28	NA
Site Reclamation[38]	NA	24 hours	NA	NA	6	NA
Transportation for Site Reclamation	280	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	48	8,361	negligible

[35] ALL Consulting, 2011, Exhibit 19B.
[36] Assumed no use of reduced emission completion ("REC").
[37] Assumed 25 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.
[38] Assumed 20 gallons of diesel fuel used per hour with 100% oxidation of fuel carbon to CO_2.

Table GHG-10 – First-Year Well Production – Single Vertical Well GHG Emissions[39]

	Single Vertical Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[40]	400	NA	NA	NA	1	NA
Wellhead	NA	8,376 hours[41]	1	NA	NA	negligible
Compressor	NA	8,376 hours	1	not determined	5,883[42] (&4[43])	123[44]
Line Heater	NA	8,376 hours	1	negligible	negligible	negligible
Separator	NA	8,376 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,376 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,376 hours	1	22[45]	3[46]	negligible
Dehydrator Pumps	NA	8,376 hours	1	80[47]	NA	negligible
Pneumatic Device Vents	NA	8,376 hours	3	9[48]	NA	negligible
Meters/Piping	NA	8,376 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	8,376 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[49]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	111	5,894	123

[39] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval.
[40] Assumed roundtrip of 40 miles.
[41] Calculated by subtracting total time required to drill and complete one vertical well (16 days) from 365 days.
[42] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[43] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[44] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[45] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[46] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[47] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[48] Emissions Factor (EF) of 0.664 lbs per hour.
[49] Assumed roundtrip of 40 miles.

Table GHG-11 – First-Year Well Production – Single Horizontal Well GHG Emissions[50]

	Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[51]	400	NA	NA	NA	1	NA
Wellhead	NA	7,944 hours[52]	1	NA	NA	negligible
Compressor	NA	7,944 hours	1	not determined	5,580[53] (&4[54])	122[55]
Line Heater	NA	7,944 hours	1	negligible	negligible	negligible
Separator	NA	7,944 hours		NA	negligible	negligible
Glycol Dehydrator	NA	7,944 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	7,944 hours	1	21[56]	3[57]	negligible
Dehydrator Pumps	NA	7,944 hours	1	76[58]	NA	negligible
Pneumatic Device Vents	NA	7,944 hours	3	9[59]	NA	negligible
Meters/Piping	NA	7,944 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	7,944 hours	1	negligible	NA	negligible
Production Brine Removal 44Truckloads[60]	1,760	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	106	5,591	122

[50] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[51] Assumed roundtrip of 40 miles.
[52] Calculated by subtracting total time required to drill and complete one horizontal well (34 days) from 365 days.
[53] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[54] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[55] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[56] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[57] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[58] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[59] Emissions Factor (EF) of 0.664 lbs per hour.
[60] Assumed roundtrip of 40 miles.

Table GHG-12 – First-Year Well Production – Four-Well Pad GHG Emissions[61]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Production Equipment 10 Truckloads[62]	1,600	NA	NA	NA	3	NA
Wellhead	NA	5,496 hours[63]	1	NA	NA	negligible
Compressor	NA	5,496 hours	1	not determined	3,860[64] (&3[65])	80[66]
Line Heater	NA	5,496 hours	1	negligible	negligible	negligible
Separator	NA	5,496 hours		NA	negligible	negligible
Glycol Dehydrator	NA	5,496 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	5,496 hours	1	58[67]	8[68]	negligible
Dehydrator Pumps	NA	5,496 hours	1	210[69]	NA	negligible
Pneumatic Device Vents	NA	5,496 hours	3	6[70]	NA	negligible
Meters/Piping	NA	5,496 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	5,496 hours	2	negligible	NA	negligible
Production Brine Removal 176 Truckloads[71]	7,040	NA	NA	NA	11	NA
Total Emissions	NA	NA	NA	274	3,885	80

[61] First-Year production is the production period in the first year after drilling and completion activities have been concluded. Assumed production 10 mmcfd per well.
[62] Assumed roundtrip of 40 miles.
[63] Calculated by subtracting total time required to drill and complete four horizontal wells (136 days) from 365 days.
[64] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[65] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[66] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[67] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[68] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[69] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[70] Emissions Factor (EF) of 0.664 lbs per hour.
[71] Assumed roundtrip of 40 miles.

Table GHG-13 – Post-First Year Annual Well Production – Single Vertical or Single Horizontal Well GHG Emissions[72]

	Single Vertical Well or Single Horizontal Well					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[73]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[74] (&5[75])	128[76]
Line Heater	NA	8,760 hours	1	negligible	negligible	negligible
Separator	NA	8,760 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,760 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,760 hours	1	23[77]	3[78]	negligible
Dehydrator Pumps	NA	8,760 hours	1	84[79]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[80]	NA	negligible
Meters/Piping	NA	8,760 hours	1	NA	NA	negligible
Vessel BD	NA	4 hours	4	negligible	NA	negligible
Compressor BD	NA	4 hours	4	negligible	NA	negligible
Compressor Starts	NA	4 hours	4	negligible	NA	negligible
Pressure Relief Valves	NA	4 hours	5	negligible	NA	negligible
Production Brine Tanks	NA	8,760 hours	1	negligible	NA	negligible
Production Brine Removal 50Truckloads[81]	2,000	NA	NA	NA	3	NA
Total Emissions	NA	NA	NA	116	6,164	128

72 Assumed production 10 mmcfd per well.
73 Hours in 365 days.
74 Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
75 Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
76 One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
77 Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
78 Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
79 Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
80 Emissions Factor (EF) of 0.664 lbs per hour.
81 Assumed roundtrip of 40 miles.

Table GHG-14 – Post-First Year Annual Well Production – Four-Well Pad GHG Emissions[82]

	Four-Well Pad					
Emissions Source	**Vehicle Miles Traveled (VMT)**	**Total Operating Hours**	**Activity Factor**	**Vented Emissions (tons CH_4)**	**Combustion Emissions (tons CO_2)**	**Fugitive Emissions (tons CH_4)**
Wellhead	NA	8,760 hours[83]	1	NA	NA	negligible
Compressor	NA	8,760 hours	1	not determined	6,153[84] (&5[85])	128[86]
Line Heater	NA	8,760 hours	1	negligible	negligible	negligible
Separator	NA	8,760 hours		NA	negligible	negligible
Glycol Dehydrator	NA	8,760 hours	1	negligible	negligible	negligible
Dehydrator Vents	NA	8,760 hours	1	93[87]	12[88]	negligible
Dehydrator Pumps	NA	8,760 hours	1	335[89]	NA	negligible
Pneumatic Device Vents	NA	8,760 hours	3	9[90]	NA	negligible
Meters/Piping	NA	8,760 hours	4	NA	NA	negligible
Vessel BD	NA	16 hours	8	negligible	NA	negligible
Compressor BD	NA	16 hours	8	negligible	NA	negligible
Compressor Starts	NA	16 hours	8	negligible	NA	negligible
Pressure Relief Valves	NA	16 hours	10	negligible	NA	negligible
Production Brine Tanks	NA	8,760 hours	2	negligible	NA	negligible
Production Brine Removal 200Truckloads[91]	8,000	NA	NA	NA	13	NA
Total Emissions	NA	NA	NA	437	6,183	128

[82] Assumed production 10 mmcfd per well.
[83] Hours in 365 days.
[84] Combustion emission, Emissions Factor (EF) of 1,404.716 lbs per hour.
[85] Fugitive emission, Emissions Factor (EF) of 1.037 lbs per hour.
[86] One compressor at Emissions Factor (EF) of 29.252 lbs per hour.
[87] Emissions Factor (EF) of 12.725 lbs. per mmcf throughput.
[88] Vented emission, Emissions Factor (EF) of 1.623 lbs per mmcf throughput.
[89] Emissions Factor (EF) of 45.804 lbs. per mmcf throughput.
[90] Emissions Factor (EF) of 0.664 lbs per hour.
[91] Assumed roundtrip of 40 miles.

Table GHG-15 – Estimated First-Year Green House Gas Emissions from Single Vertical Well

	Single Vertical Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[92]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	83	negligible	negligible	83
Well Completion including Hydraulic Fracturing and Flowback	1,804	12	300	2,104
Well Production	5,894	234	5,850	11,744
Total	8,660	246	6,150	14,810

Table GHG-16 – Estimated First-Year Green House Gas Emissions from Single Horizontal Well

	Single Horizontal Well			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[93]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	194	negligible	negligible	194
Well Completion including Hydraulic Fracturing and Flowback	2,097	12	300	2,397
Well Production	5,591	228	5,700	11,291
Total	8,761	240	6,000	14,761

Table GHG-17 – Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical Well or Single Horizontal Well

	Single Vertical Well or Single Horizontal Well[94]			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[95]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,164	244	6,100	12,264

---

[92] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[93] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[94] Assumed production 10 mmcfd per well. However, vertical well not likely to produce at assumed rate due to reduced completion interval, and therefore emission estimates are conservative for vertical well production.
[95] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Table GHG-18 – Estimated First-Year Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[96]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Drilling Rig Mobilization, Site Preparation and Demobilization	447	NA	NA	447
Completion Rig Mobilization and Demobilization	432	NA	NA	432
Well Drilling	776	negligible	negligible	776
Well Completion including Hydraulic Fracturing and Flowback	8,361	48	1,200	9,561
Well Production	3,885	354	8,850	12,735
Total	13,901	402	10,050	23,951

Table GHG-19 – Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Pad

	Four-Well Pad			
	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[97]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Well Production	6,183	565	14,125	20,300

[96] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).
[97] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

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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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Appendix 20

PROPOSED
Pre-Frac Checklist and Certification

Final

Supplemental Generic Environmental Impact Statement

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PRE-FRAC CHECKLIST AND CERTIFICATION

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

API Number:

Well Owner:

Planned Frac Commencement Date:

Yes	No	
☐	☐	Well drilled, cased and cemented in accordance with well permit, or in accordance with revisions approved by the Regional Mineral Resources Manager on the dates listed below and revised wellbore schematic filed in regional Mineral Resources office. <u>Approval Date & Brief Description of Approved Revision(s)</u> *(attach additional sheets if necessary)*
☐	☐	All depths where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations are recorded on the attached sheet. Additional sheets are attached which describe how any lost circulation zones were addressed.
☐	☐	Enclosed radial cement bond evaluation log and narrative analysis of such, or other Department-approved evaluation, and consideration of appropriate supporting data per Section 6.4 "Other Testing and Information" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009) verifies top of cement and effective cement bond at least 500 feet above the top of the formation to be fractured or at least 300 feet into the previous casing string. If intermediate casing was not installed, or if was not production casing was not cemented to surface, then provide the date of approval by the Department and a brief description of justification. <u>Approval Date & Brief Description of Justification</u> *(attach additional sheets if necessary)*
☐	☐	Per Section 7.1 "General" under the heading "Well Construction Guidelines" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009), a representative blend of the cement used for the production casing was bench tested in accordance with API 10A Specification for Cements and Materials for Well Cementing (Twenty-Fourth Edition, December 2010) and was found to be of sufficient strength to withstand the maximum anticipated treatment pressure during hydraulic fracturing operations.
☐	☐	If fracturing operations will be performed down casing, then the pre-fracturing pressure tests required by permit conditions will be conducted and fracturing operations will only commence if the tests are successful. Any unsuccessful test will be reported to the Department and remedial measures will be proposed by the operator and must be approved by the Department prior to further operations.
☐	☐	All other information collected while drilling, listed below, verifies that all observed gas zones are isolated by casing and cement and that the well is properly constructed and suitable for high-volume hydraulic fracturing.

PRE-FRAC CHECKLIST AND CERTIFICATION

Date and Brief Description of Information Collected
(attach additional sheets if necessary)

☐ ☐ Fracturing products used will be the same products identified in the well permit application materials or otherwise identified and approved by the Department.

I hereby affirm under penalty of perjury that information provided on this form is true to the best of my knowledge and belief. False statements made herein are punishable as a Class A misdemeanor pursuant to Section 210.45 of the Penal Law.

Printed or Typed Name and Title of Authorized Representative
Signature, Date

INSTRUCTIONS FOR PRE-FRAC CHECKLIST AND CERTIFICATION

The completed and signed form, and treatment plan must be received by the appropriate Regional office at least 3 days prior to the commencement of hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volume of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well (i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)). The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification*, and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing and 3) all other pre-frac notification requirements are met as specified elsewhere. **The well owner is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the pre-frac checklist.**

SIGNATURE SECTION

Signature Section - The person signing the *Pre-Frac Checklist And Certification* must be authorized to do so on the Organizational Report on file with the Division of Mineral Resources.

Appendix 21

Publicly Owned Treatment Works (POTWs) With Approved Pretreatment Programs

Final

Supplemental Generic Environmental Impact Statement

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Pretreatment Facilities and Associated WWTPs

Region	**Pretreatment Program**	**Facility**	**SPDES Number**
1	Nassau County DPW - this facility is tracked under Cedar Creek in PCS.	Inwood STP Bay Park STP ***Cedar Creek WPCP	NY0026441 NY0026450 NY0026859
	Glen Cove (C)	Glen Cove STP	NY0026620
	Suffolk DPW	Suffolk Co. SD #3 - Southwest	NY0104809
2	New York City DEP	Wards Island WPCP Owls Head WPCP Newtown Creek WPCP Jamaica WPCP North River WPCP 26th Ward WPCP Coney Island WPCP Red Hook WPCP Tallman Island WPCP Bowery Bay WPCP Rockaway WPCP Oakwood Beach WPCP Port Richmond WPCP Hunts Point WPCP	NY0026131 NY0026166 NY0026204 NY0026115 NY0026247 NY0026212 NY0026182 NY0027073 NY0026239 NY0026158 NY0026221 NY0026174 NY0026107 NY0026191
3	Suffern (V)	Suffern	NY0022748
	Orangetown SD #2		NY0026051
	Orange County SD #1	Harriman STP	NY0027901
	Newburgh (C)	Newburgh WPCF	NY0026310
	Westchester County	Blind Brook Mamaroneck New Rochelle Ossining Port Chester Peekskill Yonkers Joint	NY0026719 NY0026701 NY0026697 NY0108324 NY0026786 NY0100803 NY0026689
	Rockland County SD #1		NY0031895
	Poughkeepsie (C)	Poughkeepsie STP	NY0026255
	New Windsor (T)	New Windsor STP	NY0022446
	Beacon (C)	Beacon STP	NY0025976
	Haverstraw Joint Regional Sewer Board	Haverstraw Joint Regional Stp	NY0028533
	Kingston (C)	Kingston (C) WWTF	NY0029351
4	Amsterdam (C)	Amsterdam STP	NY0020290
	Albany County	North WWTF South WWTF	NY0026875 NY0026867
	Schenectady (C)	Schenectady WPCP	NY0020516
	Rennselaer County SD #1	Rennselaer County SD #1	NY0087971
5	Plattsburgh (C)	City of Plattsburgh WPCP	NY0026018
	Glens Falls (C)	Glens Fall (C)	NY0029050
	Gloversville-Johnstown Joint Board		NY0026042
	Saratoga County SD #1		NY0028240

Region	Pretreatment Program	Facility	SPDES Number
6	Little Falls (C)	Little Falls WWTP	NY0022403
	Herkimer County	Herkimer County SD	NY0036528
	Rome (C)	Rome WPCF	NY0030864
	Ogdensburg (C)	City of Ogdensburg WWTP	NY0029831
	Oneida County		NY0025780
	Watertown		NY0025984
7	Auburn (C)	Auburn STP	NY0021903
	Fulton (C)		NY0026301
	Oswego (C)	Westside Wastewater Facility Eastside Wastewater Facility	NY0029106 NY0029114
	Cortland (C)	LeRoy R. Summerson WTF	NY0027561
	Endicott (V)	Endicott WWTF	NY0027669
	Ithaca (C)		NY0026638
	Binghamton-Johnson City		NY0024414
	Onondaga County	Metropolitan Syracuse Baldwinsville/Seneca Knolls Meadowbrook/Limestone Oak Orchard Wetzel Road	NY0027081 NY0030571 NY0027723 NY0030317 NY0027618
8	Canandaigua (C)	Canandaigua STP	NY0025968
	Webster (T)	Walter W. Bradley WPCP	NY0021610
	Monroe County	Frank E VanLare STP Northwest Quadrant STP	NY0028339 NY0028231
	Batavia (C)		NY0026514
	Geneva (C)	Marsh Creek STP	NY0027049
	Newark (V)		NY0029475
	Chemung County	Chemung County SD #1 Chemung County - Elmira Chemung County - Baker Road	NY0036986 NY0035742 NY0246948
9	Middleport (V)	Middleport (V) STP	NY0022331
	North Tonawanda (C)		NY0026280
	Newfane STP (T)		NY0027774
	Erie County Southtowns	Erie County Southtowns Erie County SD #2 - Big Sister	NY0095401 NY0022543
	Niagara County	Niagara County SD #1	NY0027979
	Blasdell (V)	Blasdell	NY0020681
	Buffalo Sewer Authority	Buffalo (C)	NY0028410
	Amherst SD (T)		NY0025950
	Niagara Falls (C)		NY0026336
	Tonawanda (T)	Tonawanda (T) SD #2 WWTP	NY0026395
	Lockport (C)		NY0027057
	Olean STP (C)		NY0027162
	Jamestown STP (C)		NY0027570
	Dunkirk STP (C)		NY0027961

Mini-Pretreatment Facilities

Region	Facility	SPDES Number
3	Arlington WWTP	NY0026271
3	Port Jervis STP	NY0026522
3	Wallkill (T) STP	NY0024422
4	Canajoharie (V) WWTP	NY0023485
4	Colonie (T) Mohawk View WPCP	NY0027758
4	East Greenbush (T) WWTP	NY0026034
4	Hoosick Falls (V) WWTP	NY0024821
4	Hudson (C) STP	NY0022039
4	Montgomery co SD#1 STP	NY0107565
4	Park Guilderland N.E. IND STP	NY0022217
4	Rotterdam (T) SD2 STP	NY0020141
4	Delhi (V) WWTP	NY0020265
4	Hobart (V) WWTP	NY0029254
4	Walton (V) WWTP	NY0027154
7	Canastota (V) WPCP	NY0029807
7	Cayuga Heights (V) WWTP	NY0020958
7	Moravia (V) WWTP	NY0022756
7	Norwich (C) WWTP	NY0021423
7	Oak Orchard STP	NY0030317
7	Oneida (C) STP	NY0026956
7	Owego (T) SD#1	NY0022730
7	Owego WPCP #2	NY0025798
7	Sherburne (V) WWTP	NY0021466
7	Waverly (V) WWTP	NY0031089
7	Wetzel Road WWTP	NY0027618
8	Avon (V) STP	NY0024449
8	Bath (V) WWTP	NY0021431
8	Bloomfield (V) WWTP	NY0024007
8	Clifton Springs (V) WWTP	NY0020311
8	Clyde (V) WWTP	NY0023965
8	Corning (C) WWTP	NY0025721
8	Dundee STP	NY0025445
8	Erwin (T) WWTP	NY0023906
8	Holley (V) WPCP	NY0023256
8	Honeoye Falls (V) WWTP	NY0025259
8	Hornell (C) WPCP	NY0023647
8	Marion STP	NY0031569
8	Ontario (T) STP	NY0027171
8	Seneca Falls (V) WWTP	NY0033308
8	Walworth SD #1	NY0025704
9	Akron (V) WWTP	NY0031003
9	Arcade (V) WWTP	NY0026948
9	Attica (V) WWTP	NY0021849
9	East Aurora (V) STP	NY0028436
9	Gowanda (V)	NY0032093

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Appendix 22

POTW Procedures for Accepting High-Volume Hydraulic Fracturing Wastewater

Final

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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

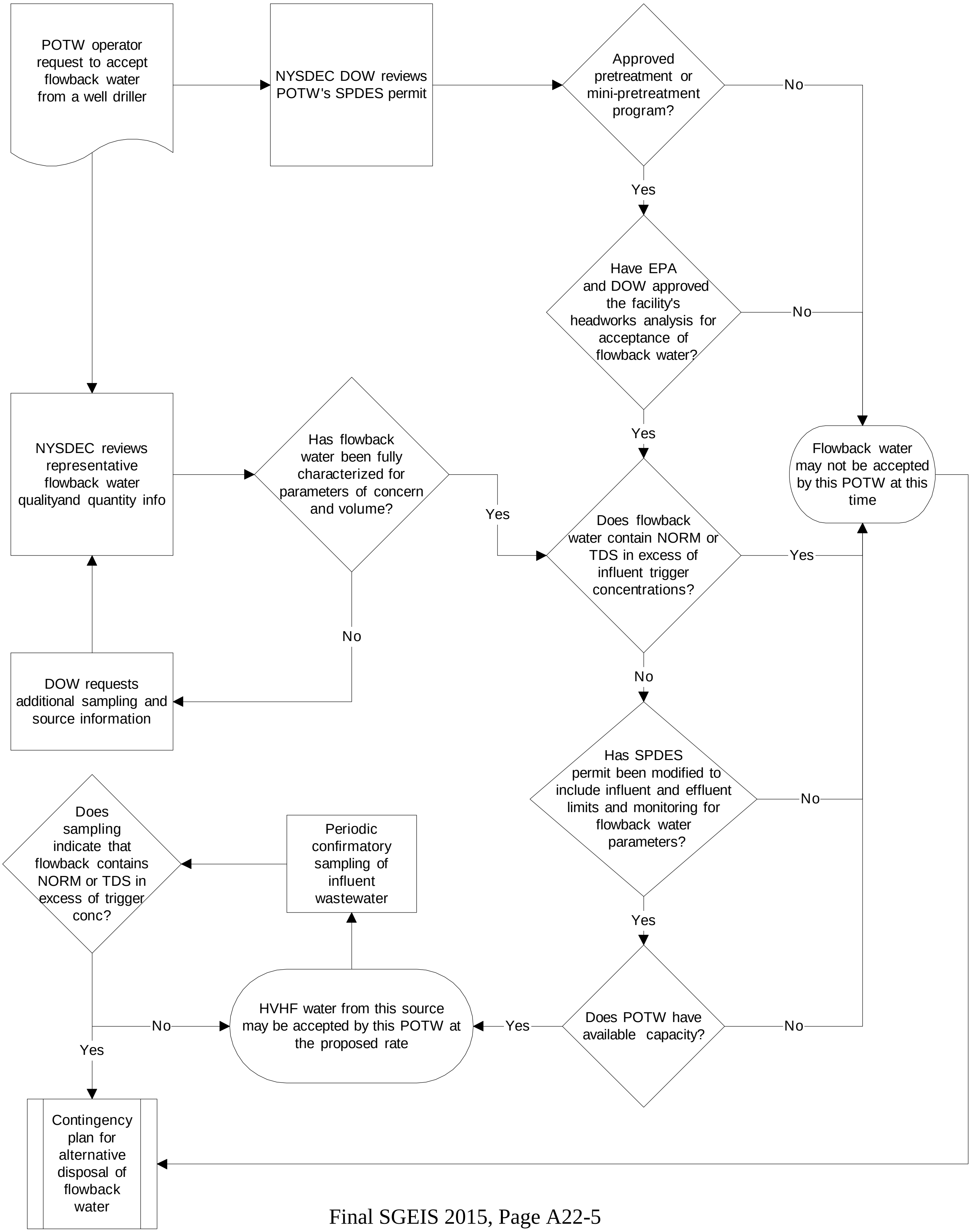
6. The Department will send a determination regarding the request to the permittee following the Division of Water and USEPA's analysis of the request. If the request is approved, the POTW may accept high-volume hydraulic fracturing wastewater from the requested source at the specified maximum concentrations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

Appendix 23

USEPA Natural Gas STAR Program

Final

Supplemental Generic Environmental Impact Statement

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TO: Peter Briggs, New York State Department of Environmental Conservation, Mineral Resources

FROM: Jerome Blackman, Natural Gas STAR International

DATE: September 1, 2009

RE: Natural Gas Star

This memo lists methane emission mitigation options applicable in exploration and production; in reference to your inquiry. Natural Gas STAR Partners have reported a number of voluntary activities to reduce exploration and production methane emissions, and major project types are listed and summarized below and may help focus your research as you review the resources available on the Natural Gas STAR website.

In addition to these practices and technologies is an article that lists the same and several more cost effective options for producers to reduce methane emissions. Please refer to the link below.

Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers
www.epa.gov/gasstar/documents/CaseStudy.pdf

Reduced Emission Completions
Traditionally, "cleaning up" drilled wells, before connecting them to a production sales line, involves producing the well to open pits or tankage where sand, cuttings, and reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Partners reported using a "green completion" method in which tanks, separators, dehydrators are brought on site to clean up the gas sufficiently for delivery to sales. The result is reducing completion emissions, creating an immediate revenue stream, and less solid waste.

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/greencompletions.pdf

BP Experience Presentation with Reduced Emission Completions
www.epa.gov/gasstar/documents/workshops/2008-annual-conf/smith.pdf

Green Completion Presentation from a Tech-Transfer Workshop in 2005 at Houston, TX
www.epa.gov/gasstar/documents/workshops/houston-2005/green_c.pdf

Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrator
In dehydrators, as triethylene glycol (TEG) absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). When the TEG is regenerated through heating, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. Many wells produce gas below the initial design capacity yet

TEG circulation rates remain two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Optimizing circulation rates reduces methane emissions at negligible cost. Installing flash tank separators on glycol dehydrators further reduces methane, VOC, and HAP emissions and saves even more money. Flash tanks can recycle typically vented gas to the compressor suction and/or used as a fuel for the TEG reboiler and compressor engine.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_flashtanks3.pdf

Dehydrator Presentation from a 2008 Tech-Transfer Workshop in Charleston, WV:
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/charleston_dehydration.pdf

Replacing Glycol Dehydrators with Desiccant Dehydrators

Natural Gas STAR Partners have found that replacing glycol dehydrators with desiccant dehydrators reduces methane, VOC, and HAP emissions by 99 percent and also reduces operating and maintenance costs. In a desiccant dehydrator, wet gas passes through a drying bed of desiccant tablets. The tablets pull moisture from the gas and gradually dissolve in the process. Replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to $9,232 per year in fuel gas, vented gas, operation and maintenance (O&M) costs, and reduce methane emissions by 444 thousand cubic feet (Mcf) per year.

Lessons Learned Document from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_desde.pdf

Directed Inspection and Maintenance

A directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.

Lessons Learned Documents from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/ll_dimgasproc.pdf
www.epa.gov/gasstar/documents/ll_dimcompstat.pdf

Partner Recommended Opportunity from the Natural Gas STAR website:
www.epa.gov/gasstar/documents/conductdimatremotefacilities.pdf

DI&M Presentation from a Tech-Transfer Workshop in 2008 at Midland, TX
www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland4.ppt

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Appendix 24

Key Features of USEPA Natural Gas STAR Program

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Key Features of USEPA Natural Gas STAR Program[1]

Complete information on the Natural Gas STAR Program is given in USEPA's web site (http://epa.gov/gasstar/index.html)

- Participation in the program is voluntary.
- Program outreach is provided through the web site, annual national two-day implementation workshop, and sector– or activity – specific technology transfer workshops or webcasts, often with a regional focus (approximately six to nine per year).
- Companies agreeing to join ("Partners") commit to evaluating Best Management Practices (BMP) and implementing them when they are cost-effective for the company. In addition, " …partners are encouraged to identify, implement, and report on other technologies and practices to reduce methane emissions (referred to as Partner Reported Opportunities or PROs)."
- Best Management Practices are a limited set of reduction measures identified at the initiation of the program as widely applicable. PROs subsequently reported by partners have increased the number of reduction measures.
- The program provides calculation tools for estimating emissions reductions for BMPs and PROs, based on the relevant features of the equipment and application.
- Projected emissions reductions for some measures can be estimated accurately and simply; for example, reductions from replacing high-bleed pneumatic devices with low-bleed devices are a simple function of the known bleed rates of the respective devices, and the methane content of the gas. For others, such as those involving inspection and maintenance to detect and repair leaks, emissions reductions are difficult to anticipate because the number and magnitude of leaks is initially unknown or poorly estimated.
- Tools are also provided for estimating the economics of emission reduction measures, as a function of factors such as gas value, capital costs, and operation and maintenance costs.
- Technical feasibility is variable between measures and is often site- or application- specific. For example, in the Gas STAR Lessons Learned for replacing high-bleed with low-bleed pneumatic devices, it is estimated that "nearly all" high-bleed devices can feasibly be replaced with low-bleed devices. Some specific exceptions are listed, including very large valves requiring fast and/or precise response, commonly on large compressor discharge and bypass controllers.
- Partners report emissions reductions annually, but the individual partner reports are confidential. Publicly reported data are aggregated nationally, but include total reductions by sector and by emissions reduction measure.

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

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Appendix 25

Reduced Emissions Completion (REC) Executive Summary

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Reduced Emissions Completions – Executive Summary[1]

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

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

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

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

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

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

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

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Appendix 26

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

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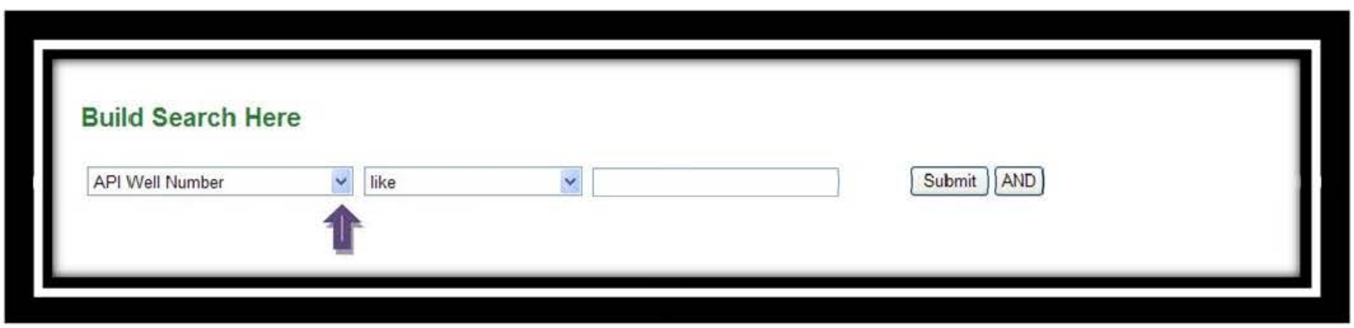
How to Use the Online Searchable Database to Find Information about Recently Filed Permit Applications

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

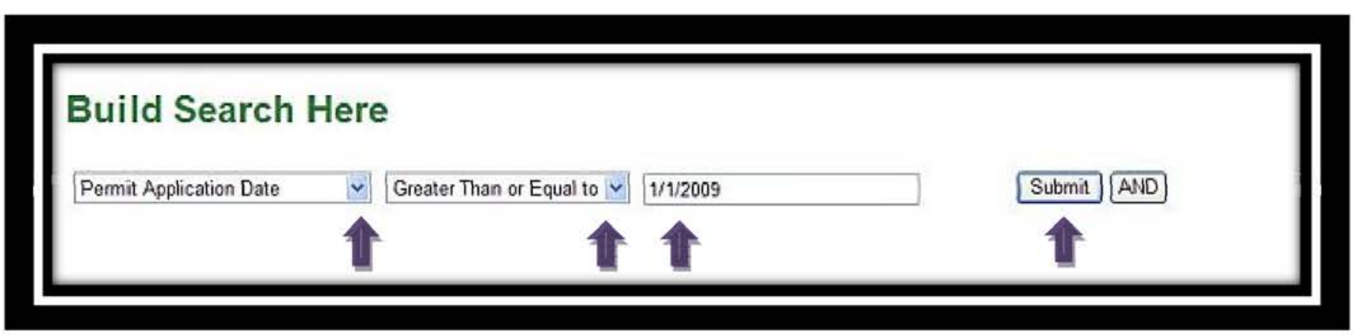
How to Conduct a Simple Search

1. Select Wells Data to begin your search.

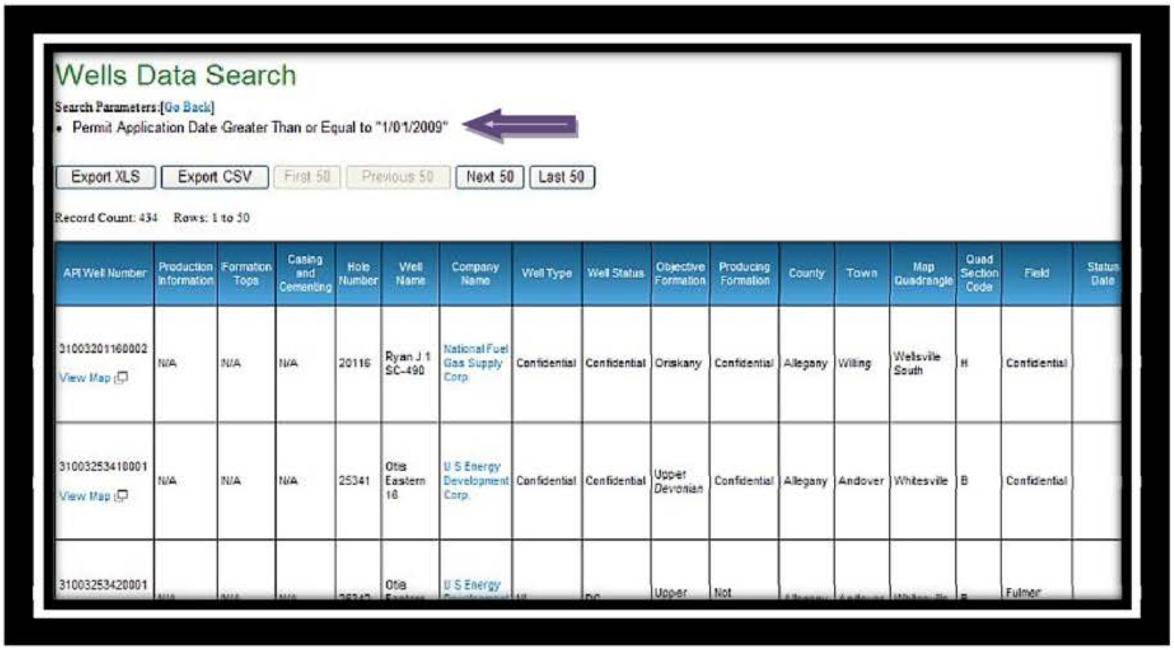
2. Select your search criteria. Use the drop down arrow next to API Number to select your search criteria.



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



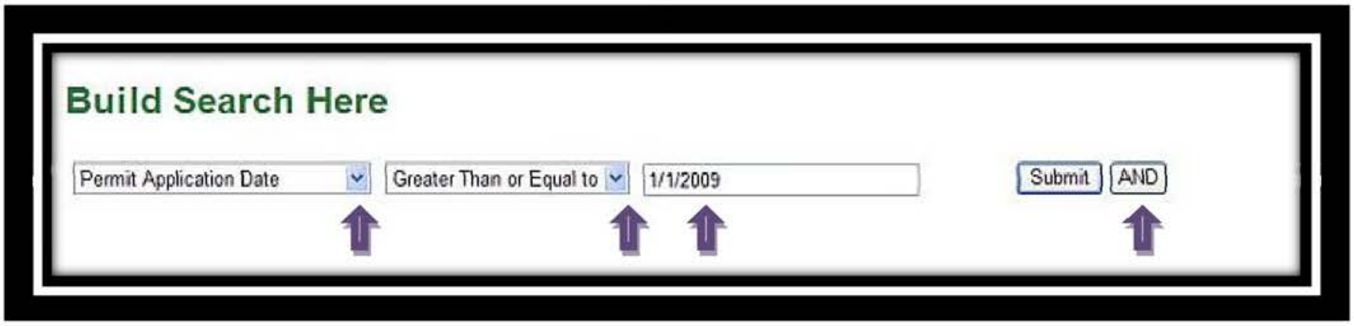
4. View results. By selecting the View Map hyperlink, a new window will open to Google Maps showing the well location along with latitude and longitude information. The results from your query can be saved to your computer as either an Excel spreadsheet (xls) or as a comma separated value file (csv)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



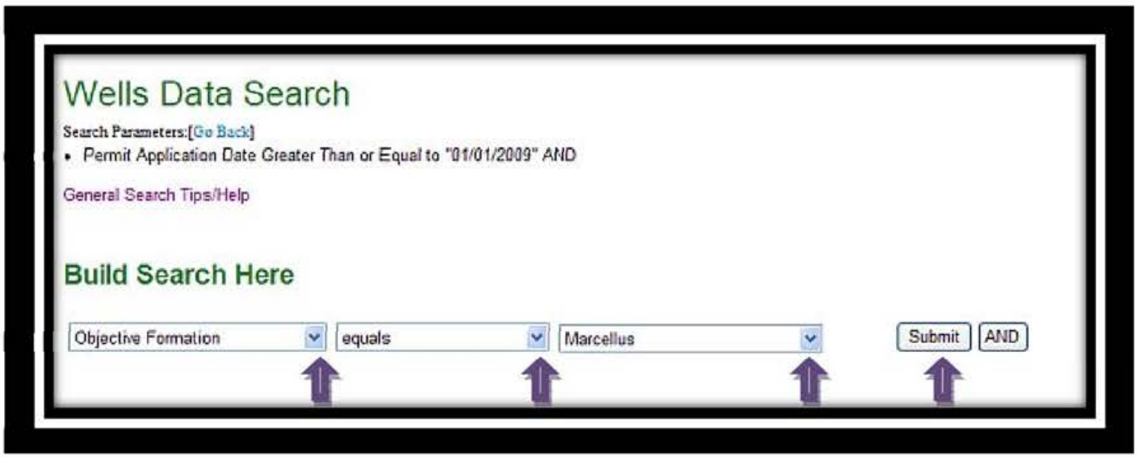
How to Narrow or Expand Your Search Utilizing the AND Button

1. Select Wells Data to begin your search.

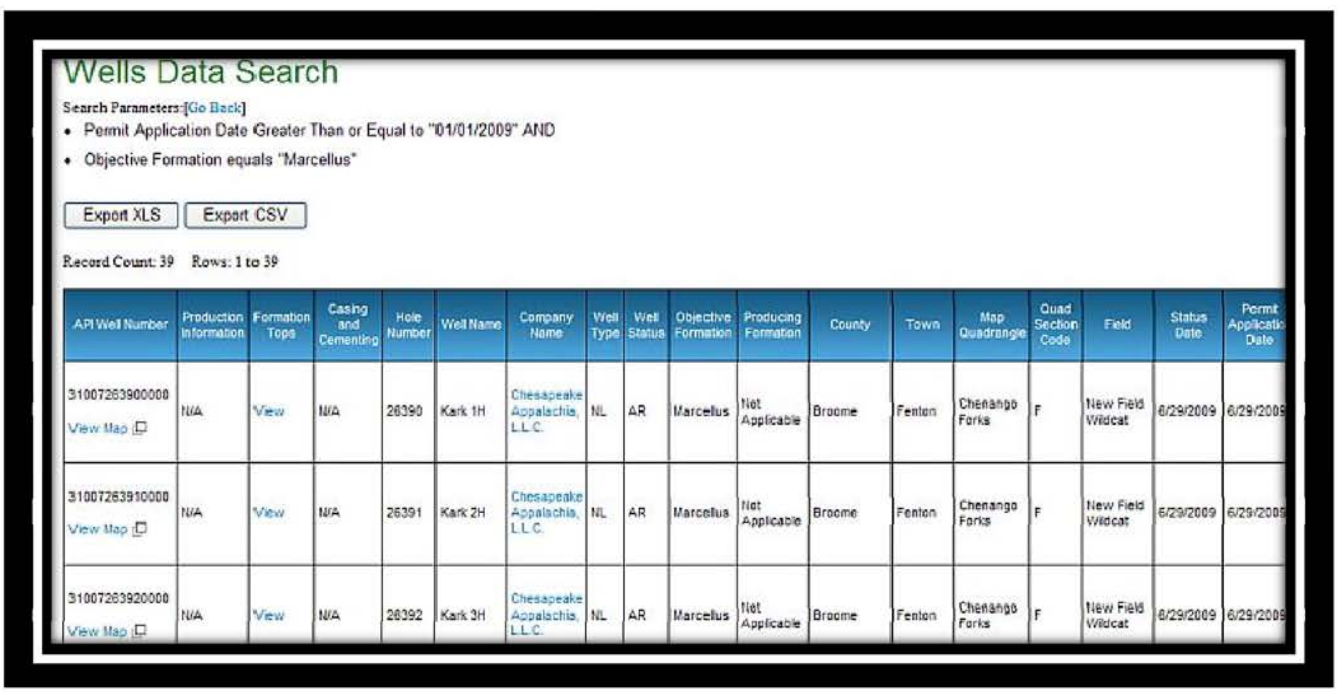
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permit applications filed in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Click the Submit button.



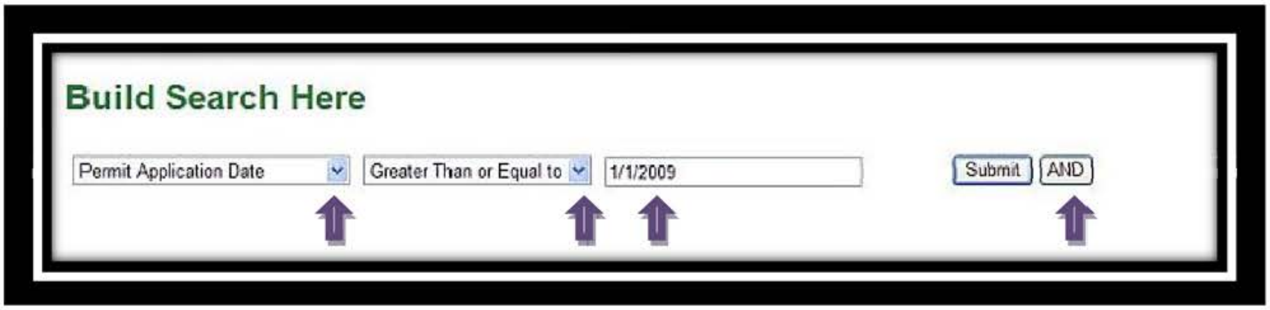
4. View Results.



How to Narrow Your Search to Applications Submitted For a Specific County

1. Select Wells Data to begin your search.

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



3. Select your next set of search criteria. To find all permits applied for in 2009 in Allegany County, select County equals Allegany. Click the Submit button.

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Appendix 27

NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

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Radiological Survey Requirements

I. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

II. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

III. Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

IV. Survey Frequency

Radiological survey data must be conducted within 6 months following the start of gas production and at intervals not to exceed 12 months thereafter.

The permit tee must conduct surveys of all equipment used on the production train prior to disposal, recycling or transfer to any entity.

Equipment that exceeds 50microrem/hr is subject licensure by the New York State Department of Health.

V. Survey data reports

Survey data must be submitted within 30 days following the survey, and must contain the information required by Section III.

NEW YORK STATE
DEPARTMENT OF HEALTH
BUREAU OF ENVIRONMENTAL RADIATION PROTECTION

Radiation Guide 1.15

GUIDE FOR APPLICATION TO POSSESS NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM) INCIDENT TO NATURAL GAS INDUSTRY

I. INTRODUCTION

PURPOSE OF GUIDE

The purpose of this regulatory guide is to provide assistance to applicants in preparing applications for new licenses for the possession of naturally occurring radioactive materials (NORM) incident to natural gas exploration and production. This regulatory guide is intended to provide you, the applicant, with information that will enable you to understand specific regulatory requirements and licensing policies as they apply to the license activities proposed.

After you are issued a license, you must conduct your program in accordance with (1) the statements, representations and procedures contained in your application; (2) the terms and conditions of the license; and (3) the Department of Health's regulations in 10 NYCRR 16 and 12 NYCRR 38. The information you provide in your application should be clear, specific and accurate.

II. FILING AN APPLICATION

You, as the applicant for a materials license, must complete Items 1 through 4 and 18 on the attached application form. For other applicable Items, submit the information on supplementary pages. Each separate sheet or document submitted with the application should be identified and keyed to the item number on the application to which it refers. All typed pages, sketches, and, if possible, drawings should be on 8 ½ x 11 inch paper to facilitate handling and review. If larger drawings are necessary, they should be folded to 8 ½ x 11inches. You should complete all items in the application in sufficient detail for the Department to determine that your equipment, facilities, training and experience, and radiation safety program are adequate to protect health and to minimize danger to life and property.

You must submit two copies of your application with attachments. Retain one copy of the application for yourself, because the license will require that you possess and use licensed material in accordance with the statements and representations in your application and in any supplements to it.

Mail your completed application and the required non-refundable triennial fee ($3000) to:

New York State Department of Health
Bureau of Environmental Radiation Protection
Flanigan Square, 547 River Street
Troy, New York 12180

Please Note: Applications received without fees will not be processed .

III. CONTENTS OF AN APPLICATION

Item 1. Name and address.

Enter the name and corporate address of the applicant and the telephone number of company management. The name of the firm must appear exactly as it appears on legal papers authorizing the conduct of business. Indicate if the name and address are different from those listed on the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill.

Item 2A. Addresses at which radioactive material will be used.

List all addresses and locations where radioactive material will be used or stored, i.e., the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill Nos., well name, and town name.

2.B. Not applicable

Item 3. Nature of business

Enter the nature of the business the applicant is engaged in and the name and telephone number (including area code) of the individual to be contacted in connection with this application.

Item 4. Previous radioactive materials license

Enter any previous or current radioactive materials license numbers and identify the issuing agency. Also indicate whether you possess any radioactive material under a general license.

Describe the circumstances of any denial, revocation or suspension of a radioactive materials license previously held.

Item 5. Department to Use Radioactive Material

Not Applicable

Item 6. Individual Users of Radioactive Materials

Not Applicable,

Item 7. Radiation Safety Officer

State the name, title and contact information (phone, fax, and e-mail) of the person designated by, and responsible to, management for the coordination of the radiation safety program. This person will be named on the license as the Radiation Safety Officer. He/she will be responsible to oversee and ensure that licensed radioactive material is possessed in accordance with regulations and the radioactive materials license.

Item 8. Radioactive Material

No response is required. The license will list Naturally Occurring Radioactive Material (NORM).

Item 9. Purpose for which Radioactive Material Will be Used

No response is required. (The type of use will be specified on the license as possession and maintenance of radiologically contaminated equipment, with specific limitations.)

Item 10. Training of individual users

Persons who perform radiological surveys that are required by regulation and radioactive materials license must receive initial and annual radiation protection training. The scope of training needs to be commensurate with their duties. Appendix A contains a model training program. Confirm that you will follow the model or submit your proposed training program for review.

Item 11. Experience with radioactive materials for individual users

No response is required. Implementation of a training program as required in Item 10 of the application addresses Item 11 for the scope of license tasks.

Item 12. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

A model procedure for conducting a radiological survey is provided in Appendix C.

Item 13. Calibration and operational checks of instrumentation

Instrument calibrations must be performed before first use of the instrument and at intervals not to exceed 12 months by an entity that is licensed by the US Nuclear Regulatory Commission or an Agreement State to perform radiological survey instrument calibrations. The instrument must be checked for proper operation (minimally a battery condition check must be performed, and a response to a radiation source is recommended) on each day of use. Records of instrument calibrations must be maintained for a period of 5 years for review by the Department. Confirm that calibrations and daily battery checks will be performed as indicated above and that instrument calibration records will be maintained.

Item 14. Personnel monitoring and bioassays

Not applicable.

Item 15. Facilities and Equipment

Submit simple sketches of any storage area(s), pipe yards, etc., for contaminated equipment.

Item 16. Radiation Protection Program

The applicant does not need to establish a comprehensive radiation safety program. However, the applicant needs to implement a radiation protection program that is commensurate with the type of radioactive material authorized by the license. Appendix B contains a model radiation protection program. Please confirm that you will implement the model program or submit your proposed program for review.

Item 17. Waste Disposal

The applicant must plan for proper disposal of radiologically contaminated equipment when their use has been discontinued. Confirm that you will dispose of radiologically contaminated items in accordance with all applicable state and federal requirements.

Item 18. Certification

Provide the signature of the chief executive officer of the corporation or legal entity applying for the license or of an individual authorized by management to sign official documents and to certify that all information in this application is accurate to the best of the signator's knowledge and belief.

IV. AMENDMENTS TO LICENSES

Licensees are required to conduct their programs in accordance with statements, representations and procedures contained in the license application and supporting documents. The license must therefore be amended if the licensee plans to make any changes in the facilities, equipment, procedures, and authorized users or radiation safety officer, or the radioactive material to be used.

Applications for license amendments may be filed either on the application form or in letter form. The application should identify the license by number and should clearly describe the exact nature of the changes, additions, or deletions. References to previously submitted information and documents should be clear and specific and should identify the pertinent information by date, page and paragraph.

APPENDIX A   Training Program for Individuals Performing Radiological Survey Measurements.

The applicant/licensee may use the services of a health physicist, licensed medical physicist or an individual who is authorized by a radioactive materials license to conduct radiological surveys. In these situations, the applicant/licensee needs to obtain documentation that the individual is qualified. Examples of documentation include a radioactive materials license that names the person as an authorized user, or copy of a resume for the health physicist or licensed medical physicist. Records of training must be maintained for a period of 5 years.

However, if the applicant/licensee plans to use his/her staff to conduct surveys, such individuals must receive training.

Individuals must demonstrate competence in the following subjects that prior to being approved to perform required surveys. Training must be conducted by an individual who is knowledgeable in health physics principles and procedures.

I. Fundamentals of Radiation Safety

- A. Characteristics of radiation
- B. Units of radiation dose and quantity of radioactivity
- C. Levels of radiation from sources of radiation
- D. Methods of minimizing radiation dose:
  1. working time
  2. working distance
  3. shielding

II. Radiation Detection Instruments

- A. Use of radiation survey instruments
  1. operational
  2. calibration
- B. Survey techniques

III. Requirements of the regulations and License Conditions

IV. Records of training will be maintained for a period of 5 years. Records will include the date of training, name of persons trained, name of the trainer and his/her employer, a copy of the training agenda or topics covered, and the results of any test or determination of proficiency. Records will be maintained for review by the Department.

APPENDIX B   Radiation Protection Program

I. Responsibility

A. The owner/licensee will delegate authority to the Radiation Safety Officer to implement the program and the responsibility to oversee the day to day oversight of the program

B. Ensure that individuals receive initial and annual radiation protection training.

C. Ensure that radiological surveys are performed in an effective manner and at the time intervals required by the License.

D. Ensure that notifications required by regulations and License Conditions are made.

E. Ensure that an inventory of radiologically contaminated equipment is maintained.

F. Ensure that contaminated equipment in storage is labeled as containing radioactive material and is not released for unrestricted use.

G. Ensure that radioactive waste is disposed in accordance with all applicable state and federal requirements.

H. Ensure that only entities that have a specific license to perform decontamination perform service of equipment that exceeds 50 microrem at any accessible surface.

II. Maintain Records of:

A. Radiation Protection Training Program

B. Results of radiological surveys including instrumentation calibrations and operational checks.

C. Inventories of contaminated equipment

D. Waste disposal records

E. Service of contaminated equipment that exceeds 50 microrem at any accessible surface, including documentation of the service provider's radioactive materials license.

F. Radiological survey data

G. Maintain a complete radioactive materials license

APPENDIX C

Radiological Survey Guidance

I. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

II Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

NEW YORK STATE DEPARTMENT OF HEALTH
RADIOACTIVE MATERIALS LICENSE

Pursuant to the Public Health Law and Part 16 of the New York State Sanitary Code, and in reliance on statements and representations heretofore made by the licensee designated below, a license is hereby issued authorizing radioactive material(s) for the purpose(s), and at the place(s) designated below. The license is subject to all applicable rules, regulations, and orders now or hereafter in effect of all appropriate regulatory agencies and to any conditions specified below.

---

1. Name

____

2. Address

____
____

Attention:
Radiation Safety Officer

3. License Number

4. a. Effective Date

____

b. Expiration Date

____

5. Reference Number
DH No. _____

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6. Radioactive Materials (element & mass no.)	7. Chemical and/or Physical Form	8. Maximum quantity licensee may possess at one time
A. Radium 226	A. Any	A. As necessary
B. Naturally Occurring Radioactive Material (NORM)	B. Any	B. As necessary

9. Authorized use. The authorized locations of use are those specified in New York State Department of Environmental Conservation Permit to Drill Nos. __________.

A. The licensee is authorized for possession only of NORM listed in License Condition No. 6 as contamination in equipment incidental to oil and gas exploration and production.

B. The licensee may perform maintenance, not inculding decontamination or removal of scale containing radioactive material on equipment that does not exceed 50 microrem per hour at any accessible point.Only a licensee authorized by the US Nuclear Regulatory Commission or an

Agreement State to perform decontamination and decommissioning services shall service equipment that exceeds 50 microrem per hour at any accessible point.

10. A. Radioactive material listed in Item 6 shall be used by, or under the supervision of the Radiation Safety Officer.

B.

C. The licensee shall notify the Department by letter within 30 days if the Radiation Safety Officer permanently discontinues performance of duties under the license.

11. Except as specifically provided otherwise by this license, the licensee shall possess and use licensed material described in Items 6, 7 and 8 of this license, in accordance with statements, representations, and procedures contained in the documents (including any enclosures) listed below:

A. Application for New York State Department of Health Radioactive Materials License dated ___________, signed by ___________.

B. Letter dated ___________, signed by _____________.

The New York State Department of Health's regulations shall govern the licensee's statements in applications or letters unless the statements are more restrictive than the regulations.

12. A. Transportation of licensed radioactive material shall be subject to all regulations of the U.S. Department of Transportation and other agencies of the United States having jurisdiction insofar as such regulations relate to the packaging of radioactive material, marking and labeling of the packages, loading and storage of packages, monitoring requirements, accident reporting, and shipping papers.

B. Transportation of low level radioactive waste shall be in accordance with the regulations of the New York State Department of Environmental Conservation as contained in 6 NYCRR Part 381.

13. The licensee shall have available appropriate survey instruments which shall be maintained operational and shall be calibrated before initial use and at subsequent intervals not exceeding twelve months by a person specifically authorized by the U.S. Nuclear Regulatory Commission or an Agreement State to perform such services. Records of all calibrations shall be kept a minimum of five years.

14, The licensee shall conduct gamma exposure rate measurements of accessable areas of gas production equipment within 6 months of the effective date of the license and at subsequent intervals not to exceed 12 months. The licensee shall maintain measurement records for review by the Department. The licensee shall notify the Department within 7 calendar days following identification of any exposure rate measurement that meet or exceed 2 millirem per hour. Notification may be made by phone or in writing.

15. Equipment in storage that exceeds 50 microrem per hour at any accessible point shall be labeled by means of paint or durable label or tag.

16. The licensee shall maintain an inventory of equipment, including but not limited to tubular goods, piping, vessels, wellheads, separators, etc., that exceeds 50 microrem per hour at any accessible point. The records of the inventories shall be maintained for inspection by the Department, and shall include the location and description of the items, and the date that items were entered on the inventory record.

17. A. Before treatment or disposal of any gas production water in a manner that could result in discharge or release to the environment, the licensee shall obtain from the New York State Department of Environmental Conservation either:

    i) A valid permit, or

    ii) A letter stating that no permit is required.

    B. The licensee shall maintain the letter or valid permit required in paragraph A of this condition on file for the duration of the license and make such letter or permit available for inspection by the Department upon request.

18. The licensee shall submit complete decontamination procedures to the Department for approval ninety (90) days prior to the termination of operations involving radioactive materials.

19. Plans of facilities which the licensee intends to dedicate to operations involving the use of radioactive material shall be submitted to the Department for review and approval prior to any such use.

20. The licensee shall maintain records of information important to safe and effective decommissioning at the location listed in License Condition No. 2 and at other locations as the licensee chooses. The records shall be maintained until this license is terminated by the Department and shall include:

    A. Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site;

    B. As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and locations of possible inaccessible contamination, such as buried pipes, which may be subject to contamination;

C. Records of the cost estimate performed for the decommissioning funding plan or the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

21. The licensee may transfer contaminated equipment that exceeds 50 microrem at any accessible point to a Department licensee if the equipment is to be used in the oil and gas industry. The licensee shall maintain records of each transfer of equipment authorized by this License Condition.

FOR THE NEW YORK STATE DEPARTMENT OF HEALTH

Date: By ____
CJB/ :
Charles J. Burns, Chief
Radioactive Materials Section
Bureau of Environmental Radiation Protection

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