Contents

Chapter 6 POTENTIAL ENVIRONMENTAL IMPACTS

All of the narrative in this Chapter incorporates by reference the entire 1992 Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program - including the draft volumes released in 1988, the final volume released in 1992 - and the 1992 Findings Statement. Therefore, the text in this Supplement is not exhaustive with respect to potential environmental impacts, but instead focuses on new, different or additional potential impacts related to horizontal drilling and high-volume hydraulic fracturing.

6.1 Water Resources

Protection of water resources is a primary emphasis of the Department and the oil and gas regulatory program. Water resources requiring attention with respect to horizontal drilling and high volume hydraulic fracturing are identified and discussed in Chapter 2.

SEQRA regulations state that "EISs should address only those potential significant adverse environmental impacts that can be reasonably anticipated and/or have been identified in the scoping process."[1]

Reasonably anticipated water resources impacts relate to water withdrawals for hydraulic fracturing; stormwater runoff; surface spills, leaks and pit or surface impoundment failures; groundwater impacts associated with well drilling and construction; waste disposal and New York City's subsurface water supply infrastructure. Except for NYC's subsurface water supply infrastructure, the same potential impacts exist statewide. The Department committed in the Final Scope to specifically evaluate potential surface water impacts if activity occurs in proximity to the Upper Delaware Scenic and Recreational River. Potential surface water impacts discussed herein are relative to all rivers in the prospective area for development, including but not limited to the Upper Delaware.

Two additional water resources concerns were frequently raised during the public scoping process. These were:

1) Potential degradation of New York City's surface drinking water supply; and

[1] 6 NYCRR 617.9(b)(2)

2) Potential groundwater contamination from the hydraulic fracturing procedure itself.

Because of the high level of public concern about both potential impacts, NYSERDA commissioned studies of their likelihood. As presented and summarized in Section 6.1 of this chapter, and in Chapters 7 and 8 and in Appendix 11, neither potential impact is reasonably anticipated.

6.1.1 Water Withdrawals

Water for hydraulic fracturing may be obtained by withdrawing it from surface water bodies away from the well site or through wells drilled into groundwater aquifers. Without proper controls on the rate, timing and location of withdrawals, stream flow modifications could result in negative impacts to a stream's best uses, including but not limited to the aquatic ecosystem, downstream riverine and riparian resources, wetlands, and aquifer supplies.

6.1.1.1 Reduced Stream Flow

Potential effects of reduced stream flow caused by withdrawals could include:

- insufficient supplies for downstream uses such as public water supply;
- adverse impacts to quantity and quality of aquatic, wetland, and terrestrial habitats and the biota that they support; and
- exacerbation of drought effects.

Seasonally, unmitigated withdrawals could adversely impact fish and wildlife health due to exposure to unsuitable water temperature and dissolved oxygen concentrations. It could also affect downstream dischargers whose effluent limits are controlled by the stream's flow rate. Water quality could be degraded and exert greater impacts on natural aquatic habitat if existing pollutants from point sources (e.g. discharge pipes) and non-point sources (e.g. runoff from farms and paved surfaces) are not sufficiently diluted or become concentrated.

6.1.1.2 Degradation of a Stream's Best Use

New York State water use classifications are provided in Section 2.4.1. All of the uses are dependent upon sufficient water in the stream to support the specified use.

6.1.1.3 Impacts to Aquatic Habitat

Habitat for stream organisms is provided by the shape of the stream channel and the water that flows through it. It is important to recognize that the physical habitat (e.g. pools, riffles instream cover, runs, glides, bank cover, etc.) essential for maintaining the aquatic ecosystem is formed by periodic disturbances that exist in the natural hydrograph; the seasonal variability in stream flow resulting from annual precipitation and associated runoff. Maintaining this habitat diversity within a stream channel is essential in providing suitable conditions for all the life stage of the aquatic organisms. Creating and maintaining high quality habitat is a function of seasonally high flows because scour of fines from pools and deposition of bedload in riffles is most predominant at high flow associated with spring snowmelt or high rain runoff. Periodic resetting of the aquatic system is an essential process for maintaining stream habitat that will continuously provide suitable habitat for all aquatic biota. Clearly, alteration of flow regimes, sediment loads and riparian vegetation will cause changes in the morphology of stream channels. Any streamflow management decision must not impair flows necessary to maintain the dynamic nature of a river channel that is in a constant state of change as substrates are scoured, moved downstream and re-deposited.

6.1.1.4 Impacts to Aquatic Ecosystems

Aquatic ecosystems could be adversely impacted by:

- changes to water quality or quantity;
- insufficient stream flow for aquatic biota or to maintain stream habitat; or
- the actual water withdrawal infrastructure.

Improperly installed water withdrawal structures can result in the entrainment of aquatic organisms, which can remove any/all life stages of fish and macroinvertebrates from their natural habitats as they are withdrawn with water. To avoid adverse impacts to aquatic biota from entrainment, intake pipes can be screened to prevent entry into the pipe. Additionally, the loss of biota that becomes trapped on intake screens, referred to as impingement, can be minimized by properly sizing the intake to reduce the flow velocity through the screens. Transporting water from the water withdrawal location for use off-site, as discussed in Section 6.6.1, can transfer invasive species from one waterbody to another via trucks, hoses, pipelines, and other equipment. Screening of the intakes can minimize this transfer; however additional site-specific mitigation considerations may be necessary.

6.1.1.5 Impacts to Downstream Wetlands

The existence and sustainability of wetland habitats directly depend on the presence of water at or near the surface of the soil. The functioning of a wetland is driven by the inflow and outflow of surface water and/or groundwater. As a result, withdrawal of surface water or groundwater for high volume hydraulic fracturing could impact wetland resources. These potential impacts depend on the amount of water within the wetland, the amount of water withdrawn from the catchment area of the wetland, and the dynamics of water flowing into and out of the wetland. Even small changes in the hydrology of the wetland can have significant impacts on the wetland plant community and on the animals that depend on the wetland. It is important to preserve the hydrologic conditions and to understand the surface water and groundwater interaction to protect wetland areas.

6.1.1.6 Aquifer Depletion

The primary concern regarding groundwater withdrawal is aquifer depletion that could affect other uses, including nearby public and private water supply wells. This includes cumulative impacts from numerous groundwater withdrawals and potential aquifer depletion from the incremental increase in withdrawals if groundwater supplies are used for hydraulic fracturing. Aquifer depletion may also result in aquifer compaction which can result in localized ground subsidence. Aquifer depletion can occur in both confined and unconfined aquifers.

The depletion of an aquifer and a corresponding decline in the groundwater level can occur when a well, or wells in an aquifer are pumped at a rate in excess of the recharge rate to the aquifer. Essentially, surface water and groundwater are one continuous resource, therefore, it also is possible that aquifer depletion can occur if an excessive volume of water is removed from a surface water body that recharges an aquifer. Such an action would result in a reduction of recharge which could potentially deplete an aquifer. This “influent” condition of surface water recharging groundwater occurs mainly in arid and semi-arid climates, and is not common in New

York, except under conditions such as induced infiltration of surface water by aquifer withdrawal (e.g., pumping of water wells).[2]

Aquifer depletion can lead to reduced discharge of groundwater to streams and lakes, reduced water availability in wetland areas, and corresponding impacts to aquatic organisms that depend on these habitats. Flowing rivers and streams are merely a surface manifestation of what is flowing through the shallow soils and rocks. Groundwater wells impact surface water flows by intercepting groundwater that otherwise would enter a stream. In fact, many New York headwater streams rely entirely on groundwater to provide flows in the hot summer months. It is therefore important to understand the hydrologic relationship between surface water, groundwater, and wetlands within a watershed to appropriately manage rates and quantities of water withdrawal.[3]

Depletion of both groundwater and surface water can occur when water withdrawals are transported out of the basin from which they originated. These transfers break the natural hydrologic cycle, since the transported water never makes it downstream nor returns to the original watershed to help recharge the aquifer. Without the natural flow regime, including seasonal high flows, stream channel and riparian habitats critical for maintaining the aquatic biota of the stream may be adversely impacted.

6.1.1.7 Cumulative Water Withdrawal Impacts[4]

There are several potential cumulative impacts from existing water use and new withdrawals associated with natural gas development, including, but not necessarily limited to:

- Stream flow and groundwater depletion,
- Loss of aquifer storage capacity,
- Water quality degradation,

---

[2] Alpha, p. 3-19

[3] Alpha, 2009.

[4] Ibid., p. 3-28

- Fish and aquatic organism impacts,
- Significant habitats, endangered, rare or threatened species impacts,
- Existing water users and reliability of their supplies,
- Underground infrastructure.

Evaluation of cumulative impacts of multiple water withdrawals must consider the existing water usage, the non-continuous nature of withdrawals and the natural replenishment of water resources. Natural replenishment is described in Section 2.4.8.

The DRBC and SRBC have developed regulations, policies, and procedures to characterize existing water use and track approved withdrawals. Changes to these systems also require Commission review. Review of the requirements of the DRBC and SRBC indicates that the operators and the reviewing authority will perform evaluations to assess the potential impacts of water withdrawal for well drilling, and consider the following issues and information.

- Comprehensive project description that includes a description of the proposed water withdrawal (location, volume, and rate) and its intended use;
- Existing water use in the withdrawal area;
- Potential impacts, both ecological and to existing users, from the new withdrawal;
- Availability of water resources (surface water and/or groundwater) to support the proposed withdrawals;
- Availability of other water sources (e.g., treated waste water) and conservation plans to meet some or all of the water demand;
- Contingencies for low flow conditions that include passby flow criteria;
- Public notification requirements;
- Monitoring and reporting;
- Inspections;
- Mitigation measures;
- Supplemental investigations, including but not limited to, aquatic surveys;

- Potential impact to significant habitat and endangered rare or threatened species;
- Protection of subsurface infrastructure.

Existing Water Usage and Withdrawals

The DRBC and SRBC currently each use a permit system and approval process to regulate existing water usage in their respective basins. The DRBC and SRBC require applications in which operators provide a comprehensive project description that includes the description of the proposed withdrawals. The project information required includes site location, water source(s), withdrawal location(s), proposed timing and rate of water withdrawal and the anticipated project duration. The operators identify the amount of consumptive use (water not returned to the basin) and any import or export of water to or from the basin. The method of conveyance from the point(s) of withdrawal to the point(s) of use also is defined.

There are monitoring and reporting requirements once the withdrawal and consumptive use for a project has been approved. These requirements include metering withdrawals and consumptive use, and submitting quarterly reports to the Commission. Monitoring requirements can include stream flow and stage measurements for surface water withdrawals and monitoring groundwater levels for groundwater withdrawals.

Surface water and groundwater are withdrawn daily for a wide range of uses. New York ranks as one of the top states with respect to the total amount of water withdrawals. Figure 6.1 presents a graph indicating the total water withdrawal for New York is approximately 9,000 to 10,000 million gallons per day (MGD) (9 to 10 billion gallons per day), based on data from 2000.

A graph showing the maximum approved daily consumptive use of water reported by the SRBC is shown in Figure 6.2. The largest consumptive identified use is for water supply at approximately 325 million gallons per day (MGD), followed by power generation at 150 MGD, and recreation at 50 MGD.

The DRBC reports on the withdrawal of water for various purposes. The daily water withdrawals, exports, and consumptive uses in the Delaware River Basin are shown in Figure 6.3. The total water withdrawal from the Delaware River Basin was 8,736 MGD, based on 2003 water use records. The highest water use was for thermoelectric power generation at 5,682 MGD (65%), followed by 875 MGD(10%) for public water supply, 650 MGD (7.4%) for New York City, 617 MGD (7 %) for hydroelectric, and 501 MGD (5.7%) for industrial purposes. The amount of water used for mining is 70 MGD (0.8%). The "mining" category typically includes withdrawals for oil and gas drilling; however, DRBC has not yet approved water withdrawal for Marcellus shale drilling operations. The information in Figure 6.3 shows that 4.3 percent (14 MGD) of the water withdrawn for consumptive use is for mining and 88 percent (650 MGD) of water exported from the Delaware River Basin is diverted to New York City.

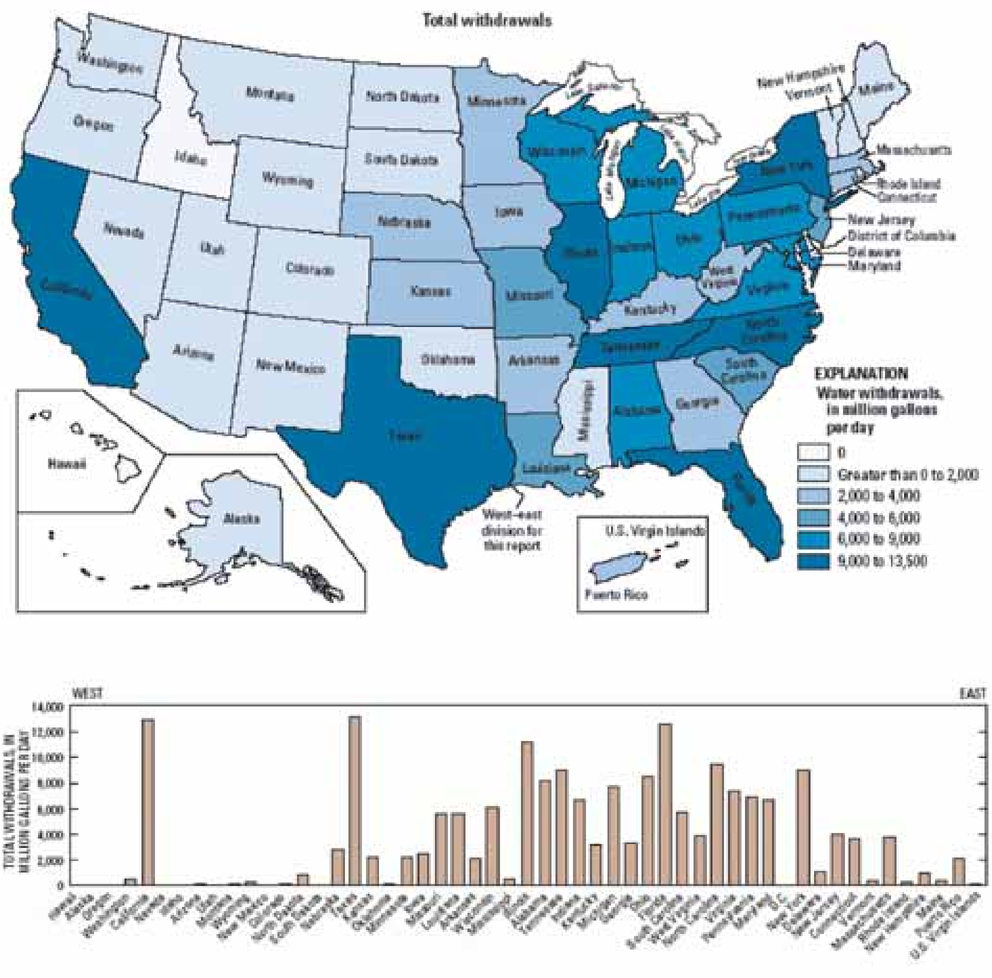
Whereas certain withdrawals, like many public water supplies are returned to the basin's hydrologic cycle, out-of-basin transfers, like the NYC water-supply diversion, some evaporative losses, and withdrawals for hydraulic fracturing, are considered as 100 percent consumptive losses because this water is essentially lost to the basin's hydrologic cycle.

Withdrawals for High-Volume Hydraulic Fracturing

The total volume of water to be withdrawn for horizontal well drilling and associated high volume hydraulic fracturing will not be known until applications are received and reviewed, and approved or rejected by the appropriate regulatory agency or agencies. The DRBC has received an application (Docket No. D-2009-20-1) to withdraw up to 1.0 MGD of surface water from the West Branch Delaware River to support natural gas development and extraction activities in the Delaware River Basin. The SRBC approved gas drilling and hydraulic fracturing-related surface water withdrawals up to approximately 8.86 MGD from 18 separate locations and 9.24 MGD from 19 separate locations in Pennsylvania at the March 24 and June 18, 2009 Commission meetings (SRBC, 2009). The approved volumes of the individual applications in 2009 are typical of previous withdrawals approved by the commission and range from 0.041 MGD to 3.0 MGD.

Comparison of the water withdrawal statistics with typical withdrawal volumes for natural gas drilling indicates that the historical percentage of water withdrawal for natural gas drilling is very low. The percentage of water withdrawal specifically for horizontal well drilling and high volume hydraulic fracturing also is expected to be relatively low, compared with existing everyday consumptive water losses. Figure 6.2 shows that the "current estimate" of water use for gas drilling is approximately 30 MGD in the Susquehanna River Basin, or less than 6 percent of the total use for water supply, power, and recreation.

Figure 6.1 – Water Withdrawals in the United States



Source: USGS

FIGURE 3-2

WATER WITHDRAWALS IN THE UNITED STATES

ALPHA GEOSCIENCE
Alpha Project No. 09104

Technical Support Document to the Draft Supplemental Generic Environmental Impact Statement

Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-2-NY_Water_Usage.cvx)

Figure 6.2 - Maximum Approved Daily Consumptive Use in the Susquehanna River Basin

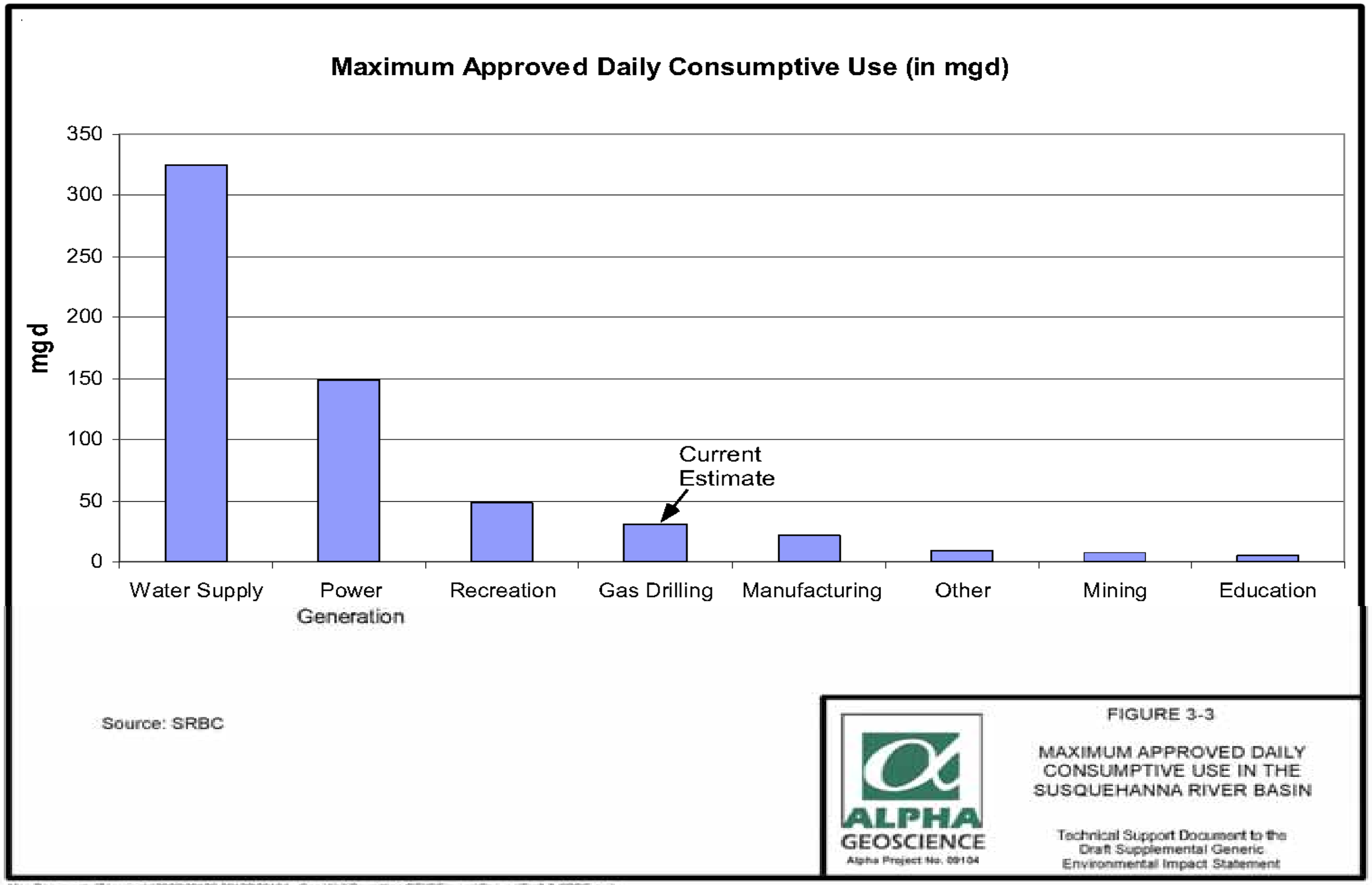
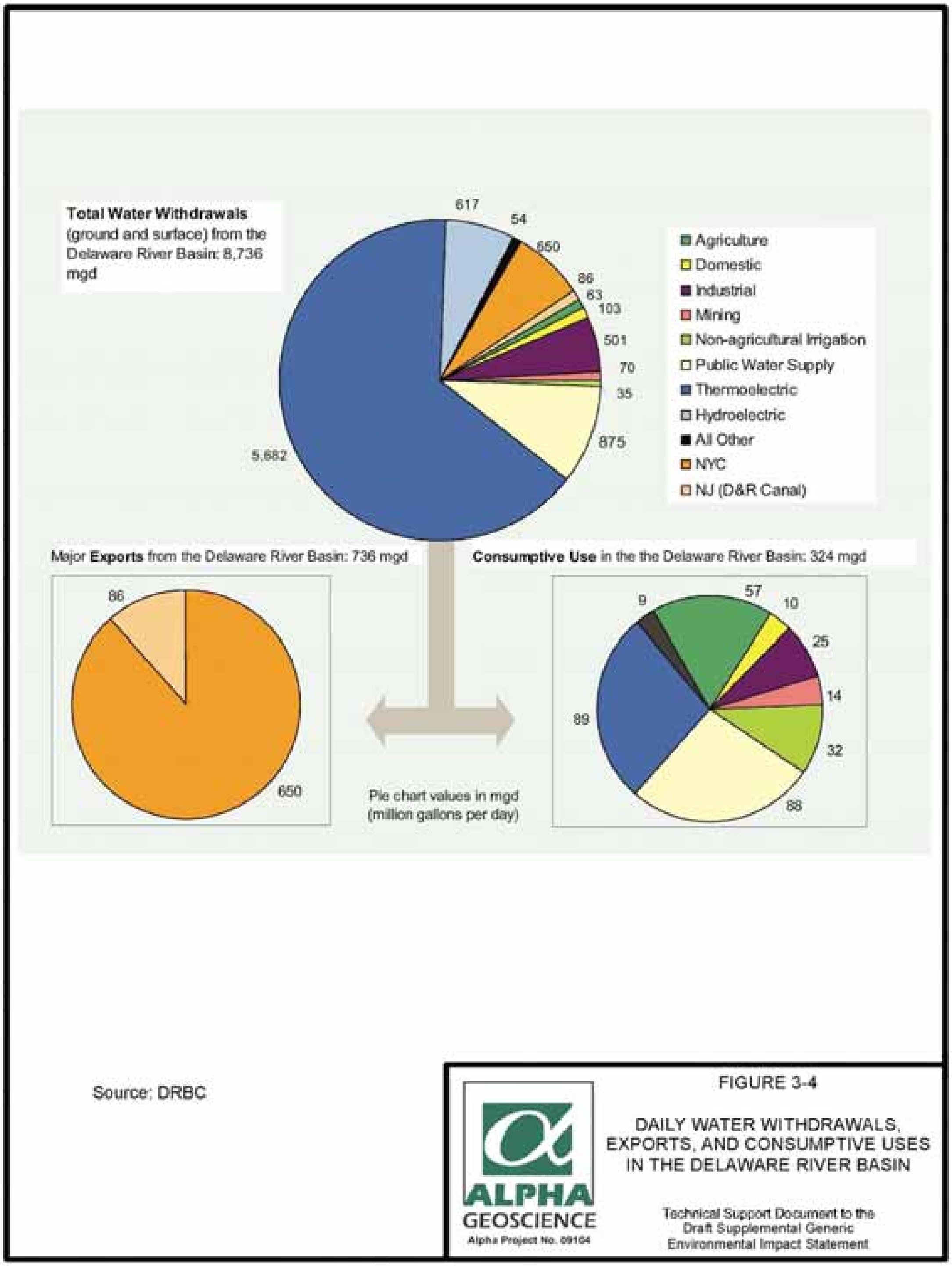


Figure 6.3 - Daily Water Withdrawals, Exports, and Consumptive Uses in the Delaware River Basin



Map Document: (Z:\projects\2009\09100-09120\09104 - Gas Well Permitting GEIS\Figures\Canvas\Fig3-3-DRBC.cvx)

6.1.2 Stormwater Runoff

Stormwater runoff, whether as a result of rain fall or snow melt, is a valuable resource. It is the source water for lakes and streams, as well as groundwater aquifers. However, stormwater runoff is also a pathway for contaminants to be conveyed from the land surface to streams and lakes and groundwater. This is especially true for asphalt, concrete, gravel/dirt roads and other impervious surfaces, where any material collected on the ground is then washed away to a nearby surface water body, or from intensive outdoor construction and industrial activity where materials and products are exposed to rainfall. In severe cases, stormwater runoff may also cause flooding problems.

On an undisturbed landscape, runoff is retarded by vegetation and top soil, allowing it to slowly filter into the ground. This benefits water resources by using natural filtering properties, replenishing groundwater aquifers and feeding lakes and streams during dry periods. On a disturbed or developed landscape, it is common for the ground surface to be compacted or otherwise made less pervious and for runoff to be shunted away more quickly. Such hydrological modifications result in less groundwater recharge and more rapid runoff to streams, which may cause increased stream erosion and result in water quality degradation, habitat loss and flood damage.

All phases of natural gas well development, from initial land clearing for access roads, equipment staging areas and well pads, to drilling and fracturing operations, production and final reclamation, have the potential to cause water resource impacts during rain and snow melt events if stormwater is not properly managed.

Initial land clearing exposes soil to erosion and more rapid runoff. Construction equipment is a potential source of contamination from such things as hydraulic, fuel and lubricating fluids. Equipment and any materials that are spilled, including additive chemicals and fuel, are exposed to rainfall, so that contaminants may be conveyed off-site during rain events if they are not properly contained. Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pit is proposed.

A production site, including access roads, is also a potential source of stormwater runoff impacts because its hydrological characteristics may be substantially different from the pre-developed condition. There is a greater potential for stormwater impacts from a larger well pad during the production phase, compared with a smaller well pad for a single vertical well.

6.1.3 Surface Spills and Releases at the Well Pad

Spills or releases can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, accidents (including vehicle collisions), ground fires, or improper operations. Spilled, leaked or released fluids could flow to a surface water body or infiltrate the ground, reaching subsurface soils and aquifers.

6.1.3.1 Drilling

Contamination of surface water bodies and groundwater resources during well drilling could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor casing construction, or accidental spills and releases. Surface spills would involve materials and fluids present at the site during the drilling phase. Pit leakage or failure could also involve well fluids. These issues are discussed in Chapters 8 and 9 of the GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. GEIS conclusions regarding pit construction standards and liner specifications were largely based upon the short duration of a pit's use. The greater intensity and duration of surface activities associated with well pads with multiple wells increases the odds of an accidental spill, pit leak or pit failure if mitigation measures are not sufficiently durable. Concerns are heightened if on-site pits for handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad.

6.1.3.2 Hydraulic Fracturing Additives

As with the drilling phase, contamination of surface water bodies and groundwater resources during well stimulation could occur as a result of failure to maintain stormwater controls, ineffective site management and surface and subsurface fluid containment practices, poor well construction and grouting, or accidental spills and releases. These issues are discussed in Chapters 8 and 9 of the GEIS, but are acknowledged again here because of the larger volumes of fluids and materials to be managed for high-volume hydraulic fracturing. The potential contaminants are listed in Table 5.6 and grouped into categories determined by NYSDOH in Table 5.7. URS compared the list of additive chemicals to the parameters regulated via primary or secondary drinking water standards, SPDES discharge limits (see Section 7.1.8), and Division of Water Technical and Operational Guidance Series 1.1.1 (TOGS111), *Ambient Water Quality Standards and Guidance Values and Groundwater Effluent Limitations.*[5,6] See Table 6.1.

6.1.3.3 Flowback Water

Gelling agents, surfactants and chlorides are identified in the GEIS as the flowback water components of greatest environmental concern.[7] Other flow back components can include other dissolved solids, metals, biocides, lubricants, organics and radionuclides. Opportunities for spills, leaks, operational errors, and pit or surface impoundment failures during the flowback water recovery stage are the same as they are during the prior stages with the additional potential of releases from:

- hoses or pipes used to convey flowback water to tanks, an on-site pit, a centralized surface impoundment, or a tanker truck for transportation to a treatment or disposal site; and
- tank leakage or failure of a pit or surface impoundment to effectively contain fluid.

Flowback water composition based on a limited number of out-of-state samples from Marcellus wells is presented in Table 5.9. A summary by chemical category prepared by NYSDOH is presented in Section 5.11.3.2. A comparison of detected flowback parameters, except radionuclides, to regulated parameters is presented in Table 6.1[8]

Table 6.2 lists parameters found in the flowback analyses, except radionuclides, that are regulated in New York. The number of samples that were analyzed for the particular parameter is shown in Column 3, and the number of samples in which parameters were detected is shown in

---

5 URS, p. 4-18, et seq.

6 Hhttp://www.dec.ny.gov/regulations/2652.htmlH

7 GEIS, p. 9-37

8 URS, p. 4-18, et seq.

Column 4. The minimum, median and maximum concentrations detected are indicated in Columns 5, 6 and 7.[9]

Radionuclides data is presented in Chapter 5, and potential impacts and regulation are discussed in Section 6.8.

Table 6.3 lists parameters found in the flowback analyses that are not regulated in New York. Column 2 is the number of samples that analyzed for the particular parameter; column 3 is the number in which the parameter was detected.[10]

Information presented in Tables 6.2 and 6.3 are based on limited data from Pennsylvania and West Virginia. Samples were not collected specifically for this type of analysis or under DEC's oversight. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. The raw data for these tables came from several sources, with likely varying degrees of reliability, and the analytical methods used were not all the same for given parameters. Sometimes, laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days after the well is fractured. This data does not control for any of these variables.[11]

[9] URS, pp. 4-10, 4-31 et seq.

[10] URS, pp. 4-10, p. 4-35

[11] URS, p. 4-31

Table 6.1 – Comparison of additives used or proposed for use in NY, parameters detected in analytical results of flowback from the Marcellus operations in PA and WV, and parameters regulated via primary and secondary drinking water standards, SPDES or TOGS111

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	1,1,1-Trifluorotoluene		Yes				
02634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one	Yes					
00095-63-6	1,2,4 trimethylbenzene	Yes				Table 9	Tables 1,5
00123-91-1	1,4 Dioxane	Yes				Table 8	
	1,4-Dichlorobutane		Yes			Table 10	
03452-07-1	1-eicosene	Yes					
00629-73-2	1-hexadecene	Yes					
00112-88-9	1-octadecene	Yes					
01120-36-1	1-tetradecene	Yes					
10222-01-2	2,2 Dibromo-3-nitrilopropionamide	Yes				Table 9	Tables 1,5
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	Yes					
73003-80-2	2,2-Dobromomalonamide	Yes					
	2,4,6-Tribromophenol		Yes			Table 6	Tables 1,5
	2,5-Dibromotoluene		Yes				
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer	Yes					
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride	Yes					
00052-51-7	2-Bromo-2-nitro-1,3-propanediol	Yes				Table 10	
00111-76-2	2-Butoxy ethanol	Yes					

12 As with Table 5.6, information in the "Used in Additives" column is based on the composition of additives used or proposed for use in New York.

13 As with Table 5.8, information in the "Found in Flowback" column is based on analytical results of flowback from operations in Pennsylvania or West Virginia. There are/may be products used in fracturing operations in Pennsylvania that have not yet been proposed for use in New York for which, therefore, the NYSDEC does not have chemical composition data.

14 Limits marked with a pound sign (#) are based on secondary drinking water standards.

15 SPDES or TOGS typically regulates or provides guidance for the total substance, e.g. iron; and rarely regulates or provides guidance for only its dissolved portion, e.g. dissolved iron. The dissolved component is implicitly covered in the total substance. Therefore, the dissolved component is not included in Table 4-4. Flowback analyses provided information for the total and dissolved components of metals, which are listed in Table 3-1. Understanding the dissolved vs. suspended portions of a substance is valuable when determining potential treatment techniques.

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
01113-55-9	2-Dibromo-3-Nitriloprionamide (2-Monobromo-3-nitriilopropionamide)	Yes					
00104-76-7	2-Ethyl Hexanol	Yes					
	2-Fluorobiphenyl		Yes			Table 6	Tables 1,5
	2-Fluorophenol		Yes			Table 6	Tables 1,5
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol	Yes				Table 10	
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer	Yes					
09003-03-6	2-propenoic acid, homopolymer, ammonium salt	Yes					
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate	Yes					
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)	Yes					
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite	Yes					
00107-19-7	2-Propyn-1-ol / Progargyl Alcohol	Yes					
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,	Yes					
00115-19-5	3-methyl-1-butyn-3-ol	Yes					
00056-57-5	4-Nitroquinoline-1 -oxide		Yes			Table 8	
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol	Yes					
	4-Terphenyl-d14		Yes			Table 6	Tables 1,5
00064-19-7	Acetic acid	Yes				Table 10	
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine	Yes					
00108-24-7	Acetic Anhydride	Yes				Table 10	
00067-64-1	Acetone	Yes	Yes			Table 7	Tables 1,5
00079-06-1	Acrylamide	Yes		0	TT	Table 9	Tables 1,5
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	Yes					
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide	Yes					
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					
15085-02-3	Acrylamide-sodium acrylate copolymer	Yes					
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)	Yes					
	Aliphatic acids	Yes					
	Aliphatic alcohol glycol ether	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent	Yes					
	Alkalinity, Carbonate, as CaCO3		Yes			Table 10	
64743-02-8	Alkenes	Yes					
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt	Yes					
	Alkyl Aryl Polyethoxy Ethanol	Yes					
	Alkylaryl Sulfonate	Yes					
09016-45-9	Alkylphenol ethoxylate surfactants	Yes		0.5 mg/L[#]			
07439-90-5	Aluminum		Yes	0.05 to 0.2 mg/L[#]		Table 7	Tables 1,5
01327-41-9	Aluminum chloride	Yes					
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated	Yes					
71011-04-6	Amines, Ditallow alkyl, ethoxylated	Yes					
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates	Yes					
01336-21-6	Ammonia	Yes				Yes	
00631-61-8	Ammonium acetate	Yes				Table 10	
68037-05-8	Ammonium Alcohol Ether Sulfate	Yes					
07783-20-2	Ammonium bisulfate	Yes					
10192-30-0	Ammonium Bisulphite	Yes					
12125-02-9	Ammonium Chloride	Yes				Table 10	
07632-50-0	Ammonium citrate	Yes					
37475-88-0	Ammonium Cumene Sulfonate	Yes					
01341-49-7	Ammonium hydrogen-difluoride	Yes					
06484-52-2	Ammonium nitrate	Yes					
07727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate	Yes					
01762-95-4	Ammonium Thiocyanate	Yes				Table 10	
07440-36-0	Antimony		Yes	0.006	0.006	Table 6	Tables 1,5
07664-41-7	Aqueous ammonia	Yes	Yes			Table 7	Tables 1,5
	Aromatic hydrocarbons	Yes					
	Aromatic ketones	Yes					
07440-38-2	Arsenic		Yes	0	0.01	Table 6	Tables 1,5
07440-39-3	Barium		Yes	2	2	Table 7	Tables 1,5
	Barium Strontium P.S. (mg/L)		Yes				

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay	Yes					
00071-43-2	Benzene	Yes	Yes	0	0.005	Table 6	Tables 1,5
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	Yes					
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	Yes					
	Bicarbonates (mg/L)		Yes			Table 10	
	Biochemical Oxygen Demand		Yes			Yes	
00117-81-7	Bis(2-ethylhexyl)phthalate		Yes	0	0.006	Table 6	Tables 1,5
10043-35-3	Boric acid	Yes					
01303-86-2	Boric oxide / Boric Anhydride	Yes					
07440-42-8	Boron		Yes			Table 7	Tables 1,5
24959-67-9	Bromide		Yes			Table 7	Tables 1,5
00075-25-2	Bromoform		Yes			Table 6	Tables 1,5
00071-36-3	Butan-1-ol	Yes				Table 10	Tables 1,5
68002-97-1	C10 - C16 Ethoxylated Alcohol	Yes					
68131-39-5	C12-15 Alcohol, Ethoxylated	Yes					
07440-43-9	Cadmium		Yes	0.005	0.005	Table 6	Tables 1,5
07440-70-2	Calcium		Yes			Table 8	
10043-52-4	Calcium chloride	Yes					
00124-38-9	Carbon Dioxide	Yes					
68130-15-4	Carboxymethylhydroxypropyl guar	Yes					
09012-54-8	Cellulase / Hemicellulase Enzyme	Yes					
09004-34-6	Cellulose	Yes					
	Chemical Oxygen Demand		Yes			Yes	
	Chloride		Yes	250 mg/L#		Table 7	Tables 1,5
10049-04-4	Chlorine Dioxide	Yes		MRDLG=0.8	MRDL=0.8	Table 10	
00124-48-1	Chlorodibromomethane		Yes			Table 6	Tables 1,5
07440-47-3	Chromium		Yes	0.1	0.1	Table 6	Tables 1,5
00077-92-9	Citric Acid	Yes					
94266-47-4	Citrus Terpenes	Yes					
07440-48-4	Cobalt		Yes			Table 7	Table 1
61789-40-0	Cocamidopropyl Betaine	Yes					
68155-09-9	Cocamidopropylamine Oxide	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
68424-94-2	Coco-betaine	Yes					
	Color		Yes	15 (Color Units)#		Table 7	
07440-50-8	Copper		Yes	1.0#	TT; Action Level=1.3	Table 6	Tables 1,5
07758-98-7	Copper (II) Sulfate	Yes					
31726-34-8	Crissanol A-55	Yes					
14808-60-7	Crystalline Silica (Quartz)	Yes					
07447-39-4	Cupric chloride dihydrate	Yes					
00057-12-5	Cyanide		Yes	0.2	0.2	Table 6	Tables 1,5
01120-24-7	Decyldimethyl Amine	Yes					
02605-79-0	Decyl-dimethyl Amine Oxide	Yes					
03252-43-5	Dibromoacetonitrile	Yes				Table 9	Tables 1
00075-27-4	Dichlorobromomethane		Yes			Table 6	Tables 1,5
25340-17-4	Diethylbenzene	Yes					
00111-46-6	Diethylene Glycol	Yes				Table 10	
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt	Yes					
28757-00-8	Diisopropyl naphthalenesulfonic acid	Yes					
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt	Yes					
07398-69-8	Dimethyldiallylammonium chloride	Yes					
25265-71-8	Dipropylene glycol	Yes					
00139-33-3	Disodium Ethylene Diamine Tetra Acetate	Yes					
05989-27-5	D-Limonene	Yes					
00123-01-3	Dodecylbenzene	Yes					
27176-87-0	Dodecylbenzene sulfonic acid	Yes					
42504-46-1	Dodecylbenzenesulfonate isopropanolamine	Yes					
00050-70-4	D-Sorbitol / Sorbitol	Yes					
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase	Yes					
149879-98-1	Erucic Amidopropyl Dimethyl Betaine	Yes					
00089-65-6	Erythorbic acid, anhydrous	Yes					
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	Yes					
00107-21-1	Ethane-1,2-diol / Ethylene Glycol	Yes				Table 7	Tables 1,5

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
09002-93-1	Ethoxylated 4-tert-octylphenol	Yes					
68439-50-9	Ethoxylated alcohol	Yes					
126950-60-5	Ethoxylated alcohol	Yes					
68951-67-7	Ethoxylated alcohol (C14-15)	Yes					
68439-46-3	Ethoxylated alcohol (C9-11)	Yes					
66455-15-0	Ethoxylated Alcohols	Yes					
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)	Yes					
68439-51-0	Ethoxylated Alcohols (C12-14)	Yes					
78330-21-9	Ethoxylated branch alcohol	Yes					
34398-01-1	Ethoxylated C11 alcohol	Yes					
61791-12-6	Ethoxylated Castor Oil	Yes					
61791-29-5	Ethoxylated fatty acid, coco	Yes					
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine	Yes					
68439-45-2	Ethoxylated hexanol	Yes					
09036-19-5	Ethoxylated octylphenol	Yes					
09005-67-8	Ethoxylated Sorbitan Monostearate	Yes					
09004-70-3	Ethoxylated Sorbitan Trioleate	Yes					
00064-17-5	Ethyl alcohol / ethanol	Yes					
00100-41-4	Ethyl Benzene	Yes	Yes	0.7	0.7	Table 6	Tables 1,5
00097-64-3	Ethyl Lactate	Yes					
09003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)	Yes					
00075-21-8	Ethylene oxide	Yes				Table 9	Tables 1,5
05877-42-9	Ethyloctynol	Yes					
68526-86-3	Exxal 13	Yes					
61790-12-3	Fatty Acids	Yes					
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	Yes					
09043-30-5	Fatty alcohol polyglycol ether surfactant	Yes		0.5 mg/L[#]			
07705-08-0	Ferric chloride	Yes				Table 10	
07782-63-0	Ferrous sulfate, heptahydrate	Yes					
16984-48-8	Fluoride		Yes	2[#]	4	Table 7	Tables 1,5
00050-00-0	Formaldehyde	Yes				Table 8	Tables 1,5

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	Yes					
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	Yes					
00075-12-7	Formamide	Yes					
00064-18-6	Formic acid	Yes				Table 10	
00110-17-8	Fumaric acid	Yes				Table 10	
65997-17-3	Glassy calcium magnesium phosphate	Yes					
00111-30-8	Glutaraldehyde	Yes					
00056-81-5	Glycerol / glycerine	Yes					
09000-30-0	Guar Gum	Yes					
64742-94-5	Heavy aromatic petroleum naphtha	Yes					
09025-56-3	Hemicellulase	Yes					
07647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid	Yes					
07722-84-1	Hydrogen Peroxide	Yes				Table 10	
00079-14-1	Hydroxy acetic acid	Yes					
35249-89-9	Hydroxyacetic acid ammonium salt	Yes					
09004-62-0	Hydroxyethyl cellulose	Yes					
05470-11-1	Hydroxylamine hydrochloride	Yes					
39421-75-5	Hydroxypropyl guar	Yes					
07439-89-6	Iron		Yes	0.3 mg/L[#]		Table 7	Tables 1,5
35674-56-7	Isomeric Aromatic Ammonium Salt	Yes					
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic	Yes					
00064-63-0	Isopropanol	Yes				Table 10	
00098-82-8	Isopropylbenzene (cumene)	Yes				Table 9	Tables 1,5
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline	Yes					
08008-20-6	Kerosene	Yes					
64742-81-0	Kerosine, hydrodesulfurized	Yes					
00063-42-3	Lactose	Yes					
07439-92-1	Lead		Yes	0	TT; Action Level 0.015	Table 6	Tables 1,5
64742-95-6	Light aromatic solvent naphtha	Yes					
01120-21-4	Light Paraffin Oil	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	Lithium		Yes			Table 10	
07439-95-4	Magnesium		Yes			Table 7	Tables 1,5
14807-96-6	Magnesium Silicate Hydrate (Talc)	Yes					
07439-96-5	Manganese		Yes	0.05 mg/L[#]		Table 7	Tables 1,5
01184-78-7	Methanamine, N,N-dimethyl-, N-oxide	Yes					
00067-56-1	Methanol	Yes				Table 10	
00074-83-9	Methyl Bromide		Yes			Table 6	Tables 1,5
00074-87-3	Methyl Chloride		Yes	0	0.005	Table 6	Tables 1,5
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	Yes					
08052-41-3	Mineral spirits / Stoddard Solvent	Yes					
07439-98-7	Molybdenum		Yes			Table 7	
00141-43-5	Monoethanolamine	Yes					
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride	Yes					
64742-48-9	Naphtha (petroleum), hydrotreated heavy	Yes					
00091-20-3	Naphthalene	Yes	Yes			Table 6	Tables 1,5
38640-62-9	Naphthalene bis(1-methylethyl)	Yes					
00093-18-5	Naphthalene, 2-ethoxy-	Yes					
68909-18-2	N-benzyl-alkyl-pyridinium chloride	Yes					
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	Yes					
07440-02-0	Nickel		Yes			Table 6	Tables 1,5
	Nitrobenzene-d5		Yes				
07727-37-9	Nitrogen, Liquid form	Yes					
	Nitrogen, Total as N		Yes				Table 5
68412-54-4	Nonylphenol Polyethoxylate	Yes					
	Oil and Grease		Yes				Table 5
121888-66-2	Organophilic Clays	Yes					
	O-Terphenyl		Yes			Table 6	Tables 1,5
	Oxyalkylated alkylphenol	Yes					
64742-65-0	Petroleum Base Oil	Yes					
	Petroleum distillate blend	Yes					
	Petroleum hydrocarbons		Yes				

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
64741-68-0	Petroleum naphtha	Yes					
	pH		Yes	6.5-8.5[#]			Table 5
00108-95-2	Phenol		Yes			Table 6	Tables 1,5
	Phenol-d5		Yes				
	Phenols		Yes			Table 6	Tables 1,5
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt	Yes					
57723-14-0	Phosphorus		Yes			Table 7	Table 1
08000-41-7	Pine Oil	Yes					
24938-91-8	Poly(oxy-1,2-ethanediyl), ?-tridecyl-?-hydroxy-	Yes					
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-	Yes					
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol	Yes					
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized	Yes					
56449-46-8	polyethlene glycol oleate ester	Yes					
	Polyethoxylated alkanol	Yes					
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate	Yes					
	Polymeric Hydrocarbons	Yes					
09005-65-6	Polyoxyethylene Sorbitan Monooleate	Yes					
61791-26-2	Polyoxylated fatty amine salt	Yes					
07440-09-7	Potassium		Yes			Table 8	
00127-08-2	Potassium acetate	Yes					
12712-38-8	Potassium borate	Yes					
00584-08-7	Potassium carbonate	Yes					
07447-40-7	Potassium chloride	Yes					
00590-29-4	Potassium formate	Yes					
01310-58-3	Potassium Hydroxide	Yes				Table 10	
13709-94-9	Potassium metaborate	Yes					
24634-61-5	Potassium Sorbate	Yes					
112926-00-8	Precipitated silica / silica gel	Yes					
00057-55-6	Propane-1,2-diol, or Propylene glycol	Yes					Tables 1,5
00107-98-2	Propylene glycol monomethyl ether	Yes				Table 10	
68953-58-2	Quaternary Ammonium Compounds	Yes				Table 9	Tables 1

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
62763-89-7	Quinoline,2-methyl-, hydrochloride	Yes					
15619-48-4	Quinolinium, 1-(phenylmethl),chloride	Yes					
	Salt of amine-carbonyl condensate	Yes					
	Salt of fatty acid/polyamine reaction product	Yes					
	Scale Inhibitor (mg/L)		Yes				
07782-49-2	Selenium		Yes	0.05	0.05	Table 6	Tables 1,5
07631-86-9	Silica, Dissolved	Yes				Table 8	
07440-22-4	Silver		Yes	0.10 mg/L[#]		Table 6	Tables 1,5
07440-23-5	Sodium		Yes			Table 7	Tables 1,5
05324-84-5	Sodium 1-octanesulfonate	Yes					
00127-09-3	Sodium acetate	Yes					
95371-16-7	Sodium Alpha-olefin Sulfonate	Yes					
00532-32-1	Sodium Benzoate	Yes					
00144-55-8	Sodium bicarbonate	Yes					
07631-90-5	Sodium bisulfate	Yes					
07647-15-6	Sodium Bromide	Yes					
00497-19-8	Sodium carbonate	Yes					
07647-14-5	Sodium Chloride	Yes					
07758-19-2	Sodium chlorite	Yes					
03926-62-3	Sodium Chloroacetate	Yes					
00068-04-2	Sodium citrate	Yes					
06381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt	Yes					
02836-32-0	Sodium Glycolate	Yes					
01310-73-2	Sodium Hydroxide	Yes				Table 10	
07681-52-9	Sodium hypochlorite	Yes				Table 10	
07775-19-1	Sodium Metaborate .8H2O	Yes					
10486-00-7	Sodium perborate tetrahydrate	Yes					
07775-27-1	Sodium persulphate	Yes					
09003-04-7	Sodium polyacrylate	Yes					
07757-82-6	Sodium sulfate	Yes				Table 10	
01303-96-4	Sodium tetraborate decahydrate	Yes					
07772-98-7	Sodium Thiosulfate	Yes					
01338-43-8	Sorbitan Monooleate	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
	Specific Conductivity		Yes				
07440-24-6	Strontium		Yes			Table 9	Table 1
00057-50-1	Sucrose	Yes					
	Sugar	Yes					
05329-14-6	Sulfamic acid	Yes					
14808-79-8	Sulfate		Yes	250 mg/L#		Table 7	Tables 1,5
	Sulfide		Yes			Table 7	Tables 1,5
14265-45-3	Sulfite		Yes			Table 7	Table 1
	Surfactant blend	Yes		0.5 mg/L#			
	Surfactants MBAS		Yes	0.5 mg/L#			
112945-52-5	Syntthetic Amorphous / Pyrogenic Silica / Amorphous Silica	Yes					
68155-20-4	Tall Oil Fatty Acid Diethanolamine	Yes					
08052-48-0	Tallow fatty acids sodium salt	Yes					
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized	Yes					
68647-72-3	Terpene and terpenoids	Yes					
68956-56-9	Terpene hydrocarbon byproducts	Yes					
00127-18-4	Tetrachloroethylene		Yes	0	0.005	Table 6	Tables 1,5
00533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)	Yes					
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)	Yes					
00075-57-0	Tetramethyl ammonium chloride	Yes					
00064-02-8	Tetrasodium Ethylenediaminetetraacetate	Yes					
07440-28-0	Thallium		Yes	0.0005	0.002	Table 6	Tables 1,5
00068-11-1	Thioglycolic acid	Yes					
00062-56-6	Thiourea	Yes				Table 10	
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone	Yes					
07440-32-6	Titanium		Yes			Table 7	
00108-88-3	Toluene	Yes	Yes	1	1	Table 6	Tables 1,5
	Total Dissolved Solids		Yes	500 mg/L#			Table 5
	Total Kjeldahl Nitrogen		Yes			Yes	
	Total Organic Carbon		Yes			Yes	
	Total Suspended Solids		Yes			Yes	
81741-28-8	Tributyl tetradecyl phosphonium chloride	Yes					
68299-02-5	Triethanolamine hydroxyacetate	Yes					

CAS Number	Parameter Name	Used in Additives[12]	Found in Flowback[13]	MCLG (mg/L)[14]	MCL or TT (mg/L)	SPDES Tables[15]	TOGS111
00112-27-6	Triethylene Glycol	Yes					
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated	Yes					
00150-38-9	Trisodium Ethylenediaminetetraacetate	Yes					
05064-31-3	Trisodium Nitrilotriacetate	Yes					
07601-54-9	Trisodium ortho phosphate	Yes					
00057-13-6	Urea	Yes					
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer	Yes					
	Xylenes		Yes	10	10		Tables 1,5
07440-66-6	Zinc		Yes	5 mg/L#		Table 6	Tables 1,5
	Zirconium		Yes				

Table 6.2– Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[16]

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	1,4-Dichlorobutane	1	1	198	198	198	%REC
	2,4,6-Tribromophenol[17]	1	1	101	101	101	%REC
	2-Fluorobiphenyl[18]	1	1	71	71	71	%REC
	2-Fluorophenol[19]	1	1	72.3	72.3	72.3	%REC
00056-57-5	4-Nitroquinoline-1 -oxide	24	24	1422	13908	48336	mg/L
	4-Terphenyl-d14 [20]	1	1	44.8	44.8	44.8	%REC
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Alkalinity, Carbonate, as CaCO3	31	9	4.9	91	117	mg/L
07439-90-5	Aluminum	29	3	0.08	0.09	1.2	mg/L
07440-36-0	Antimony	29	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	28	25	12.4	58.1	382	mg/L
07440-38-2	Arsenic	29	2	0.09	0.1065	0.123	mg/L
07440-39-3	Barium	34	34	0.553	661.5	15700	mg/L
00071-43-2	Benzene	29	14	15.7	479.5	1950	µg/L
	Bicarbonates [21]	24	24	0	564.5	1708	mg/L
	Biochemical Oxygen Demand	29	28	3	274.5	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	23	2	10.3	15.9	21.5	µg/L

[16] Information presented in Table 6.1 and Table 6.3 are based on limited data from Pennsylvania and West Virginia. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. In addition, the raw data for these tables came from several sources, with likely varying degrees of reliability. Also, the analytical methods used were not all the same for given parameters. Sometimes laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days soon after the well is fractured. This data does not control for any of these variables.

[17] Regulated under phenols.

[18] Regulated under phenols.

[19] Regulated under phenols.

[20] Regulated under phenols.

[21] Regulated under alkalinity.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
07440-42-8	Boron	26	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	6	6	11.3	616	3070	mg/L
00075-25-2	Bromoform	29	2	34.8	36.65	38.5	µg/L
07440-43-9	Cadmium	29	5	0.009	0.032	1.2	mg/L
07440-70-2	Calcium	55	52	29.9	5198	34000	mg/L
	Chemical Oxygen Demand	29	29	1480	5500	31900	mg/L
	Chloride	58	58	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	29	2	3.28	3.67	4.06	µg/L
07440-47-3	Chromium	29	3	0.122	5	5.9	mg/L
07440-48-4	Cobalt	25	4	0.03	0.3975	0.58	mg/L
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	29	4	0.01	0.035	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	µg/L
00100-41-4	Ethyl Benzene	29	14	3.3	53.6	164	µg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	58	34	0	47.9	810	mg/L
07439-92-1	Lead	29	2	0.02	0.24	0.46	mg/L
	Lithium	25	4	34.4	55.75	161	mg/L
07439-95-4	Magnesium	58	46	9	563	3190	mg/L
07439-96-5	Manganese	29	15	0.292	2.18	14.5	mg/L
00074-83-9	Methyl Bromide	29	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	29	1	15.6	15.6	15.6	µg/L
07439-98-7	Molybdenum	25	3	0.16	0.72	1.08	mg/L
00091-20-3	Naphthalene	26	1	11.3	11.3	11.3	µg/L
07440-02-0	Nickel	29	6	0.01	0.0465	0.137	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	25	9	5	17	1470	mg/L
	o-Terphenyl [22]	1	1	91.9	91.9	91.9	%Rec
	pH	56	56	1	6.2	8	S.U.
00108-95-2	Phenol	23	1	459	459	459	µg/L
	Phenols	25	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L

[22] Regulated under phenols.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
07440-09-7	Potassium	31	13	59	206	7810	mg/L
07782-49-2	Selenium	29	1	0.058	0.058	0.058	mg/L
07440-22-4	Silver	29	3	0.129	0.204	6.3	mg/L
07440-23-5	Sodium	31	28	83.1	19650	96700	mg/L
07440-24-6	Strontium	30	27	0.501	821	5841	mg/L
14808-79-8	Sulfate (as SO4)	58	45	0	3	1270	mg/L
	Sulfide (as S)	3	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO3)	3	3	2.56	64	64	mg/L
	Surfactants [23]	3	3	0.2	0.22	0.61	mg/L
00127-18-4	Tetrachloroethylene	29	1	5.01	5.01	5.01	µg/L
07440-28-0	Thallium	29	1	0.1	0.1	0.1	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	29	15	2.3	833	3190	µg/L
	Total Dissolved Solids	58	58	1530	93200	337000	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [24]	23	23	69.2	449	1080	mg/L
	Total Suspended Solids	29	29	30.6	146	1910	mg/L
	Xylenes	22	14	16	487	2670	µg/L
07440-66-6	Zinc	29	6	0.028	0.048	0.09	mg/L

[23] Regulated under foaming agents.

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

Table 6.3 - Detected flowback parameters not regulated in New York. Data from limited PA and WV flowback analyses.

Parameter Name [25]	Total Number of Samples	Detects
1,1,1-Trifluorotoluene	1	1
2,5-Dibromotoluene	1	1
Barium Strontium P.S.	24	24
Nitrobenzene-d5	1	1
Scale Inhibitor	24	24
Zirconium	22	1

With respect to surface spills, leaks and container failures, the durability concerns discussed above apply and are magnified by the potential use of large centralized surface impoundments that could be in use for several years, with fluids transferred by pipes laid along the ground. In addition, the large volume of flowback water that may be present at either a well pad or a centralized site increases the importance of appropriate practices, control measures and contingency plans.

6.1.4 Groundwater Impacts Associated With Well Drilling and Construction

The wellbore being drilled, completed or produced, or a nearby wellbore that is ineffectively sealed, could provide subsurface pathways for groundwater pollution from well drilling, flowback or production operations. Pollutants could include:

- turbidity;
- fluids pumped into or flowing from rock formations penetrated by the well; and
- natural gas present in the rock formations penetrated by the well.

These potential impacts are not unique to horizontal wells and are described by the GEIS. The unique aspect of the proposed multi-well development method is that continuous or intermittent activities will occur over a longer period of time at any given well pad. This does not alter the per-well likelihood of impacts from the identified subsurface pathways because existing mitigation measures apply on an individual well basis regardless of how many wells are drilled at the same site. Nevertheless, the potential impacts are acknowledged here and enhanced

[25] This survey did not identify direct regulations for the chemical compounds listed in this table. It is likely that they are indirectly regulated. E.g. Scale inhibitors are composed of several chemical compounds that are likely separately regulated, but the analytical results did not provide the composition of the scale inhibitors. Similarly, specific petroleum hydrocarbons may be regulated, but the analytical results did not provide the composition it tested for.

procedures and mitigation measures are proposed in Chapter 7 because of the concentrated nature of the activity on multi-well pads and the larger fluid volumes and pressures associated with high-volume hydraulic fracturing.

6.1.4.1 Turbidity

The 1992 GEIS stated that "review of Department complaint records revealed that the most commonly validated impact from oil and gas drilling activity on private water supplies was a short-term turbidity problem."[26] This remains the case today. Turbidity, or suspension of solids in the water supply, can result from any aquifer penetration (including water wells, oil and gas wells, mine shafts and construction pilings) if a natural subsurface fracture of sufficient porosity and permeability is present. The majority of these situations correct themselves in a short time.

6.1.4.2 Fluids Pumped Into the Well

ICF International, under its contract with NYSERDA to conduct research in support of the SGEIS preparation, provided the following discussion and analysis with respect to the likelihood of groundwater contamination by fluids pumped into a wellbore for hydraulic fracturing (emphasis added):[27]

> In the 1980s, the American Petroleum Institute (API) analyzed the risk of contamination from properly constructed Class II injection wells to an Underground Source of Drinking Water (USDW) due to corrosion of the casing and failure of the casing cement seal. Although the API did not address the risks for production wells, production wells would be expected to have a lower risk of groundwater contamination due to casing leakage. Unlike Class II injection wells which operate under sustained or frequent positive pressure, a hydraulically fractured production well experiences pressures below the formation pressure except for the short time when fracturing occurs. During production, the wellbore pressure must be less than the formation pressure in order for formation fluids or gas to flow to the well. *Using the API analysis as an upper bound for the risk associated with the injection of hydraulic fracturing fluids, the probability of fracture fluids reaching a USDW due to failures in the casing or casing cement is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells).*

6.1.4.3 Natural Gas Migration

As discussed above, turbidity is typically a short-term problem which corrects itself and the probability of groundwater contamination from fluids pumped into a properly-constructed well is very low. Natural gas migration is a more reasonably anticipated concern with respect to potential

[26] p. FGEIS47

[27] ICF International, Task 1, p. 21

significant adverse impacts. The GEIS in Chapters 9, 10 and 16 describes the following scenarios related to oil and gas well construction where natural gas could migrate into potable groundwater supplies:

- Inadequate depth and integrity of surface casing to isolate potable fresh water supplies from deeper gas-bearing formations;
- Inadequate cement in the annular space around the surface casing, which may be caused by gas channeling or insufficient cement setting time; gas channeling may occur as a result of naturally occurring shallow gas or from installing a long string of surface casing that puts potable water supplies and shallow gas behind the same pipe; and
- Excessive pressure in the annulus between the surface casing and intermediate or production casing. Such pressure could break down the formation at the shoe of the surface casing and result in the potential creation of subsurface pathways outside the surface casing. Excessive pressure could occur if gas infiltrates the annulus because of insufficient production casing cement and the annulus is not vented in accordance with required casing and cementing practices.

As explained in the GEIS, potential migration of natural gas to a water well presents a safety hazard because of its combustible and asphyxiant nature, especially if the natural gas builds up in an enclosed space such as a well shed, house or garage. Well construction practices designed to prevent gas migration would also address other formation fluids such as oil or brine. Although gas migration may not manifest itself until the production phase, its occurrence would result from well construction (i.e., casing and cement) problems.

The GEIS acknowledges that migration of naturally-occurring methane from wetlands, landfills and shallow bedrock can also contaminate water supplies independently or in the absence of any nearby oil and gas activities.

6.1.5 Hydraulic Fracturing Procedure

Concern has been expressed that potential impacts to groundwater from the high-volume hydraulic fracturing procedure itself could result from:

- wellbore failure; or
- movement of unrecovered fracturing fluid out of the target fracture formation through subsurface pathways such as:
    - a nearby poorly constructed or improperly plugged wellbore;

- fractures created by the hydraulic fracturing process;
- natural faults and fractures; and
- movement of fracturing fluids through the interconnected pore spaces in the rocks from the fracture zone to a water well or aquifer.

As summarized in Section 5.18, regulatory officials from 15 states have recently testified that groundwater contamination from the hydraulic fracturing procedure is not known to have occurred despite the procedure's widespread use in many wells over several decades. Nevertheless, NYSERDA contracted ICF International to evaluate factors which affect the likelihood of groundwater contamination from high-volume hydraulic fracturing.[28]

6.1.5.1 Wellbore Failure

As described in Section 6.1.4.2, the probability of fracture fluids reaching an underground source of drinking water (USDW) from properly constructed wells due to subsequent failures in the casing or casing cement due to corrosion is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells).

6.1.5.2 Subsurface Pathways

As explained in Chapter 5 and detailed in Appendix 11, ICF's analysis showed that hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers by movement of fracturing fluids out of the target fracture formation through subsurface pathways when certain natural conditions exist. To guide review and acceptability, these conditions include:

- Maximum depth to the bottom of a potential aquifer ≤ 1,000 feet;
- Minimum depth of the target fracture zone ≥ 2,000 feet;
- Average hydraulic conductivity of intervening strata ≤ 1×10^{-5} cm/sec; and
- Average porosity of intervening strata ≥ 10%.

As noted in Section 2.4.6, a depth of 850 feet to the base of potable water is a commonly used and practical generalization for the maximum depth of potable water in New York. Alpha

[28] ICF Task 1

Environmental, under its contract with NYSERDA, provided the following additional information regarding the Marcellus and Utica Shales:[29]

> The Marcellus and Utica shales dip southward from the respective outcrops of each member, and most of the extent of both shales are found at depths greater than 1,000 feet in New York. There are multiple alternating layers of shale, siltstone, limestone, and other sedimentary rocks overlying the Marcellus and Utica shales. Shale is a natural, low permeability barrier to vertical movement of fluids and typically is considered a cap rock in petroleum reservoirs (Selley, 1998) and an aquitard to groundwater aquifers (Freeze & Cherry, 1979). The varying layers of rocks of different physical characteristics provide a barrier to the propagation of induced hydraulic fractures from targeted zones to overlying rock units (Arthur et al, 2008). The vertical separation and low permeability provide a physical barrier between the gas producing zones and overlying aquifers.

6.1.6 Waste Transport

Drilling and fracturing fluids, mud-drilled cuttings, pit liners, flowback water and produced brine are classified as non-hazardous industrial waste which must be hauled under a New York State Part 364 waste transporter permit issued by the Department. All Part 364 transporters must identify the general category of wastes transported and provide a signed authorization from each destination facility. However, manifesting is generally not required for non-hazardous industrial waste, which prevents tracking and verification of disposal destination on an individual load basis.

6.1.7 Centralized Flowback Water Surface Impoundments

The potential use of large centralized surface impoundments to hold flowback water as part of dilution and reuse system is described in Section 5.12.2.1.

The Dam Safety Regulations described in Section 5.7.2.1, including the requirement for a Protection of Waters Permit, only apply to fresh water surface impoundments and, therefore, would not apply to flowback water surface impoundments. However, the same concerns exist regarding the potential for personal injury, property damage and natural resource damage if a breach should occur.

Adverse impacts to groundwater quality are also a concern relative to large geomembrane-lined surface impoundments. Controlling leakage is a difficult task. An appreciable hydraulic head

---

[29] Alpha, p. 3-3

greatly increases the impact of any liner defect. Under such conditions, even the smallest defect can release significant volumes of contaminated liquid over short periods of time.

In addition, in cases where a single-liner system is not ballasted with a protective soil layer and leakage is trapped in the interstitial area between the liner and liner sub-base, the increased hydraulic pressures and buoyant forces of the geomembrane materials may cause the geomembrane to float. This would typically result in more liner system damage. For deep surface impoundments, the amount of ballast material needed to reduce this problem is appreciable and the placement of this large amount of ballast material also increases the amount of liner system defects. Rapid drawdown of the contained liquid can result in instability of the ballast materials on the surface impoundment's side wall, resulting in catastrophic damage of the liner system.

Conveyances to and from centralized impoundments are also potential pathways for contaminants to reach the environment.

6.1.8 Fluid Discharges

Direct discharge of fluids onto the ground or into surface water bodies from the well pad are prohibited. Discharges will be managed at treatment facilities or in disposal wells.

6.1.8.1 Treatment Facilities

Surface water discharges from water treatment facilities are regulated under the Department's SPDES program. Acceptance by a treatment plant of a waste stream that upsets its system or exceeds its capacity may result in a SPDES permit effluent violation or a violation of water quality standards within the receiving water. Water pollution degrades surface waters, potentially making them unsafe for drinking, fishing, swimming, and other activities or unsuitable for their classified best uses.

Treatability of flowback water is a further concern. Residual fracturing chemicals and naturally-occurring constituents from the rock formation could be present in flowback water and have treatment, sludge disposal, and receiving-water impacts. Salts and dissolved solids may not be sufficiently treated by municipal biological treatment and/or other treatment technologies which are not designed to remove pollutants of this nature. Tables 6.1, 6.2 and 6.3 provide information on flowback water composition based on a limited number of samples from Pennsylvania and West Virginia.

6.1.8.1 Disposal Wells

As stated in the GEIS, the primary environmental consideration with respect to disposal wells is the potential for movement of injected fluids into or between potential underground sources of drinking water. The Department is not proposing to alter its 1992 Finding that proposed disposal wells require individual site-specific review. Therefore, the potential for significant adverse environmental impacts from any proposal to inject flowback water from high-volume hydraulic fracturing into a disposal well will be reviewed on a site-specific basis with consideration to local geology (including faults and seismicity), hydrogeology, nearby wellbores or other potential conduits for fluid migration and other pertinent site-specific factors.

6.1.9 Solids Disposal

Most waste generated at a well site is in liquid form. Rock cuttings and the reserve pit liner are the significant exception. The GEIS describes potential adverse impacts to agricultural operations if materials are buried at too shallow a depth or work their way back up to the surface. Concerns unique to Marcellus development and multi-well pad drilling are discussed below.

6.1.9.1 Naturally Occurring Radioactive Material (NORM) Considerations - Cuttings

Based on the analytical results from field-screening and gamma ray spectroscopy performed on samples of Marcellus shale, NORM levels in cuttings are not likely to pose a problem.

6.1.9.2 Cuttings Volume

As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be one-third greater than that for a conventional, vertical well. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad. The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time. The geotechnical stability and bearing capacity of buried cuttings, if left in a common pit, may need to be reviewed prior to pit closure.[30]

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

6.1.9.3 Cuttings and Liner Associated With Mud-Drilling

Operators have not proposed on-site burial of mud-drilled cuttings, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater.

6.1.10 Potential Impacts to Subsurface NYC Water Supply Infrastructure

In addition to its surface reservoirs, NYC maintains a system of underground tunnels, aqueducts and other underground infrastructure. Drilling directly into one of these system components could compromise the integrity of the system and provide an opening for non-drilling related contaminants to enter the system. However, damage to the system by high-volume hydraulic fracturing is not reasonably anticipated because the target fracturing zones are thousands of feet deeper than any underground water supply infrastructure.

6.1.11 Degradation of New York City's Drinking Water Supply

A comprehensive, long-range watershed protection and water quality management plan has been established by the City of New York, State of New York, federal government, environmental organizations and upstate watershed communities to protect New York City's critical drinking water supply. Successful implementation of this plan has resulted in cost savings to the City and State of an estimated $8 billion that otherwise would be required to filter this water supply and an additional $300 million yearly expense to operate and maintain a filtration plant. The West of Hudson (WOH) Watershed consists of the Ashokan, Cannonsville, Neversink, Pepacton, Roundout and Schoharie Reservoirs (Figure 2.2).

Degradation of New York City's drinking water supply as a result of surface spills is not a reasonably anticipated impact of the proposed activity. Potential impacts to the NYC Watershed are greatly diminished by a number of reasons related to the inherent nature of the activity. These include the following:

- Setback requirements (i.e., required separation distances) will preclude the possibility of the contents of a ruptured additive container or holding tank pouring directly into a reservoir. It would not be possible for an on-site spill to reach a reservoir without first contacting the ground. Soil adsorption would occur and reduce the potential amount of contaminant reaching the reservoir by flowing across the ground.

- Storage containers for fracturing additives must meet USDOT or UN regulations for their respective chemicals, and controls such as valves and gauges are in place to prevent and minimize spills. It is not reasonable to expect multiple containers at one site or sufficient numbers of containers at separate sites to breach simultaneously and spill their entire contents directly into a reservoir without any detection or attempt at mitigation.

- Hydraulic fracturing is an intensely controlled and monitored activity, with more people present on-site than at any other time during the life of the well. On-site personnel and systems would result in the detection and mitigation of any rupture, equipment failure or any other cause for release.

- Construction and operation of the site in accordance with mitigation measures set forth in Chapter 7, including a required Stormwater Pollution Prevention Plan, would provide spill containment and prevent fluids from running off of the well pad.

- Many chemicals, and chemicals dissolved in water, are subject to evaporation during the warmer months of the year, reducing the volumes or concentrations that would reach reservoirs.

- Complete and instantaneous mixing of contaminants in the reservoirs is not likely to occur because of various characteristics of both the chemicals (density, solubility and dispersion rate) and the reservoirs (areal geometry, wind patterns, tributaries, limnology).

- Natural attenuation processes in soil and water such as biodegradation, volatilization, and chemical or biological stabilization, transformation or destruction may also reduce the concentration of contaminants.

6.2 Floodplains

Flooding is hazardous to life, property and structures. Chapter 2 describes Flood Damage Prevention Laws implemented by local communities to govern development in floodplains and floodways and also provides information about recent flooding events in the Susquehanna and Delaware River Basins. The GEIS summarizes the potential impacts of flood damage relative to mud or reserve pits, brine and oil tanks, other fluid tanks, brush debris, erosion and topsoil, bulk supplies (including additives) and accidents. Severe flooding is described as "one of the few ways" that bulk supplies such as additives "might accidentally enter the environment in large quantities."[31] Local and state permitting processes that govern well development activities in floodplains should consider the volume of fluids and materials associated with high-volume hydraulic fracturing and the longer duration of activity at multi-well sites.

6.X Primary and Principal Aquifers

About one quarter of New Yorkers rely on groundwater as a source of potable water. In order to enhance regulatory protection in areas where groundwater resources are most productive and most

[31] GEIS, p. 8-44

vulnerable, the Department of Health, in 1980, identified eighteen Primary Water Supply Aquifers (also referred to simply as Primary Aquifers) across the state. These are defined in the Division of Water Technical & Operational Guidance Series (TOGS) 2.1.3 as "highly productive aquifers presently utilized as sources of water supply by major municipal water supply systems".

Many Principal Aquifers have also been identified and are defined in the DOW TOGS as "highly productive but which are not intensively used as sources of water supply by major municipal systems at the present time".

Because they are largely contained in unconsolidated materials, the high permeability of Primary and Principal Aquifers and shallow depth to the water table, makes these aquifers particularly susceptible to contamination.

6.3 Freshwater Wetlands

State regulation of wetlands is described in Chapter 2. The GEIS summarizes the potential impacts to wetlands associated with interruption of natural drainage, flooding, erosion and sedimentation, brush disposal, increased access and pit location. Potential impacts to downstream wetlands as a result of surface water withdrawal are discussed in Section 6.1.1.4 of this Supplement. Other concerns described herein relative to stormwater runoff and surface spills and releases, including from centralized flowback water surface impoundments, also extend to wetlands.

6.4 Ecosystems and Wildlife

The GEIS discusses the significant habitats known to exist at the time in or near then-existing oil and gas fields (heronries, deer wintering areas, and uncommon, rare and endangered plants). However, the potential mitigation measures for preventing harm to these habitats would also apply to others, such as the Upper Delaware Important Bird Area. Available site-specific options include required setbacks between the disturbance and a habitat or plant community, relocation of a proposed access road or well pad, replanting of cover vegetation in disturbed areas, complete avoidance of specific habitats or endangered plants and seasonal restrictions on specific operations.

Three areas of concern unique to high-volume hydraulic fracturing are:

1) water withdrawals for hydraulic fracturing;

2) potential transfer of invasive species as a result of activities associated with high-volume hydraulic fracturing; and

3) use of centralized flowback water surface impoundments.

Water withdrawals are addressed above in Section 6.1.1. Invasive species and impoundment use are discussed below.

6.4.1 Invasive Species

An invasive species, as defined by §9-1703 of the Environmental Conservation Law (ECL), is a species that is nonnative to the ecosystem under consideration and whose introduction causes or is likely to cause economic or environmental harm or harm to human health. Invasive species can be plants, animals, and other organisms such as microbes, and can impact both terrestrial and aquatic ecosystems.

While natural means such as water currents, weather patterns and migratory animals can transport invasive species, human actions - both intentional and accidental - are the primary means of invasive species introductions to new ecosystems. Once introduced, invasive species usually spread profusely because they often have no native predators or diseases to limit their reproduction and control their population size. As a result, invasive species out-compete native species that have these controls in place, thus diminishing biological diversity, altering natural community structure and, in some cases, changing ecosystem processes. These environmental impacts can further impose economic impacts as well, particularly in the water supply, agricultural and recreational sectors.[32]

The number of vehicle trips associated with high-volume hydraulic fracturing, particularly at multi-well sites, has been identified as an activity which presents the opportunity to transfer invasive terrestrial species. Surface water withdrawals also have the potential to transfer invasive aquatic species.

6.4.1.1 Terrestrial

Terrestrial plant species which are widely recognized as invasive[33] or potentially-invasive in New York State, and are therefore of concern, are listed in Table 6.4 below.

---

[32] ECL §9-1701

[33] As per ECL §9-1703

Table 6.4[34] - Terrestrial Invasive Plant Species In New York State (Interim List) [35]

Terrestrial - Herbaceous	
Common Name	**Scientific Name**
Garlic Mustard	*Alliaria petiolata*
Mugwort	*Artemisia vulgaris*
Brown Knapweed	*Centaurea jacea*
Black Knapweed	*Centaurea nigra*
Spotted Knapweed	*Centaurea stoebe* ssp. *micranthos*
Canada Thistle	*Cirsium arvense*
Bull Thistle	*Cirsium vulgare*
Crown vetch	*Coronilla varia*
Black swallow-wort	*Cynanchum louiseae* (*nigrum*)
European Swallow-wort	*Cynanchum rossicum*
Fuller's Teasel	*Dipsacus fullonum*
Cutleaf Teasel	*Dipsacus laciniatus*
Giant Hogweed	*Heracleum mantegazzianum*
Japanese Stilt Grass	*Microstegium vimineum*
Terrestrial - Vines	
Common Name	**Scientific Name**
Porcelain Berry	*Ampelopsis brevipedunculata*
Oriental Bittersweet	*Celastrus orbiculatus*
Japanese Honeysuckle	*Lonicera japonica*
Mile-a-minute Weed	*Persicaria perfoliata*
Kudzu	*Pueraria montana* var. *lobata*
Terrestrial - Shrubs & Trees	
Common Name	**Scientific Name**
Norway Maple	*Acer platanoides*
Tree of Heaven	*Ailanthus altissima*
Japanese Barberry	*Berberis thunbergii*
Russian Olive	*Elaeagnus angustifolia*
Autumn Olive	*Elaeagnus umbellata*
Glossy Buckthorn	*Frangula alnus*

[34] NYSDEC, DFWMR March 13, 2009 Interim List of Invasive Plant Species in New York State

[35] This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d), but is not the so-called "four-tier lists" referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the "four-tier list" at such time that it becomes available.

Border Privet	*Ligustrum obtusifolium*
Amur Honeysuckle	*Lonicera maackii*
Shrub Honeysuckles	*Lonicera morrowii/tatarica/x bella*
Bradford Pear	*Pyrus calleryana*
Common Buckthorn	*Rhamnus cathartica*
Black Locust	*Robinia pseudoacacia*
Multiflora Rose	*Rosa multiflora*

Operations involving land disturbance such as the construction of well pads, access roads and engineered surface impoundments for both fresh water and flowback fluid storage have the potential to both introduce and transfer invasive species populations. Machinery and equipment used to remove vegetation and soil may come in contact with invasive plant species that exist at the site and may inadvertently transfer those species' seeds, roots, or other viable plant parts via tires, treads/tracks, buckets, etc. to another location on site, to a separate project site, or to any location in between.

The top soil that is stripped from the surface of the site during construction and set aside for re-use during reclamation also presents an opportunity for the establishment of an invasive species population if it is left exposed. Additionally, fill sources (e.g., gravel, crushed stone) brought to the well site for construction purposes also have the potential to act as a pathway for invasive species transfer if the fill source itself contains viable plant parts, seeds, or roots.

6.4.1.2 Aquatic

The presence of non-indigenous aquatic invasive species in New York State waters is recognized, and, therefore, operations associated with the withdrawal, transport, and use of water for horizontal well drilling and high volume hydraulic fracturing operations have the potential to transfer invasive species. Species of concern include, but are not necessarily limited to; zebra mussels, eurasian watermilfoil, alewife, water chestnut, fanwort, curly-leaf pondweed, round goby, white perch, didymo, and the spiny water flea. Other aquatic, wetland and littoral plant species that are of concern due to their status as invasive[36] or potentially-invasive in New York State are listed in Table 6.5.

[36] As per ECL §9-1703

Table 6.5[37] - Aquatic, Wetland & Littoral Invasive Plant Species in New York State (Interim List) [38]

Floating & Submerged Aquatic	
Common Name	**Scientific Name**
Carolina Fanwort	*Cabomba caroliniana*
Rock Snot (diatom)	*Didymosphenia geminata*
Brazilian Elodea	*Egeria densa*
Water thyme	*Hydrilla verticillata*
European Frog's Bit	*Hydrocharis morus-ranae*
Floating Water Primrose	*Ludwigia peploides*
Parrot-feather	*Myriophyllum aquaticum*
Variable Watermilfoil	*Myriophyllum heterophyllum*
Eurasian Watermilfoil	*Myriophyllum spicatum*
Brittle Naiad	*Najas minor*
Starry Stonewort (green alga)	*Nitellopsis obtusa*
Yellow Floating Heart	*Nymphoides peltata*
Water-lettuce	*Pistia stratiotes*
Curly-leaf Pondweed	*Potamogeton crispus*
Water Chestnut	*Trapa natans*
Emergent Wetland & Littoral	
Common Name	**Scientific Name**
Flowering Rush	*Butomus umbellatus*
Japanese Knotweed	*Fallopia japonica*
Giant Knotweed	*Fallopia sachalinensis*
Yellow Iris	*Iris pseudacorus*
Purple Loosestrife	*Lythrum salicaria*
Reed Canarygrass	*Phalaris arundinacea*
Common Reed- nonnative variety	*Phragmites australis* var. *australis*

Invasive species may be transported with the fresh water withdrawn for, but not used for drilling or hydraulic fracturing. Invasive species may potentially be transferred to a new area or watershed if unused water containing such species is later discharged at another location. Other

---

[37] NYSDEC, DFWMR March 13, 2009 Interim List of Invasive Plant Species In New York State

[38] This list was prepared pursuant to ECL §9-1705(5)(b) and ECL §9-1709(2)(d)), but is not the so-called “four-tier lists” referenced in ECL §9-1705(5)(h). As such the interim list is expected to be supplanted by the “four-tier list” at such time that it becomes available.

potential mechanisms for the possible transfer of invasive aquatic species may include trucks, hoses, pipelines and other equipment used for water withdrawal and transport.

6.4.2 Centralized Flowback Water Surface Impoundments

Division of Fish, Wildlife and Marine Resources (DFWMR) staff in the Department reviewed Tables 6.2 and 6.3 and concluded that the salt content of the flowback water should discourage most wildlife species from using the surface impoundments. One notable exception is waterfowl. There is a chance that waterfowl might use the impoundments during migration or during winter if water remains unfrozen and if the impoundment is located near feeding areas like corn fields. However, DFWMR staff believe that the flowback water is probably not acutely toxic to waterfowl from short term contact, although adverse effects might result from more prolonged exposure. Vegetation growing immediately around the impoundments, for example in soil used as liner ballast on the inside embankments, could serve as an attractive nuisance and encourage waterfowl to use the impoundments, perhaps as locations to rest during migration. For that reason, the banks of such impoundments should be kept as bare as possible. If waterfowl or other birds are attracted to the ponds despite the salinity and lack of vegetation, then some sort of surface cover, such as netting, “bird balls” or other exclusion measure would have to be considered.

6.5 Air Quality

6.5.1 Regulatory Analysis

Appendices 16 and 17 contain general information on applicability of NOx RACT and proposed revisions of 40 CFR Part 63 Subpart ZZZZ (Engine MACT) for Natural Gas Production Facilities. Appendix 18 contains information on the Clean Air Act regulatory definition of “facility” for the oil and gas industry. Specific information regarding emission sources that have potential regulatory implications is presented below.

6.5.1.1 NOx - Internal Combustion Engine Emissions

Compressor Engine Exhausts

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions.

Well Drilling and Hydraulic Fracturing Operations

Oil and gas drilling rigs require substantial power to drill and case wellbores to the depths of hydrocarbon deposits. In the Marcellus Shale, this power will typically be provided by transportable diesel engines, which generate exhaust from the burning of diesel fuel. After the wellbore is drilled to the target formation, additional power is needed to operate the pumps that move large quantities of water, sand, or chemicals into the target formation at high pressure to hydraulically fracture the shale.

The preferred method for calculating engine emissions is to use emission factors provided by the engine manufacturer. If these cannot be obtained, a preliminary emissions estimate can be made using EPA AP-42 emission factors. The most commonly used tables are below.

AP-42 Table 3.2-1: Emission Factors for Uncontrolled Natural Gas-Fired Engines

Pollutant	**2-cycle lean burn**		**4-cycle lean burn**		**4-cycle rich burn**	
	g/Hp-hr (power input)	**lb/MMBtu (fuel input)**	**g/Hp-hr (power input)**	**lb/MMBtu (fuel input)**	**g/Hp-hr (power input)**	**lb/MMBtu (fuel input)**
NO_X	10.9	2.7	11.8	3.2	10.0	2.3
CO	1.5	0.38	1.6	0.42	8.6	1.6
TOC [1]	5.9	1.5	5.0	1.3	1.2	0.27

TOC is total organic compounds (sometimes referred to as THC). To determine VOC emissions calculate TOC emissions and multiply the answer by the VOC weight fraction of the fuel gas.

AP-42 Table 3.3-1: Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines

Pollutant	**Gasoline Fuel**		**Diesel Fuel**	
	g/Hp-hr (power output)	**lb/MMBtu (fuel input)**	**g/Hp-hr (power output)**	**lb/MMBtu (fuel input)**
NO_X	5.0	1.63	14.1	4.41
CO	3.16	0.99	3.03	0.95
TOC				
exhaust	6.8	2.10	1.12	0.35
evaporative	0.30	0.09	0.00	0.00
crankcase	2.2	0.69	0.02	0.01
refueling	0.5	0.15	0.00	0.00

Engine Emissions Example Calculations

A characterization of the significant NOx emission sources during the three operational phases of horizontally drilled, hydraulically fractured natural gas wells is as follows:

1. <u>Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Drilling Phase</u>

For a diesel engine drive total of 5400 Hp drilling rig power*, using NOx emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus shale formation, a representative NOx emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NOx emission would be:

NO_X emissions = (6.4 g/Hp-hr) × (5400 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 333.7 TPY

*Engine information provided by Chesapeake Energy

The actual emissions from the engines will likely be much lower than the above PTE estimate, depending on the number of wells drilled at a well site in a given year.

2. <u>Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Completion Phase</u>

For diesel-drive 2333 Hp frac pump engine(s)*, using NOx emission factor data from engine specification data received from natural gas production companies currently operating in the Marcellus shale formation, a representative NOx emission factor of 6.4 g/Hp-hr is used in this example. For purposes of estimating the Potential to Emit (PTE) for the engines, continuous year-round operation is assumed. The estimated NOx emission would be:

NO_X emissions = (6.4 g/Hp-hr) × (2333 Hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 144.1 TPY

*Engine information provided by Chesapeake Energy

The actual emissions from the engines will likely be lower than the above PTE estimate, depending on the number of wells drilled and the number of hydraulic fracturing jobs performed at a well site in a given year.

3. <u>Horizontally Drilled/High-Volume Hydraulically Fractured Wells - Production Phase</u>

Using the most recent natural gas compressor station DEC Region 8 permit application information, a NOx emission factor 2.0 g/Hp-hr was chosen as more reasonable (yet still conservative) than AP-42 emission data. The maximum site-rated horsepower is 2500 Hp*. The engine(s) is expected to run year round (8760 hr/yr).

NO_X emissions = (2.0 g/Hp-hr) × (2500 Hp) × (8760 hr/yr) × (ton/2000 lb) ×(1 lb/453.6 g) = 48.3 TPY

*Engine information provided by Chesapeake Energy

The total PTE of the two types of engines exceeds the major source threshold, assuming continuous operation for a full year. However, because the actual emissions are likely to be much lower due to the inherent intermittent nature of these wellsite operations, facilities may want to investigate capping the emissions below the thresholds. This would enable permitting under shorter State facility permitting timeframes. It would also eliminate the applicability of NOx RACT regulations. Since the engines in the example comply with the NOx RACT emission limits, avoiding the rule applicability will avoid cumbersome monitoring requirements that were designed for permanently located engines. In addition to NOx RACT requirements, Title V permitting requirements would also apply to other air pollutants such as carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), ozone (as volatile organic compounds (VOC)), and elemental lead, with the same emission thresholds as for NOx. Review of other emission information for these engines, such as CO and PM emission factor data, reveal an unlikely possibility of reaching major source thresholds triggering Title V permitting requirements for these facilities.

6.5.1.2 Natural Gas Production Facilities NESHAP 40 CFR Part 63, Subpart HH (Glycol Dehydrators)

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. “Lean” TEG contacts the wet gas and absorbs water. The TEG is then considered “rich”. As the rich TEG is passed through a flash separator and/or reboiler for regeneration, steam containing hydrocarbon vapors is released from it. The vapors are then vented from the dehydration unit flash separator and/or reboiler still vent.

Dehydration units with a natural gas throughput below 3 MMscf per day or benzene emissions below 1 tpy are exempted from the control, monitoring and recordkeeping requirements of this subpart. Although the natural gas throughput of some Marcellus horizontal shale wells in New York State could conceivably be above 3 MMscf, preliminary analysis of gas produced at Marcellus horizontal shale gas well sites in states adjacent to New York State indicate a benzene content below the exemption threshold of 1 tpy, for the anticipated range of annual gas production for wells in the Marcellus. However, the affected natural gas production facilities will still likely be required to maintain records of the exemption determination as outlined in 40 CFR 63.774(d) (1) (ii). Sources with throughput of 3 MMscf/day or greater and benzene emissions of 1.0 tpy or greater are subject to emission reduction requirements of the rule. This does not necessarily mean control, depending on the location of the affected emission sources relative to "urbanized areas (UA) plus offset" or to "urban clusters (UC) with a population of 10,000 or greater" as defined in the rule.

6.5.1.3 Flaring Versus Venting of Wellsite Air Emissions

Well completion activities include hydraulic fracturing of the well and a flowback period to clean the well of flowback water and any excess sand (frac proppant) that may return out of the well. Flowback water is routed through separation equipment to separate water, gas, and sand. Initially, only a small amount of gas is vented for a period of time. Once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas to a sales gas line. Recovering the gas to a sales gas line is called a "reduced emissions completion (REC)" or a "green completion."

Normally the flowback gas is flared when there is insufficient pressure to enter a sales line, or if a sales line is not available. There is no current requirement for REC, and the PSC does not now typically authorize construction of sales lines before the first well is drilled on a pad (see Section 5.16.8.1 for a discussion of the PSC role and a presentation of reasons why pre-authorization of gathering lines have been suggested), therefore, estimates of emissions from both flaring and venting of flowback gas are included in the emissions tables in Section 6.5.1.5**.**

Also, during drilling, gaseous zones can sometimes be encountered such that some gas is returned with the drilling fluid, which is referred to as a gas "kick". For safety reasons, the drilling fluid is circulated through a "mud-gas separator" as the gas kick is circulated out of the wellbore. Circulating the kick through the mud-gas separator diverts the gas away from the rig personnel.

Any gas from such a kick is vented to the main vent line or a separate line normally run adjacent to the main vent line.

Drilling in a shale formation does not result in significant gas adsorption into the drilling fluid as the shale has not yet been fractured. Experience in the Marcellus thus far has shown few, if any, encounters with gas kicks during drilling. However, to account for the potential of a gas kick where a "wet" gas from another formation might result in some gas being emitted from the mud-gas separator, an assumed wet-gas composition was used to estimate emissions. For a worst-case scenario, a potential vent rate of 5,000 standard cubic feet (scf) vented in one hour during the drilling phase of a single well is assumed in the analysis.

Gas from the Marcellus Shale in New York is expected to be very "dry", i.e., have little or no VOC content, and "sweet", i.e. have little or no hydrogen sulfide. Except for drilling emissions, two sets of emissions estimates are made to enable comparison of emissions of VOC and HAP from both dry gas production and wet gas production.

6.5.1.4 Number of Wells Per Pad Site

Drilling as many wells as possible from a single well pad provides for substantial environmental benefits from less road construction, surface disturbance, etc. Also, experience shows that average drilling time in days can be improved as more experience is gained in a shale play. However, at present typical drilling rates, it is expected that no more than 10 wells could be drilled, completed, and hooked up to production in any 12-month period. This is because of the interval time periods between drilling, completion, and production such as when the drilling rig must be moved over a distance in order to drill the next well, time to move fracturing equipment on and off the well site, time to hook up and disconnect fracturing equipment, etc. Therefore, the analysis is based on an assumption of 10 wells per site per year.

6.5.1.5 Emissions Tables

Estimated annual emissions from drilling, completion and production activities, based on the placement of a maximum of 10 wells at a wellsite, processing both "dry" and "wet" gas, under both venting and flaring options of well air emissions, are presented in the following tables (based on reference data provided by ALL Consulting, LLC "Horizontally Drilled / High - Volume Hydraulically Fractured Wells Air Emissions Data", dated August 26, 2009):

Table 6.6 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Flaring (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	3.67	5.56
NOx	36.0	14.4	3.77	54.17	12.24	66.41
CO	20.7	6.6	9.20	36.5	61.2	97.7
VOC	1.88	0.6	2.43	4.91	1.76	6.67
SO_2	0.042	0.015	0.066	0.123	0.54	0.663
Total HAP	0.22	0.06	0.029	0.309	0.20	0.509

Table 6.7 - Estimated Wellsite Emissions (Dry Gas) - Flowback Gas Venting (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	0.0	1.89
NOx	36.0	14.4	3.77	54.17	0.0	54.17
CO	20.7	6.6	9.20	36.5	0.0	36.5
VOC	1.88	0.6	2.43	4.91	1.50	6.41
SO_2	0.042	0.015	0.066	0.123	0.0	0.123
Total HAP	0.22	0.06	0.029	0.309	0.0	0.309

Table 6.8 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Flaring (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	3.67	5.56
NOx	36.0	14.4	3.77	54.17	12.24	66.41
CO	20.7	6.6	9.20	36.5	61.2	97.7
VOC	1.88	0.6	2.43	4.91	64.8	69.71
SO_2	0.042	0.015	0.066	0.123	0.54	0.663
Total HAP	0.22	0.06	0.31	0.59	1.73	2.32

Table 6.9 - Estimated Wellsite Emissions (Wet Gas) - Flowback Gas Venting (Tons/Year)

	Drilling	Completion	Production	Subtotal	Flowback Gas	Total
PM	1.20	0.46	0.23	1.89	0.0	1.89
NOx	36.0	14.4	3.77	54.17	0.0	54.17
CO	20.7	6.6	9.20	36.5	0.0	36.5

VOC	1.88	0.6	2.43	4.91	54.75	59.66
SO_2	0.042	0.015	0.066	0.123	0.0	0.123
Total HAP	0.22	0.06	0.31	0.59	0.0037	0.594

6.5.1.6 Offsite Gas Gathering Station Engine

For gas gathering compression, it is anticipated that most operators will select a large 4-stroke lean-burn engine because of its fuel efficiency. A typical compressor engine is the 1,775-hp Caterpillar G3606, which is the engine model used for the analysis.

A proposed amendment to NESHAP Subpart ZZZZ will place very strict limits on formaldehyde emissions from reciprocating internal combustion engines. In the near future, 4-stroke lean-burn engines will likely be required to have an oxidation catalyst that will reduce formaldehyde emissions by approximately 90%.

The annual emissions data for a typical gas gathering compressor engine is given in Table 6.21 below (based on reference data provided by ALL Consulting, LLC "Horizontally Drilled/High - Volume Hydraulically Fractured Wells Air Emissions Data", dated August 26, 2009):

Table 6.10 - Estimated Off-Site Compressor Station Emissions (Tons/Year)

Component	Uncontrolled 4-Stroke Lean Burn Engine
PM	0.514
NOx	33.29
CO	65.7
SO_2	0.0
Total VOC	16.64
Total HAP	2.74

6.5.1.7 Natural Gas Condensate Tanks

Fluids that are brought to the surface during production at natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids (known as condensate). Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. Hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. Initial analysis of natural gas produced at Marcellus shale horizontal gas well sites in states adjacent to New York State indicates insufficient BTEX and other liquid hydrocarbon content to justify installation of collection and storage equipment for natural gas liquids.

6.5.1.8 Potential Emission of Fracturing Water Additives from Surface Impoundments

Fracturing fluid currently being utilized in the Marcellus Shale is comprised mainly of water with sand, polymers and various chemical additives. When the fluid is flowed back out of the well, it is typically stored in tanks or lined pits until it can be trucked to a waste water treatment facility or other disposal facility; storage in tanks minimizes atmospheric contamination from the additives in the flowback.

However, recent industry responses indicate that fluid from multiple well sites may be accumulated for longer term storage at a centralized impoundment designed for the storage of flowback fluid. While the actual concentrations of the additives of concern in the centralized impoundments may be small, it is premature to assume that the contribution of these additives to air emissions is negligible.

Given that NYS Marcellus Shale is in the early stages of development, common practices for water handling have not been developed, but a worst case scenario can be developed from available information and surveys of what NYS Marcellus Shale operators plan to implement. One operator reports that water used for hydraulic fracturing of wells in the NYS Marcellus Shale is usually trucked to the site. It is estimated that over 800,000 gallons of water are needed per hydraulic fracturing stage. Because of the long length of each horizontal well, several fracturing stages are required per well. An entire hydraulic fracturing job may use as much as 5,000,000 gallons of water. In general, water can be stored in tanks, a lined pit, or in centralized impoundments servicing multiple pads. Water can be stored in large, portable water tanks at the well site, and then pumped from the water tanks down-hole, with one Marcellus Shale operator reporting using frac tanks to capture the flowback water and produced water from the formation. A lined pit is also an option for capturing flowback water, and operators report plans to construct lined pits at the wellsite for temporary storage of flowback water.

One NYS Marcellus Shale operator plans to use a centralized impoundment for the duration of the development period, up to three years. Analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals potential for emissions of hazardous air pollutants (HAPs), in particular methanol, from the recovered (flowback) water stored in central impoundments. This methanol is present as a major component of the surfactants, cross-linker solutions, scale inhibitors and iron control solutions used as additives in the frac water . Current field experience indicates that an approximately 25% recovery of fracturing water from Marcellus shale wells may be expected. Thus, using a 25% recovery factor of a nominal 5,000,000 gallons of frac water used for each well, an estimated 6,500 pounds (3.25 tons) of methanol will be contained in the flow- back water. Since methanol has a relatively high vapor pressure, its release to the atmosphere could possibly occur within only about two days after the recovered water is transferred to the impoundment. Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission of 32.5 tons (i.e., “major” quantity of HAP) is theoretically possible at a central impoundment.

EPA stated in its original rulemaking documents for 40 CFR 63 Subpart HH (63 FR 6388, February 6, 1998), that surface impoundments and wastewater operations, among other sources, were considered for potential regulation, but were exempted. However, air quality modeling analysis performed to assess the potential air impacts of unconventional natural gas production operations in the Marcellus Shale in support of the SGEIS identified methanol emissions from centralized flowback water surface impoundments as a pollutant of concern. Thus, this identified emission could be subject to environmental impact assessment and mitigation as prescribed by 6 NYCRR Part 617 State Environmental Quality Review (SEQR).

6.5.2 Air Quality Impact Assessment

6.5.2.1 Introduction

As part of the Department’s effort to address the potential air quality impacts of horizontal drilling and hydraulic fracturing activities in the Marcellus Shale and other gas low permeability reservoirs, an air quality modeling analysis was undertaken. The assessment was carried out to determine whether the various expected operations at a “typical” multi-well site would have the potential for any adverse air quality impacts. A number of issues raised by public comments during the SGEIS scoping process were also addressed by subsequently developing information on operational scenarios specific to multi-well horizontal drilling and hydraulic fracturing, which allowed DEC’s Division of Air Resources (DAR) to conduct the modeling assessment, and to determine possible air permitting requirements. This section presents the air quality analysis undertaken by DAR staff based on operational and emissions information supplied mainly by industry and its consultant in a submission hereafter referred to as the "industry report"39. To a limited extent, certain supplemental information from ICF International's report to NYSERDA40 was also used. The applicability determinations of DEC air permitting regulations and the verification approach to the emission calculations are contained in Section 6.5.2.

To the extent that the information being used was for the modeling of a generic multi-well site and its operations, it was necessary to reconcile and define a "worst case" scenario for the various activities in terms of expected impacts. Certain assumptions were made on the type and sizes of equipment to be used, the potential for simultaneous operation of the equipment on a short-term basis (i.e. hourly and daily), and the duration of these activities over a period of a year in order to be able to compare impacts to the corresponding ambient thresholds. For other air emissions related specifically to impoundments containing the flowback of various additives to the hydraulic fracturing water, neither industry nor the ICF report contained the necessary emission rate data. However, chemical composition information on the additives used in hydraulic fracturing water was made available to DEC by well-service and chemical supply companies which was used by DAR to develop the necessary emission rates, with a request to industry for "verification" of intermediate data needed for these calculations.

The air quality analysis relied upon recommended EPA and DEC air dispersion modeling procedures to determine "worst case" impacts of the various operations and activities identified for the horizontal multi-well sites. Dispersion modeling is an acceptable tool, and at times the only option, to determine the impacts of many source types in permitting activities and environmental impact statements. Where necessary, the analysis approach relied on assumed worst case emissions and operations scenarios due to not only the nature of this generic assessment, but also because detailed model input data for the sources and their relative locations on a typical well pad cannot be simply identified or analyzed. Modeling was performed for various criteria pollutants (those with National Ambient Air Quality Standards, NAAQS) and a set of non-criteria pollutants (including toxics) for which New York has established a standard or other ambient threshold levels. Some of these toxic pollutants were identified in public comments

[39] ALL Consulting, 2009.

[40] ICF, 2009.

during the SGEIS scoping process and were quantified to the extent possible for both the modeling and applicability determinations.

The following sections describe the basic source categories and operations at a typical multi-well site with hydraulic fracturing, the modeling procedures and necessary input data, the resultant impacts, and a set of conclusions drawn from these results. These conclusions are meant to guide the set of conditions under which a site specific assessment might or might not be necessary. These conditions are summarized in Chapter 3.

6.5.2.2 Sources of Air Emissions and Operational Scenarios.

In order to properly estimate the air quality impacts of the set of sources at a single pad with multiple horizontal wells, the operating scenarios and associated air emission sources must be correctly represented. Since these operations have a number of interdependent as well as independent components, the Department has defined both the short-term and long term emission scenarios from the various source types in order to predict conservative, yet realistic impacts. The information used to determine the emission sources and their operating scenarios and constraints, as well as the associated emission rates and parameters, were provided by the industry report, while certain operational scenario restrictions were presented in the ICF report, which reflects information obtained from industry with drilling activities in other states. Where necessary, further data supplied by industry or determined appropriate by DMN was used to fill in data gaps or to make assumptions. In some of these instances, the lack of specific information necessitated a worst-case assumption be made for the purposes of the modeling exercise. Examples of the latter include defining “ambient air” based on the proximity of public access to the centralized impoundment and the likely structure dimensions to calculate their influence on the stack plumes.

The industry and ICF reports indicate three distinct operation stages and four distinct source types of air emissions for developing a representative horizontally-drilled multi-well pad. The phases are drilling, completion, and gas production, each of which has either similar or distinct sources of air emissions. These phases and the potential air pollution sources are presented in the industry report, section 2.1.5 and Exhibit 2.2.1 of the ICF report, and in Chapter 5 of the SGEIS, and will only be briefly noted herein. Of the various potential sources of air emissions, a number have distinct quantifiable and continuous emissions which lend themselves to modeling. On the other hand, the ICF report also identifies other generic sources of minor fugitive emissions (e.g. mud return lines) or of emergency release type (e.g. BOP stack), or of a pollutant which is quantified only as of “generic” nature (total VOCs for tanks) which cannot be modeled within the current scope of analysis. However, in instances where speciated VOCs or Hazardous Air Pollutants (HAPs) are provided, such as for the glycol dehydrator and flowback venting of gas, the modeling was used to predict impacts which were then compared to available ambient thresholds.

The total operations associated with well drilling can be assigned to four “types” of potential sources: 1) combustion from engines, compressors, line heaters and flares; 2) short-term venting of gas constituents which are not flared, 3) chemicals in the additives used for hydraulic fracturing and which remain in the flowback water to be potentially deposited in onsite or off site impoundments; and 4) emissions from truck activities. Each of these source categories have limitations in terms of the size and number of the needed equipment, their possible simultaneous operations over a short-term period (e.g. 24 hour), and the time frames over which these equipment or activities could occur over a period of one year, which effects the corresponding annual impacts. Some of these limitations are described in the industry report. These limitations and further assumptions were taken into account in the modeling analysis, as further discussed in Section 6.5.2.3.

Many of the sources for which the industry report tabulates the drilling, completion and production activities are depicted in the typical site layout represented schematically in Exhibit 2.1.3 of the ICF report. The single pad for multi-horizontal wells is confined to an area of about 150 meters (m) by 150 meters as a worst case size of the operations. From this single pad, wells are drilled in horizontal direction to develop an area of about one square mile. The industry report notes the possibility of up to ten horizontal wells being eventually drilled and completed per pad over a year’s time, while the ICF report notes that simultaneous drilling and completion on the same pad will be limited to a single operation for each. This limitation was determined appropriate by DMN for analysis of short-term impacts. Thus, the simultaneous operations on a pad for the assessment of impacts of 24 hours or less is limited to the equipment necessary to drill one well and complete another. In addition, according to DMN, there is a potential that a third well’s emissions could be flared at the same time as these latter operations. Thus, this source was also included in the simultaneous operation scenario for criteria pollutants. It should be noted that no emissions of criteria pollutants resulting from uncontrolled venting of the gas are expected. The other sources which could emit criteria pollutants are associated with the production phase operations; that is, the off-site compressors and line heaters could be operating simultaneously with the single pad drilling, completion and flaring operations. The industry report provides data for a possible "on-site" line heater instead of at the compressor station and this source was placed on the pad area and provides for a more conservative impact.

The industry report also provides emission data for the non-criteria pollutants as species of VOCs or HAPs associated with both combustion and gas venting. Review of this information indicates two essentially different sets of sources which can be treated independently in the modeling analysis. The first set is the gas venting sources: the mud-gas separator, the flowback gas venting, and the glycol dehydrator. These sources emit a distinct set of pollutants associated with the "wet" gas scenario, defined in the industry report as containing "heavier" hydrocarbons such as benzene. The industry and ICF reports note that gas samples in the Marcellus Shale have not detected these heavier species of VOC, nor hydrogen sulfide (H_2S). However, the industry report also notes the possibility of gas pockets with "wet" gas and provides associated emissions. To be comprehensive, the modeling analysis has calculated the impacts of these species which could be realized in the westernmost part of New York according to DMN.

The industry report also notes that gas venting is a relatively short-term phenomenon, especially during the flowback period where the vented gas is preferentially flared after a few hours of venting. Since there are essentially no simultaneous short-term emissions expected of the same pollutants at the pad other than the venting, coupled with the clear dominance of the flowback venting emissions of these pollutants, the modeling was simplified for this scenario and only the short-term impacts were determined, as described in more detail in Section 6.5.1.3. The second set of non-criteria pollutant emissions presented in the industry report is associated mainly with combustion sources. These non-criteria pollutants could be emitted over much longer time periods, considering these sources are operated over these longer periods, both per-well drilling activity and potential multi-well operations over a given year. Thus, for these pollutants, both short-term and annual impacts were calculated. It should be noted that, since the glycol dehydrator could operate for a full year also, its emissions of the same pollutants as those due to combustion were also included in this assessment of both short-term and annual toxic impacts. Furthermore, the flare emissions are included in the combustion scenario (and not in the venting), as the flaring of flowback gas results in over 95% destruction of these pollutants.

In addition, due to the conversion of H_2S to SO_2 during flaring, the flare was included in the criteria pollutant simultaneous operations scenario modeling. Table 6.11 summarizes the set of sources and the pollutants which have been modeled for the various simultaneous operations for short-term impacts. The specific modeling configuration and emissions data of the various sources are discussed in Section 6.5.2.3.

On the other hand, the emissions of the chemicals associated with the additive compounds used in the hydraulic fracturing operations during the completion phase and which might be deposited in the flowback water impoundments, are modeled distinctly from the other sources. This is because none in the set of chemicals chosen for the Department's modeling exercise are in common with the pollutants modeled for other operations. It should be noted that both the ICF report and certain industry operators took the position that there are essentially negligible emissions of these chemicals into the air and, thus, no mitigation measures are necessary. It is prudent to quantify these emissions and explicitly determine the consequent impacts. Thus, the Department has performed an assessment of a set of representative chemicals in the additives. Details of how this set was chosen and emissions calculated are presented in Section 6.5.2.3. The ICF report presents the size of an onsite impoundment as about 15m by 45m and also noted the possibility of a larger centralized impoundment with a size of 150m by 150m. Both of these scenarios have been modeled.

Many of the pollutants have annual ambient standards and thresholds and, thus, the modeling of the corresponding annual impacts should account for the long-term emission rates. It is common practice in modeling guideline requirements to conservatively use the maximum short-term emission rates for a full year of operations in instances where there are no long term restrictions on operations or when industry does not provide such verifiable limitations on its emissions. For some of the operations during Marcellus Shale drilling, these annual emissions will likely be much lower even if up to 10 wells are drilled at a pad in a year. The industry report discusses some of these operational restrictions and presents data for "average" conditions expected during all phases of operations. These average emissions are calculated for the specific time frames of a certain operation related to drilling and completion of one well; in addition to these average emissions, the report provided the maximum days of such operations. For example, the average emissions for the engines used for hydraulic fracturing are noted to be lower than the corresponding maximum short-term emissions due to the various "stages" of that operation. In addition, however, the whole fracturing operation of a single well takes only 2 to 3 days, which must be taken into account if the annual emissions are to be properly calculated. Another example is the flaring operation. Although the emissions from the flare are the same in the average and maximum tables, this operation is of a very limited nature. The industry report notes 3 days as the period of actual flaring prior to the production phase.

Since each pad could potentially have up to ten wells drilled over a year, it is also necessary to incorporate these limitations in the potential annual emissions in order not to predict unrealistically high annual impacts. These considerations are addressed further in the emission data discussions and in the resultant impact sections. On the other hand, the production phase operations are expected to occur over a full year and are, thus, conservatively modeled at the maximum short-term emission rates, as required by EPA and DEC modeling guidelines.

For the annual impacts from the impoundment emissions, a set of considerations and assumptions was made. Current regulations on well drilling require the removal of the flowback water from on site operations within 45 days of end of completion. However, for multi-well drilling operations, industry information submitted previously had indicated that this time-frame would be impractical from a few standpoints, including the fact that up to half of the maximum number of wells per pad could be drilled and completed on a "continuous" basis, while the rest could be done at a later time. The industry report notes the possibility of drilling up to ten wells in a year at a pad. This implies that additives could be "replenished" into the impoundment for a considerable amount of time over a year. In addition, certain industry operators indicated a desire to have a larger centralized impoundment which could serve multiple pads over a two mile square area. This means that flowback water from up to 4 pads could potentially be put into this impoundment, and the emissions from this centralized impoundment could easily be considered "quasi-continuous" over a year. Industry has also indicated a desire to keep at least the offsite impoundments open for up to three years. Thus, the modeling for annual impacts from impoundments was initially performed assuming year long "emissions" at the maximum calculated levels, and the resultant concentrations were compared to the corresponding annual thresholds to determine the consequences of this scenario.

The last type of emission source associated with the multi-well operations is truck traffic. An estimate of the number of trucks needed for the various activities at a single well pad, including movement of ancillary equipment, delivery of fresh water and proppant/additives, and the hauling of flowback is presented in Section 6.11. It should be first noted that direct emissions from mobile sources are controlled under Title II of the Clean Air Act (CAA) and are specifically exempt from permitting activities. Thus, these emissions are also not addressed in a modeling analysis, with two exceptions. At times, the indirect emissions of fugitive particulate matter are modeled when estimates of emissions are large. The latter occurs mainly due to poor dust control measures and the best approach to mitigate these emissions is to have a dust control plan. In addition, emissions of PM2.5 from mobile sources associated with a project and which occur on-site are to be addressed by DEC's Commissioner's Policy CP-33[41]. Again, if these emissions are large enough, a modeling analysis is performed for an EIS. The emission calculations are not to include those associated with incidental roadway traffic away from the onsite operations.

Emissions of both PM10 and PM2.5 due to truck operations were provided by DAR's Mobile Source Panning staff based on the movement of total number of trucks on-site for the drilling of one well. These emissions were then multiplied by the 10 potential wells which might be drilled over a year, and resulted in relatively minor quantities of 0.2 tpy maximum PM2.5 emissions. This is consistent with the limited number and limited use of trucks at the well pad. These emissions are well below the CP-33 threshold of 15tpy. Thus, no modeling was performed for these pollutants and any necessary mitigation scheme for these would be the application of an appropriate dust control methods and similar limitations on truck usage, such as inordinate idling.

6.5.2.3 Modeling Procedures

EPA and DEC guidelines[42] on air dispersion modeling recommend a set of models and associated procedures for assessing impacts for a given application. For stationary sources with "non-reactive" pollutants and near-field impacts, the refined AERMOD model (latest version, 07026) and its meteorological and terrain preprocessors is best suited to simulate the impacts of the sources and pollutants identified in the Marcellus Shale and other gas reservoir operations. This model is capable of providing impacts for various averaging times using point, volume or area source characteristics, using hourly meteorological data and a set of receptor locations in the surrounding area as inputs. The model simulates the impact of "inert" pollutants such as SO_2, NO_2, CO, and particulates without taking into account any removal or chemical conversions in

---

[41] *Assessing and Mitigating Impacts of Fine Particulate Matter Emissions.* See: http://www.dec.ny.gov/chemical/8912.html

[42] USEPA *Guideline on Air Dispersion Models*, Appendix W of 40 CFR, Part 51 andDEC's program policy guide DAR10: *NYSDEC Guidelines on Dispersion Modeling Proceduresfor Air Quality Impact Analysis*. See Hhttp://www.dec.ny.gov/chemical/8923.html.

air, which provides for conservative ambient impacts. However, these effects are of minor consequences within the context of plume travel time and downwind distances associated with the maximum ambient impact of pollutants discussed in this section.

AERMOD also does not treat secondary formation of pollutants such as Ozone (O_3) from NO_2 and Volatile Organic Compounds (VOCs), but it can model the non-criteria and toxic pollutant components of gas or VOC emissions in relation to established ambient thresholds. There does not exist a recommended EPA or DEC "single" source modeling scheme to simulate O_3 formation from its precursors. This would involve not only complex chemical reactions in the plumes, but also the interaction of the regional mix of sources and background levels. Such an assessment is limited to regional scale emissions and modeling and is outside the scope of the analysis undertaken herein.

Thus, the AERMOD model was used with a set of emission rates and source parameters, in conjunction with other model input data discussed in the following subsections, to estimate maximum ambient impacts, which are then compared to established Federal and New York State ambient air quality standards (AAQS) and other ambient thresholds. The latter are essentially levels established by DEC's Division of Air Resources (DAR)'s program policy document DAR-143. These levels are the 1 hour SGCs and annual AGCs (short-term and annual guideline concentration, respectively). Where certain data on the chemicals modeled and the corresponding ambient thresholds were missing, New York State Department of Health (DOH) staff provided the requested information. For the thresholds, DEC's Toxics Assessment section then calculated the applicable SGCs and AGCs. The modeling procedures also invoke a number of "default" settings recommended in the AERMOD user's guide and EPA's AERMOD Implementation Guide. For example, the settings of potential wells are not expected to be in "urban" locations, as defined for modeling purposes and, thus, the rural option was used. Other model input data are described next.

Meteorological Data

The AERMOD model requires the use of representative hourly meteorological data, which includes parameters such as wind speed, wind direction, temperature and cloud cover for the calculation of transport and dispersion of the plumes. A complete set of all the parameters needed

[43] See: Hhttp://www.dec.ny.gov/chemical/30560.html

for modeling is generally only available from National Weather Service (NWS) sites. The "raw" data from NWS sites are first pre-processed by the AERMET program and the AERSURFACE software using land use data at the NWS sites, which then create the necessary parameters to be input to AERMOD. There is a discrete set of NWS sites in New York which serves as a source of representative meteorological data sites for a given project. However, for this analysis, the large spatial extent of the Marcellus Shale necessitated the use of a number of the NWS site data in order to cover the meteorological conditions associated with possible well drilling sites throughout the State.

Figure 6.4 presents the spatial extent of the Marcellus Shale and the six NWS sites chosen within this area and deemed adequate for representing meteorological conditions for the purpose of dispersion modeling of potential well sites. It was judged that these sites will adequately envelope the set of conditions which would result in the maximum impacts from the relatively low level or ground level sources identified as sources of air pollutants. In addition, EPA and DEC modeling guidance recommends the use of five years of meteorological data from a site in order to account for year to year variability. For the current analysis, however, the Department has chosen two years of data per site to gauge the sensitivity of the maxima to these data and to limit the number of model calculations to a manageable set. It was determined that impacts from the relatively low level sources would be well represented by the total of 12 years of data used in the analysis.

The NWS sites and the two years of surface meteorological data which were readily available from each site are presented in Table 6.12, along with latitude and longitude coordinates. In addition to these surface sites, upper air data is required as input to the AERMOD model in order to estimate certain meteorological parameters. Upper air data is only available at Buffalo and Albany for the sites chosen for this analysis, and were included in the data base. It should be noted that upper air data is not the driving force relative to the surface data in modeling low level source impacts within close proximity of the sources, as analyzed in this exercise. The meteorological data for each year was used to calculate the maximum impacts per year of data and then the overall maxima were identified from these per the regulatory definitions of the specific AAQS and SGCs/AGCs, as detailed in the subsequent subsection.

Receptor and Terrain Input Data

Ground level impacts are calculated by AERMOD at user defined receptor locations in the area surrounding the source. These receptors are confined to "ambient air" locations to which the public has access. Current DMN regulations define a set of “set back” distances from the well sites to roadways and residences. However, these set back distances (e.g. 25m) are defined from the wellhead for smaller “footprint” vertical wells relative to the size of the multi-pad horizontal wells. Furthermore, EPA’s strict definition of ambient air only excludes areas to which the public is explicitly excluded by enforceable measures such as fences, which might not be normally used by the industry. Thus, in order to determine the potential closest location of receptors to the well site, the modeling has considered receptors at distances as close as the boundary of a 150m by150m well pad. On the other hand, it is clear from diagrams and pictures of sample sites that the public would have no access to within the well pad area. However, the closest receptor to any of the sources was limited to 10 m to allow for a minimum practical “buffer” zone between the equipment on the pad and its edge. The “centralized” impoundment in which the flowback water is to be placed has not been identified with a “set back” distance, except industry has noted that a fence would be erected around the pond. Thus, the closest receptors for this source were placed at 10 meters from the impoundment’s edge which is the closest practical distance at which a fence would need to be placed.

The location of the set of modeled receptors is an iterative process for each application in that an initial set is used to identify the distance to the maximum and other relatively high impacts, and then the grid spacing may need to be refined to assure that the overall maxima are properly identified. For the type of low level and ground level sources which dominate the modeled set in this analysis, it is clear that maximum impacts will occur in close proximity to the sources. Thus, a dense grid of 5m and 10 m spacing was placed along the onsite and offsite impoundment “fences”, respectively, and extended on a Cartesian grid at 10m grid spacing out to 100m from the sources in all directions. In a few cases, the modeling grid was extended to a distance of 1000m at a grid spacing of 25m from the 100m grid’s edge in order to determine the concentration gradients. For the combustion and venting sources, an initial grid at 10 m increment was placed from the edge of the 150m by 150m pad area out to 1000m, but this grid was reduced to a Cartesian grid of 20m from spacing the “fenceline” to 500m in order to reduce computation time. The revised receptor grid resolution was found to adequately resolve the maxima as well for the purpose of demonstrating the anticipated drop off of concentrations beyond these maxima.

The AERMOD model is also capable of accounting for ground level terrain variations in the area of the source by using U.S. Geological Survey Digital Elevation Model (DEM) or more recent

National Elevation Data (NED) sets. However, for sources with low emission release heights, the current modeling exercise was performed assuming a horizontally invariant plane (flat terrain) as a better representation of the impacts for two reasons. First, given the large variety of terrain configurations where wells may be drilled, it was impractical to include a "worst case" or "typical" configuration. More importantly, the maximum impacts from the low level sources are expected to occur close-in to the facility site, and any variations in topography in that area was determined to be best simulated by AERMOD using the concept of "terrain following" plumes.

It should be clarified that this discussion of terrain data use in AERMOD is distinct from the issue of whether a site might be located in a complex terrain setting which might create distinct flow patterns due to terrain channeling or similar conditions. These latter mainly influence the location and magnitude of the longer term impacts and are addressed in this analysis to the extent that the set of meteorological data from six sites included these effects to a large extent. In addition, the air emission scenarios addressed in the modeling for the three operational phases and associated activities are deemed to be more constrained by short-term impacts due to the nature and duration of these operations, as discussed further below. For example, the emissions from any venting or well fracturing are intermittent and are limited to a few hours and days before gas production is initiated.

Emissions Input Data

EPA and DEC guidance require that modeling of short-term and annual impacts be based on corresponding maximum potential and, when available, annual emissions, respectively. However, guidance also requires that certain conservative assumptions be made to assure the identification of maximum expected impacts. For example, the short-term emission rates have to represent the maximum allowable or potential emissions which could be associated with the operations during any given set of hours of the meteorological data set and the corresponding averaging times of the standards. This is to assure that conditions conducive to maximum impacts are properly accounted for in the varying meteorological conditions and complex dependence of the source's plume dispersion on the latter. Thus, for modeling of all short-term impacts (up to 24 hours), the maximum hourly emission rate is used to assure that the meteorological data hours which determination the maximum impacts over a given period of averaging time were properly assessed.

Based on the information and determinations presented in Section 6.5.1.2 on the set of sources and pollutants which need to be modeled, the necessary model input data was generated. This data includes the maximum and annual emission rates for the associated stack parameters for all of the pollutants for each of the activities. In response to the Department's request, industry provided the necessary model input data for all of the activities at the multi-well pad site, as well as at a potential offsite compressor. These data were independently checked and verified by DAR staff and the final set of source data information was supplied in the industry report noted previously. Although limited source data were also contained in the ICF report, the data provided by industry were deemed more complete and could be substantiated for use in the modeling.

The sources of emissions specific to Marcellus shale operations are treated by AERMOD as either point or area sources. Point sources are those with distinct stacks which can also have a plume rise, simulated by the model using the stack temperatures and velocities. An example of a point source is the flare used for the temporary vented gas. Area sources are generally low or ground level sources of distinct spatial dimensions which emit pollutants relatively uniformly over the whole of the area. The flowback water impoundments are a good example of area sources. In addition to the emission rates and parameters supplied by industry, available photographs and diagrams indicated that many of the stacks could experience building downwash effects due to the low stack heights relative to the adjacent structure heights. In these instances, downwash effects were included in a simplified scheme in the AERMOD modeling by using the height and "projected width" of the structure. These effects were modeled to assure worst case impacts for the compressors and engines were properly identified. The specific model input data used is described next, with criteria and non-criteria source configurations presented separately for convenience.

Criteria Pollutant Sources - The emission parameters and rates for the combustion source category at a multi-horizontal well pad were taken from data tables provided in the industry report. In some instances, additional information was gathered and assumptions made for the modeling. The report provides "average" and maximum hourly emission rates, respectively, of the criteria pollutants in Tables 7 and 8 for the drilling operations, Tables 14, 15, 20 and 21 for the completion phase operations, Table 18 for the production phase sources, and Table 24 for the offsite compressor. It should be noted that the criteria pollutant source emissions in these tables are not affected by the dry versus wet gas discussions, with the exception of SO_2 emissions from flaring of H_2S in wet gas. For this particular pollutant, the flare emission rate from Table 21 was used. Furthermore, the modeling has included the off-site compressor in lieu of the smaller onsite compressor at the wellhead and an onsite line heater instead of an offsite one in order to determine expected worst case operations impacts.

As discussed previously, initial modeling of both short-term and annual impacts were based on the maximum hourly emissions rates, with further analysis of annual impacts performed using more representative long term emissions only when necessary to demonstrate compliance with corresponding annual ambient thresholds. For the short-term impacts (less than 24 hour), it was assumed that there could be simultaneous operations of the set of equipment at an on-site pad area for one well drilling, one well completion, and one well flaring, along with operations of the onsite line heater and off site compressor for the gas production phase for previous completed wells. It should be clarified that although AERMOD currently does not include the flare source option in the SCREEN3 model, the heat release rate provided in Table 15 of the industry report was used to calculate the minimum flare "flame height" as the stack height for input to AERMOD.

The placement of the various pieces of equipment in Table 6.11 on a well pad site was chosen such as not to underestimate maximum offsite as well as combined impacts. For example, the schematic diagram in the ICF report represents a typical set up of the various equipment, but for the modeling of the sources which could be configured in a variety of ways on a given pad, the locations of the specific equipment were configured on a well pad without limiting their potential location being close to the property edge. That is, receptors were placed at distances from the sources as if these were near the edge of the property, with the "buffer zone" restriction noted previously. This was necessary since many of these low level sources could have maximum impacts within the potential 150m distance to the facility property and receptors could not be eliminated in this area.

At the same time, however, it would be unrealistic to locate all of the equipment or a set of the same multi-set equipment at an identical location. That is, certain sources such as the flare are not expected to be located next to the rig and the associated engines due to safety reasons. In addition, there are limits to the size of the "portable" engines which are truck-mounted, thus requiring a set of up to 15 engines placed adjacent to each other rather than treating these as a single emission point. Since there were some variations in the number and type of the multi-source engines and compressors specifically used for drilling and completion, a balance was reached between using a single representative source, with the corresponding stack parameters and total emissions, versus using distinct individual source in the multi set. This determination was also dictated by the relative emissions of each source.

The modeling used a single source representation for the drilling engines and compressors from Table 8, while for the fracturing pump engines, five sources were placed next to each other to represent three-each of the potential fifteen noted in Table 15 of the industry report. The total emission rates for the latter sources were divided over the five representative sources in proper quantities. The rest of the sources are expected to either be a single equipment or are in sets such that representation as a single source was deemed adequate. Using sample photographs from existing operations in other states, estimates of both the location as well as the separation between sources were determined. For example, the size of the trucks with mounted frack engines was used to determine the separation between a row of the five representative sources. These photographs were also used to estimate the dimension of the “structures” which could influence the stack plumes by building downwash effects. All of the sources were deemed to have a potential for downwash effects, except for the flare/vent stack. The height and “effective” horizontal width of the structure associated with each piece of equipment were used in the modeling for downwash calculations.

It was also noted from the photographs that two distinct types of compressors are used for the drilling operations, with one of the types having “rain-capped” stacks. This configuration could further retard the momentum plume rise out of the stack. Thus, for conservatism, this particular source was modeled using the “capped” stack option in AERMOD with the recommended low value for exit velocity. Furthermore, since the off-site “centralized” compressor could conceivably be located adjacent to one of the multi-well pads, this source was located adjacent to, but on the other side of the edge of the 150m by 150m pad site.

The placement of the various sources of criteria pollutants in the modeling is represented in Figure 6.5. This configuration was deemed adequate for the determination of expected worst case impacts from a ‘typical” multi-well pad site. Although the figure outlines the boundary of the 150m by 150m typical well pad area, it is again clarified that receptors were placed such that each source would have close-in receptors beyond the 10 m “buffer” distance determined necessary from a practical standpoint. That is, receptors were placed in the pad area to assure simulation of any configuration of these sources on the pad at a given site.

Annual impacts were initially calculated using the maximum hourly emission rates, and the results reviewed to determine if any thresholds were exceeded. If impacts exceeded the annual threshold for a given pollutant, the "average" emission rates specifically for the drilling engines/compressors in Table 7 and for the hydraulic fracturing and flaring operations from Table 20 of the industry report were used. For the other sources, such as the line-heater and offsite compressor, the average and maximum rates are the same as presented in Tables 18 and 24, respectively, and were not modified for the refined annual impacts. As these average rates account only for the variability of "source demand" for the specific duration of the individual operations, an additional adjustment needed to be made for the number of days in a year during which up to 10 such well operations would occur. Thus, from Tables 7 and 14, it is seen that there would be a maximum of 250 days of operations for the drilling engines, maximum of 20 days for hydraulic fracturing engines, and maximum of 30 days of flaring in a given year. Thus, for these sources, the annual average rate was adjusted accordingly. On the other hand, there are no such restrictions on the use of the line heater and off-site compressor for the production phase and the annual emissions were represented by the maximum rates. Some of these considerations are further discussed in the resultant impact section.

Lastly, in order to account for the possibility of well operations at nearby pads at the same time as operations at the modeled well pad configuration, a sensitivity analysis was performed to determine the potential contribution of an adjacent pad to the modeled impacts. This assessment addressed, in a simplified manner, the issue of the potential for cumulative effects from a nearby pad on the total concentrations of the modeled pad such that larger "background levels" for the determination of compliance with ambient threshold needed to be determined. The nearby pad with identical equipment and emissions as the pad modeled was located at a distance of one kilometer (km) from the 150m by 150m area of the modeled pad. This separation distance is the minimum expected for horizontal wells drilled from a single pad, which extends out to a rectangular area of 2500m by 1000m (one square mile).

Non-Criteria Pollutant Sources - There are a set of pollutants from three "distinct" sources in the Marcellus shale operations for which there are no national ambient standards, but for which New York State has established either a state standard (H_2S) or toxic guideline concentrations. These are VOC species and HAPs which are emitted from: a) sources associated with venting of gas prior to the production phase, b) as by-products of combustion of gas or fuel oil, and c) the additives which exist in flowback water impoundments. A review of the data on these pollutants and their sources indicated that the three distinct source types can be modeled independently, as described below.

First, of the sources which vent the constituents of the "wet" gas (if it is encountered), the flowback venting has by far the most dominant emissions of the toxic constituents. The other two sources of gas venting are the mud-gas separator and the dehydrator, and a comparison of the relative emissions of the five pollutants identified in the industry report (benzene, hexane, toluene, xylene, and H_2S) from these three sources in Tables 8, 21 and 22 shows that the flowback venting has about two orders of magnitude higher emissions than the other two sources. As noted in the industry report, this venting is limited to a few hours before the flare is used, which reduces these emissions by over 90%. Thus, modeling was used to determine the short-term impacts of the venting emissions. Annual impacts were not modeled, due to the very limited time frame for gas venting, even if ten wells are to be drilled at a pad.

It was determined that during these venting events, essentially no other emissions of the same five toxics would occur from other sources. That is, even though a subset of these pollutants are also tabulated in the industry report at relatively low emissions for the engines, compressors and the flares, it is either not possible or highly unlikely that the latter sources would be operating simultaneously with the venting sources (e.g. gas is either vented or flared from the same stack). Thus, for the short-term venting scenario, only the impacts from the three sources need to be considered. It was also determined that rather than modeling each of the five pollutant for the set of the venting sources for each of the twelve meteorological years, the flowback venting source parameters of Table 15 were used with a unitized emission rate of 1 g/s as representative of all three sources. The actual pollutant specific impacts were then scaled with the total emissions from all three sources. This is an appropriate approximation, not only due to the dominance of the flowback vent emissions, but also since the stack height and the calculated plume heights for these sources are very similar. This simplification significantly reduced the number of model runs which would otherwise be necessary, without any real consequence to the identification of the maximum short-term impacts.

The next set of non-criteria pollutants modeled included those resulting from the combustion sources. It should be clarified that pollutants emitted from the glycol dehydrator (e.g. benzene), which are associated with combustion sources were also included in these model calculations for both the short-term and annual impacts. A review of the emissions in Tables 8, 18, 21, and 24 indicates seven toxic pollutants with no clear dominance of a particular source category. Furthermore, the sources associated with these pollutants have much more variability in the source heights than for the venting scenario. For example, the flare emissions of the three pollutants in Table 21 are higher than for the corresponding frac pump engines, but the plume from the flame is calculated to be at a much higher level than those for the engines or compressors such that a "representative" source could not be simply determined in order to be able to model a unitized emission rate and limit the number of model runs.

However, it was still possible to reduce the number of model calculations from another standpoint. The seven pollutants associated with these sources were ranked according to the ratios of their emissions to the corresponding 1 hour SGCs and AGCs (SGCs for hexane and propylene were determined by Toxics Assessment section since these are not in DAR-1 tables). These ratios allowed the use of any clearly dominant pollutants which could be used as surrogates to identify either a potential issue or compliance for the whole set of toxics. These calculations indicated that benzene and formaldehyde are clearly the two pollutants which would provide the desired level of scrutiny of all of the rest of the pollutants in the set. To demonstrate the appropriateness of this step, limited additional modeling for the annual impacts for acetaldehyde was also performed due to the relatively low AGC for this pollutant. These steps further reduced the number of model runs by a significant number.

The emission parameters, downwash structure dimension and the location of the sources were the same as for the criteria pollutant modeling. Similar to the case of the criteria pollutants, any necessary adjustments to the annual emission rates to provide more realistic annual impacts were made after the results of the initial modeling were reviewed to determine the potential for adverse impacts. These considerations are further discussed in the resultant impact section.

The last set of non-criteria pollutant modeling dealt with the set of chemicals added to the hydraulic fracturing water during the completion phase of operations. For the potential emissions and impacts of these various additives which could end up in the flow back impoundments, a different approach had to be taken. As noted previously, according to ICF report and industry, no air emissions were provided since they believed these air emissions to be negligible due to the extremely low concentrations of these chemicals in the flowback water. However, both theory and practice indicate that atmospheric transfer of chemicals in water impoundments clearly occurs, albeit at low concentrations, and it is only prudent to quantify these emissions in order to explicitly determine the consequent impacts.

The Department has performed a limited, yet representative, analysis of the air impacts of the various chemicals identified in the additives to the hydraulic fracturing water. The purpose of the Department's analysis is to use a selected set of chemicals from a large list proposed for use by industry to determine whether there is a potential for any adverse effects from their release into the atmosphere and, if so, what mitigation measures might be necessary. To date, industry has identified a large number of compounds which serve various purposes during the hydraulic fracturing process that might be used in well completion operations. In addition, industry has supplied DEC with compound specific chemical compositions (including "inert" additives) and their percentages which make up these compounds. These latter "additives" essentially fall into one of the categories identified with a "purpose", as depicted in Figure 6.6, which is a typical percent-by-weight representation of the fracturing water/proppant/additive mix provided by Chesapeake Energy. There are likely certain variations in these percentages within the industry and specific operations, but these are deemed relatively small within the context of the modeling and the conservative steps taken to estimate emissions. In addition, these have been checked against certain actual data used, as described below. The specific purpose of the additives is described in Chapter 5.

It is seen that these various compounds make up about 1% of the overall water, proppant (e.g. sand) and the additives mix, but these could, nonetheless, contain chemicals with very low ambient concentration thresholds of concern. The first criterion in choosing the chemicals to model was to assure that each of these additives was represented. Since there was a large number of proposed products for each category of additive and these, in turn, have even a larger set of specific chemical components within each product, a set of additional criteria was needed to identify the practical set to be modeled. To assure that the purpose of the Department's modeling exercise was achieved (i.e. that of identifying if any potential for adverse effects could occur), the following criteria were also used to further assure additive representation:

1) The pollutant has a relatively low ambient threshold and, thus, is of potential exposure concern. To that end, a list was provided by NYSDOH staff of specific pollutants which had water and air “high” risk concerns. These included Amides, VOC species, and glycols. In addition, DEC’s Air Guide-1 tables of SGCs and AGCs we referenced to identify pollutants with low ambient threshold values.

2) The chemical had to have an established threshold or one for which it could be relatively easily established in order for the modeled concentrations to be compared to a concern level. It should be noted that, although the majority of the chemicals had SGCs or AGCs listed, a considerable number did not.

3) The chemical with the lower ambient threshold was used as representative of that class of additives if the amounts to be used were essentially the same or when the “quantity” factor was more than balanced by the “low threshold” factor. Examples were the bactericide glutaraldehye, which has rather low SGCs and AGCs, and methanol, with lower SGC and AGC than another surfactant, such as isopropanol.

4) The specific chemical appeared frequently or was a component of more than one additive. For example, ethylene glycol was listed as a component of iron and clay inhibitor, crosslinker and scale inhibitor.

5) Certain chemicals with small amounts (<5%) in the compounds, were still considered if these were known high toxicity pollutant of concern; for example benzene and formaldehyde.

Using the above criteria, the list of the representative chemicals in Table 6.13 was generated. Although this is not a complete list of the very large set of chemicals in the compounds, DAR believes these are adequate for the current modeling purposes. It is important to note, however, that a few compounds identified in the final submission from industry included certain pollutants with higher toxicity concerns (e.g. benzene and xylene) and at much larger quantities than identified previously. There were a handful of such entries and these were associated specifically with either “solvents” or “surfactants”. Since the former does not show up in Figure 6.6, DMN staff contacted industry and industry representatives clarified that these solvents were included in the list to be comprehensive, but would not be used (in addition to a set of other solvents) for “slickwater” hydraulic fracturing in the Marcellus Shale in New York. In addition, the specific surfactant with the benzene content will also not be used in New York. Thus, it will be necessary to either omit these compounds from the list to be used in New York or require further site specific analysis for a given multi-pad area to address consequent impacts. Given that there was only one remaining entry with benzene at minute percentages, as noted below, the implication is that this chemical should not be used in any additive for hydraulic fracturing water mix in New York.

Table 6.13 gives the purpose for which the chemical appears in a compound as noted in Figure 6.6, with some chemicals noted to be used for multiple purposes. The "percent of the agent" data is also taken from Figure 6.6, with two modifications. First, for chemicals which appear in different agents and which could be found simultaneously in the hydraulic fracturing water, an attempt was made to account for the larger quantity of the chemical in the total mix. For example, ethylene glycol is noted to be used in four agents and the percentages of these agents from Figure 6.6 were added to the extent that this chemical was found to essentially have the same "amount" as percentage in compounds in all of these agents. The second modification relates to the bactericides. In an attempt to check the consistency of the percentages in Figure 6.6 with available actual data from industry on the fracturing water/additive mixes from Marcellus wells in Pennsylvania and West Virginia, it was noted that the percentages of the various agents verified well, except for the bactericides. For the latter, the data consistently showed much higher percentages; in the range of 0.02 to 0.03% versus the 0.001% in Figure 6.6. Thus, a conservative value of 0.03% was used in the Department's calculations.

Table 6.13 also lists the maximum percentage of the chemicals noted from all of its entries in the data provided by industry. In most instances there was fairly small variation in these percentages, but in entries with larger variations, the maximum percent of chemical in the compound was used. In a few cases there were only one or two entries. For example, benzene was listed only at 0.0001 % in one compound, keeping in mind the caveat noted previously on compounds not to be used for the subject well completions.

Multiplying the data in columns 4 and 5 (in fractions) and unit conversions gives the maximum concentration of the specific chemical in column 6 of Table 6.13. These data are then used in the emissions calculations. The last two columns in Table 6.13 provide the 1 hour SGC and annual AGC values used to compare the resultant impacts. It is noted that four of the chemicals did not have a SGC or AGC tabulated in the Department's DAR-1 tables. For these, the noted values were developed by DAR's Toxics Assessment Section with assistance from NYSDOH.

To calculate emission rates of these chemicals, the Department has relied upon an EPA document44 on emissions from water treatment facilities which provide such methods for surface impoundments. These emissions can be used in the Department's modeling analysis for the two different impoundment sizes. The document provides a set of equations for different source categories, and the Department has relied upon the equations in Section 5 for surface impoundments to calculate emissions. In particular, the equation in Section 5.2 for quiescent water emissions is used, including total gas and liquid phase transfer coefficients, with the concentration of the pollutant in the water and the surface area of the impoundments as inputs. The model is based on the concept that the transfer of these "impurities" from the water to the atmosphere is dependent upon the rate at which atmospheric and chemical/physical properties of these chemicals affect the release into the air. These latter parameters are, in turn, dependent mainly on factors such as wind speed and the gas and liquid phase solubility and mobility in water of the chemicals. For example, the more soluble a chemical is in water, the less of it is available to transfer to the air, while the higher the wind speed, the more the chemical will experience a transfer out of the water due to the "friction effects" of the wind. In addition to these transfer coefficients, the emission is linearly related to the concentration of the chemical in the water.

In order to calculate the gas phase transfer, the partitioning coefficient is determined from a simplified equation which only requires Henry's law constant (H). These latter are tabulated in Appendix C of the EPA report for many compounds. For the compounds which the Department has chosen to analyze in its modeling and for which H values are not given in the report, the Department has obtained appropriate values with assistance from NYSDOH staff. It should be noted that these values are representative of standard conditions and no attempt is made to account for any dependency on factors such as temperature. This is deemed more than adequate for the Department's purposes.

In addition, both the gas and liquid phase transfer coefficient equations in Table 5-1 of the EPA report require values of air and water diffusivities which were also obtained either from Appendix C or provided by NYSDOH staff. Limited NYSDOH data reflected more recent experimental values. These transfer coefficient equations also require the length, "diameter" and depth of the impoundments and the Department has used, respectively, values of the longer length, an equivalent diameter calculated from the areas, and a depth of about three meters(as provided by industry). These result in values of fetch/depth of 50 and 15 and effective diameter of 170m and 30m for the off-site and onsite impoundments, respectively, as inputs to the appropriate equations.

Both the liquid and gas phase transfer coefficients are dependent on wind speed, with the former being more sensitive to this parameter. For both practical and theoretical reasons, the Department has not attempted to vary these coefficients with the wind speed data used in the meteorological data bases. Instead, the Department has used a constant "average" wind speed based on the consideration of the expected high impacts and the Springer, et al formulations in Table 5-1 for the liquid phase. First, there are different formulations for wind speeds above or below 3.25m/s, with no real dependence of the liquid phase coefficient on wind speeds below this value. In addition, it is commonplace that the highest impacts from ground level sources are associated with lower wind speeds. Since the transfer coefficient (and emission rate) is directly related to wind speed, while the ambient concentration for ground level sources is inversely related to wind speed, the Department has chosen the 3.25 m/s value as a balance between these two effects. Although annual average wind speeds at many sites are at or above 5m/s, the lower choice of average wind speed assures that the Department has estimated realistic, yet still conservative values of emissions associated with the conditions of higher expected impact.

With these calculated parameters, emission estimates are made for the two impoundments using their corresponding areas and the concentration of each chemical determined from the percent of the chemical in the flowback water. These latter values are simply the product of the percent in compound and the percent of the compound in water (in fractions) noted in Table 6.13.The use of these concentrations is deemed conservative to a certain extent since industry has noted that there is additional mixing with in-ground water as well as certain removal of the chemicals during hydraulic fracturing. However, these effects cannot be easily quantified and are likely balanced by other factors which could result in higher emissions. A limited number of chemical samples of flowback water made available to DEC do not contain or were not analyzed for a majority of the compounds the Department has modeled and, thus, "actual" data could not be used to verify the emissions. Even if such data were available, issues would still need to be resolved with adequacy of data samples and representativeness of these samples for Marcellus shale drilling in New York.

The calculated emissions were then used to predict maximum 1 hour and annual impacts from the two impoundments. However, unlike combustion and venting source scenarios discussed above, the annual impacts were not adjusted for any operational restrictions, especially for the "centralized" impoundment since some of the industry has indicated a desire to keep these open for up to three years. There is, however, little specific information on the potential reuse of the flowback water which can then be incorporated in the determination of more realistic annual emissions. Thus, it is likely that annual emissions could be somewhat overstated in the modeling, but given the lack of any limitation of the operational restrictions on the flowback water, the modeling had to be performed for the worst case scenario of emissions occurring for a full year. Some consideration is given to pollutant-specific emission rates on an annual basis in the discussions of the resultant impacts.

Pollutant Averaging Times, Ambient Thresholds and Background Levels

The AERMOD model calculates impacts for each of the hours in the meteorological data base at each receptor and then averages these values for each averaging time associated with the ambient standards and thresholds for the pollutants. For example, particulate matter (PM10 and PM2.5) has both 24-hour and annual standards, so the model will present the maximum impact at each receptor for these averaging times. As the form of the standards cannot be exceeded at any receptor around the source, the model also calculates and identifies the overall maximum impacts over the whole set of receptors.

For the set of pollutants modeled, the averaging times of the standards are: for S02- 3hour, 24 hour, and annual; for PM10/PM2.5-24 hour and annual; for NO_2-annual; for CO-1 hour and 8 hour; and for the set of toxic pollutants- 1hour SGCs and annual AGCs. For most criteria pollutants, the annual standards are defined as the maxima not to be exceeded at any receptor, while the short-term standards are defined at the highest-second-highest (HSH) level wherein one excedence is allowed per receptor. The exception is PM2.5 where the standards are defined as the 3 year averages, with the 24 hour calculated at the 98th percentile level. The toxic pollutant SGCs and AGCs are defined at a level not be exceeded. In the Department's assessments, the maximum impacts for all averaging times were used for all pollutants, except for PM2.5, in keeping with modeling guidance for cases where less than five years of meteorological data per site is used.

In addition to the standards, EPA has defined levels which new sources or modifications after a certain time frame cannot exceed and cause significant deterioration in air quality in areas where the observations indicate that the standards are being met (known as attainment areas). The area depicted in Figure 6.4 for the Marcellus Shale has been classified as attainment for all of the pollutants modeled in the Department's analysis. Details on area designations and the state's obligation to bring a nonattainment area into compliance are available at DEC's public webpage as well as from EPA's webpage45. For the attainment areas, EPA's Prevention of Significant

[45] See: Hhttp://www.dec.ny.gov/chemical/8403.htmlH and Hhttp://www.epa.gov/ttn/naaqs/.

Deterioration (PSD) regulations currently define increments for SO_2, NO_2 and PM10. Although, in the main, the PSD regulations apply only to major sources, the increments are consumed by both major and minor sources and must be modeled to assure compliance. However, the PSD regulations also exempt "temporary" sources from having to analyze for these increments. It is judged that essentially all of the emissions at the well pad (which are individually defined as a "source" for applicability purposes) can be qualified as such since the expectation is that the maximum number of wells at a pad can be drilled and completed within a year. Even if partial set of the wells is drilled in a year and these operations cease, the increment would be "expanded" as allowed by the regulations.

The only exception to the temporary designation would be the offsite compressor and the line heater which can operate for years. Thus, only these two sources were considered in the increment consumption analysis. The applicable standards and PSD increments are presented in Table 6.14 for the various averaging times. In addition to these standards and increments, the table provides EPA's defined set of Significant Impact Levels (SILs) which exist for most of the criteria pollutants. These SILs are at about 2 to 4 percent of the corresponding standards and are used to determine if a project will have a "significant contribution" to either an existing adverse condition or will cause a standards violation.

These SILs are also used to determine whether the consideration of background levels, which include the contribution of regional levels and local sources, need to be explicitly addressed or modeled. When the SILs are exceeded, it is necessary to explicitly model nearby major sources in order to establish potential "hot spots" of exceedences to which the project might contribute significantly. For the present analysis, if the SILs are exceeded for the single multi-well pad, the Department has considered the potential for the contribution of nearby pads to the impacts of the former on a simplified level. The approach used was noted previously and involves the modeling of a nearby pad placed at 1000m distance from the pad for which detailed impacts were calculated, in order to determine the relative contribution of the nearby pad sources. If these results indicate the potential for significant cumulative effects, then further analysis would need to be performed.

On the other hand, in order to determine existing criteria pollutant regional background levels, which must be explicitly included in the calculation of total concentrations for comparison to the standards, the Department has conservatively used the maximum observations from a set of DEC monitoring sites in the Marcellus Shale region depicted in Figure 6.4. The location of these sites and the corresponding data is available in the DEC public webpage.46 The Department has reviewed the data from these sites to determine representative, but worst case background levels for each pollutant. The Department has used maximum values over a three year period from the latest readily available tabulated information from 2005 through 2007 from at least two sites per pollutant within the Marcellus shale area, with two exceptions. First, in choosing these sites, the Department did not use "urban" locations, which could be overly conservative of the general areas of well drilling. This meant that for NO_2 and CO, data from Amherst and Loudonville, respectively, were used as representative of rural areas since the rest of the DEC monitor sites were all in urban areas for these two pollutants. Second, data for PM10 for the period chosen was not available from any of the appropriate sites due to switching of these sites to PM2.5 monitoring per EPA requirements. Thus, the Department relied on data from 2002-04 from Newburgh and Belleayre monitors. The final set of data used for background purposes are presented in Table 6.15. These data represent worst case estimates of existing conditions to which the multi-well pad impacts will be added in order to determine total concentrations for comparison to the AAQS. In instances where the use of these maxima causes an exceedence of the AAQS, EPA and DEC guidance identify procedures to define more case specific background levels. Per DEC Air Guide-1, since there are no monitoredbackground levels for the non-criteria pollutants modeled, the impacts of H_2S and rest of the toxic chemicals are treated as incremental source impacts relative to the corresponding standard and SGCs/AGCs, respectively. Determinations on the acceptability of these incremental impacts are then made in accord with the procedures in Air Guide-1.

6.5.2.4 Results of the Modeling Analysis

Using the various model input data described previously, a number of model calculations were performed for the criteria and toxic pollutants resulting from the distinct operations of the onsite and offsite sources. Each of the meteorological data years were used in these assessments and the receptors grids were defined such as to identify the maxima from the different sources. In some instances, it was possible to limit the number of years of data used in the modeling, as results from a subset indicated impacts well below any thresholds. In other cases, it was necessary to expand

[46] See: Hhttp://www.dec.ny.gov/chemical/8406.html

the receptor grid such that the decrease in concentration with downwind distance could be determined. These two aspects are described below in the specific cases in which they were used.

As described in the previous section, initial modeling of annual impacts was performed in the same model runs as for the short-term impacts, using the maximum emission rates. However, in a number of cases, this approach lead to exceedences of annual thresholds and, thus, more appropriate annual emissions were determined in accord with the procedures described in Section 6.5.2.3, and the annual impacts were remodeled for all of the data years. These instances are also described below in the specific cases in which the annual emissions were used. The results from these model runs were then summarized in terms of maxima and compared to the corresponding SILs, PSD increments, ambient standards, and Air Guide-1 AGCs/SGCs.

This comparison indicated that, using the emissions and stack parameter information provided in the industry report, a few of the ambient thresholds could be exceeded. Certain of these exceedences were associated with conditions (such as very low stacks and downwash effects) which could be rectified relatively easily. Thus, some additional model runs were performed to determine conditions under which the ambient thresholds would be met. These results are presented below with the understanding that industry could implement these or propose their own measures in order to mitigate the exceedences. Results for the criteria pollutants are discussed first, followed by the results for the toxic/non-criteria pollutants.

Criteria Pollutant Impacts

The set of sources identified in Table 6.11 for short-term simultaneous operations of the various combustion sources with criteria pollutant emissions were initially modeled with the maximum hourly emission rate and one year of meteorological data. It was clear from these results that the annual impacts for PM and NO_2 had to be recalculated using the more appropriate annual emissions procedures discussed in Section 6.5.2.3. That is, for these pollutants, the "average" rates in the industry report were scaled by the number of days/hours of operations per year for the drilling engine/compressor, the hydraulic fracturing engines and the flare, and then these results were multiplied by ten to account for the potential of ten wells being drilled at a pad for a year. The rest of the sources were modeled assuming full year operations at the maximum rates. In addition, based in part on the initial modeling, two further adjustments were made to the annual NO_2 impacts. First, the model resultant impacts were multiplied by the 0.75 default factor of the tier 2 screening approach in EPA's modeling guidelines. This factor accounts for the fact that a large part of emissions of NOx from combustion sources are not in the NO_2 form of the standard. The second adjustment related to the stack height of the off-site compressor, which was raised to 7.6m (25ft) based on the results for the non-criteria pollutants discussed below; that is, this height was deemed necessary in order to meet the formaldehyde AGC.

Each of the meteorological data years was used to determine the maximum impacts for all of the criteria pollutants and the corresponding averaging times of the standards. However, in the case of 24 hour particulate impacts, modeling was limited to the initial year (Albany, 2007) for reasons discussed below. The results for each year modeled are presented in Table 6.16. It should be noted that the SO_2 annual impacts in this table are based on the maximum hourly rates and are very conservative. In addition, the tabulated values for the 24-hour PM2.5 impacts are the eight highest in a year, which is used as a surrogate for the three year average of the eight highest value (i.e., 99^{th} percentile form of the standard). It is seen that the short-term impacts do not show any significant variability over the twelve years modeled.

The overall maxima for each pollutant and averaging time from Table 6.16 are then transferred to Table 6.17 for comparison to the set of ambient thresholds. These maximum impacts are to be added to the worst case background levels from Table 6.15 (repeated in Table 6.17), with the sum presented in the total concentration column. The impacts of only the compressor and the line heater are also presented separately in Table 6.17 for comparison to the corresponding PSD increments. It should be noted that, due to the low impacts for many of the pollutants from all of the sources relative to the increments, only the 24-hour PM10 and annual NO_2 were recalculated for the compressor and line heater, as noted in Table 6.17. The rest of the impacts are the same as those in the maximum overall impact column. The results indicate that all of the ambient standards and PSD increments will be met by the multiple well drilling activities at a single pad, with the exception of the 24 hour PM10 and PM2.5 impacts. In fact, the 3 hour (and very likely the annual) SO_2 impacts are below the corresponding significant impact levels. This is a direct result of the use of the ultra low sulfur fuel assumed for the engines, which will have to be implemented in these operations. In addition, the level of compliance with standards for the maximum annual impacts for NO_2 and PM2.5 are such as to require the implementation of the minimum 7.6m (30ft) stack height for the compressor and general adherence to the annual operational restrictions identified in the industry report.

Table 6.16 results for 24 hour PM10 and PM2.5 impacts were limited to one year of meteorological data since these were found to be significantly above the corresponding standards, as indicated in Table 6.17. Unlike other cases, a simple adjustment to the stack height did not resolve these exceedences and it was determined that specific mitigation measures will need to be identified by industry. However, the Department has determined one simple set of conditions under which impacts can be resolved. It was noted that the relatively large PM10/PM2.5 impacts occurred very close to the hydraulic fracturing engines (and at lower levels near the rig engines) at a distance of 20m, but there was also a very sharp drop-off of these concentration with distance away from these sources. Specifically, to meet the standards minus the background levels in Table 6.17, it was determined that the receptor distance had to be beyond 80m for PM10, and 500m for PM2.5. The latter distance can be lowered in recognition of the fact that the background levels used for these calculations are worst case and can be adjusted using EPA procedures.

In an attempt to determine if a stack height adjustment in combination with a distance limitation for public access approach can alleviate the exceedences, the rig engine and fracturing engine stacks heights were both extended by 3.1m (10ft). From the photographs of the truck-mounted engines, it was not clear if any extensions would be practical and, thus, only this minimal increase was considered. This scenario was modeled again with the Albany 2007 meteorological data. The resultant maximum impacts were reduced to 171 and 104 µg/m3 for PM10 and PM2.5, respectively. For this case, in order to achieve the standards using Table 6.17 background levels, the receptors must be beyond 40m and 500m for PM10 and PM2.5, respectively. Thus, the stack height extension did not significantly affect the concentrations at the farther distances, as would be expected from the fact that building downwash effects are largest near the source. However, the background level for PM2.5 can be adjusted from the standpoint that the expected averages associated with these operations at relatively remote areas are better represented by the regional component due to transport. If the contribution of the latter to the observed maxima is conservatively assumed to be half of the value in Table 6.17 (i.e., 15 µg/m3), then the receptor distance at which a demonstration of compliance can be made is approximately 150m. This seems to be a more practical location at which a fence or a similar measure can be imposed in order to preclude public exposure.

Thus, one practical mitigation measure to alleviate the PM10 and PM2.5 standard exceedences is to raise the stacks on the rig and hydraulic fracturing engines and/or erect a fence at a distance surrounding the pad area in order to preclude public access. Without further modifications to the industry stack heights, a fence out to 500m would be required, but this distance could be reduced to 150m with the taller stacks and a redefinition of the background levels. Alternately, there is likely control equipment which could significantly reduce particulate emissions. The set of specific control or mitigation measures will need to be addressed by industry.

An additional issue addressed in a simplified manner was the possibility of simultaneous operations at a nearby pad, which could be located at a minimum distance of one km from the one modeled, as described previously. It is highly unlikely than more than one additional pad would be operating as modeled simultaneously with other pads within this distance; it is more likely that drill rigs and other heavy equipment will be moved from one pad to another within a given vicinity, with sequenced operations. Regardless, the impacts of all the pollutants and averaging times were determined at a distance of 500m from the modeled well pad for the years corresponding to the maximum impacts. This is half the distance to the nearest possible pad and allows the determination of potential "overlap" in impacts from the two pads. The concentrations at 500m drop off sharply from the maxima to below significance levels for almost all cases such that nearby pad emissions would not significantly contribute to the impacts from the modeled source. These impacts at 500m are presented in the last row of Table 6.16 and their comparisons to the corresponding SILs in Table 6.17 show only the 24-hour PM2.5 and annual NO_2 impacts are still significant at this distance.

Thus, there is a potential that for these two cases the nearby pad operations could contribute to another well operation's impacts. This scenario was assessed by placing an identical set of sources at another pad at a distance of 1km from the one modeled in the general upwind direction from the latter. Impacts were then recalculated on the same receptor grid using the years of modeled worst case impacts for these two pollutants and averaging times. The results indicated that the maximum impacts presented in Table 6.17 for annual NO_2 and 24 hour PM2.5 were essentially the same; in fact the 24 hour PM2.5 impacts are identical to the previous maxima while the NO_2 annual impact of 63.2 increased by only 1.2 µg/m3. Annual Impacts from any other pad not in the predominant wind direction would be lower. These results are judged not to effect the compliance demonstrations discussed above. Thus, it is concluded that minimal interactions from nearby pad well drilling operations would result, even if there were to be such simultaneous operations.

Therefore, compliance with standard and increments can be adequately demonstrated on individual pad basis.

Non-Criteria Pollutant Impacts.

As discussed in Section 6.5.2.3, three "distinct" source types were independently modeled for a corresponding set of toxic pollutants: i) short-term venting of gas constituents, ii) combustion by-products, plus the emissions of the same pollutants from the glycol dehydrator, and iii) a set of representative chemicals from the flowback impoundments. These impacts were determined for comparison to both the short-term 1 hour SGC and annual AGC, with the exception of the venting scenario which was limited to the short-term impacts due to the very short time frame of the practice. The gas venting emissions out of three sources (mud-gas separator, flowback venting, and the dehydrator) are essentially determined by the flowback phase. It was thus possible to model only this source with a unitized emission rate (1g/s) and then actual 1 hour impacts were scaled using the total maximum emission rates.

Each year of meteorological data was modeled with the flowback vent parameters to determine the maximum 1 hour impacts for 1 g/s emission rate. These results were then reviewed and the maximum overall normalized impact of 641 µg/m3 (for Albany, 2008 data) was calculated as the worst case hourly impact. Using the total emissions from all three sources for each of the vented toxic pollutants, as presented in Table 6.18, along with this maximum normalized impact, results in the maximum 1 hour pollutant specific values in the third column of Table 6.18. The pollutants "shaded out" in the table are not vented from these sources. It is seen that all of the worst case 1 hour impacts are well below the corresponding SGCs, but the maximum 1 hour impact of 61.5 µg/m3 for H_2S (underlined top entry in the box) is above the New York standard of 14 µg/m3.

Thus, if any "wet" gas is encountered in the Marcellus Shale, there will be a potential of exceedence of the H_2S standard. The maximum one hour impact occurred relatively close to the stack, and, in order to alleviate the exceedence, ambient air receptors must be excluded in all areas within at least 100m of the stack. Alternately, it is possible to also reduce this impact by using a stack height which is higher than the conservative 3.7m (12ft) height provided in the industry report. Iterative calculations for the year with the maximum normalized impact indicated that a minimum stack height of 9.1m (3 0ft) would be necessary to reduce the impact to the 12.1 µg/m3 value for H_2S reported in the "Max 1 hour" column of Table 6.18. With this requirement, all venting source impacts will be below the corresponding SGCs and standard.

For the set of seven pollutants resulting from the combustion sources and the dehydrator, it was previously argued that it was only necessary to explicitly model benzene and formaldehyde, along with the annual acetaldehyde impacts, in order to demonstrate compliance with all SGCs and AGCs for the rest of the pollutants. The relative levels of the SGCs and AGCs presented in Table 6.18 for these pollutants and the corresponding emissions in the industry report tables clearly show the adequacy of this assertion. For the modeling of these pollutants, the maximum short-term emissions were used for the 1 hour impacts, but the annual emissions were used for the AGCs comparisons. The annual emissions were determined using the same procedures as discussed above for the criteria pollutants.

An initial year of meteorological data which corresponded to the worst case conditions for the criteria pollutants was used to determine the level of these impacts relative to the SGCs and AGCs before additional calculations were made. The results of this initial model run are presented in right hand set of columns of Table 6.18. These indicate that, while the 1-hour impacts are an order of magnitude below the benzene and formaldehyde SGCs and the acetaldehyde AGC, there were exceedences of the AGCs for the former two pollutants (the top underlined entries for each pollutant in the maximum annual column). It was determined that these exceedences were each associated with a particular source: the glycol dehydrator for benzene and the offsite compressor for formaldehyde. It should be noted that these exceedences occur even when the emissions from dehydrator are controlled to be below the National Emissions Standard for Hazardous Air Pollutants (NESHAP) imposed emission rate provided in Table 22 of the industry report and with 90% reduction in formaldehyde emissions accounted for by the installation of an oxidation catalyst, as will be shortly required as noted in the industry report. To assure the large margin of safety in meeting the benzene and formaldehyde SGCs and the acetaldehyde AGC, another meteorological data base was used to calculate these impacts. The results in Table 6.18 did not change from these calculations. Thus, it was determined that no further modeling was necessary for these. On the other hand, for the benzene and formaldehyde AGC exceedences, a few additional model runs were performed to test potential mitigating measures. It is clear that, similar to the criteria pollutant impacts, these high annual impacts are partially due to the low stacks and the associated downwash effects for both the dehydrator and the compressor sources. Given that these two sources already need to include NESHAP control measures, the necessary additional reduction in impacts can be practically achieved only by limiting public access to about 150m from these sources, or by raising their stacks.

An iterative modeling of increased stack heights for both the dehydrator and the compressor demonstrated that in order to achieve the corresponding AGCs, the stack of the dehydrator should be a minimum of 9.1m (3 0ft), in which case it will also avoid building downwash effects, while the compressor stack must be raised to 7.6m (25ft). These higher stacks were then modeled using each of the 12 years of meteorological data and the resultant overall maxima, tabulated in the bottom half of the “Max annual” column in Table 6.18. It should be noted that these modifications to stack height will also reduce the corresponding 1 hour maxima leading to a larger margin of compliance with SGCs. With these stack modifications and the NESHAP control measures identified in the industry report, all of the SGCs and AGCs are projected to be met by the various combustion operations and the dehydrator.

The last set of toxic pollutants modeled was the representative subset of additive chemicals used in hydraulic fracturing operations for the onsite and centralized impoundments. The impacts of the set of representative pollutants in the flowback water in Table 6.13 were modeled using a unitized (1 g/s) emission rate which is input to the model on a per unit area basis (m^2) for the area source modeling. The 1-hour and annual “normalized” (at 1 g/s) impacts for each impoundment was then determined for each of the meteorological data years, and then the overall maxima were used with the actual emissions of each pollutant to calculate the actual pollutant concentrations. The “normalized” impacts for each year of the data and the overall maxima are presented in Table 6.19. Note that these values are merely “non-dimensionalized” entries not related to actual emissions of the impoundments.

The actual emission rates for the chemicals were calculated from the corresponding water concentrations from Table 6.13, the transfer coefficients calculated per the procedures discussed in Section 6.5.2.3, and the area of the two impoundments, using the equation in Section 5.2 of the aforementioned EPA report. These emissions are presented in column 2 of Table 6.20. The maximum overall unitized impacts from Table 6.19 for each averaging time and impoundment size were then used to calculate the corresponding maximum 1 hour and annual impacts. These maximum impacts and the associated SGCs/AGCs are presented in Table 6.20.

It is seen that the impacts due to the larger off-site impoundment are higher than those of the smaller on-site one, as would be expected from larger emissions and the "accumulation" of concentrations at the edge of the area source. The ratios of maximum 1 hour impacts to the SGCs and maximum annual impacts to the AGCs are also presented in Table 6.20. In this way, any values above one (which are underlined) indicate an exceedance of an SGC or AGC. The results indicate that the 1hour impacts for most of the chemicals are below the corresponding ambient SGC thresholds. However, the impacts of glutaraldehyde, methanol and heavy naphtha are above the SGCs due to the relatively low value of the SGC for the former and the relatively large concentrations in water for the latter two.

Similarly, the ratios of the annual impacts to the corresponding AGCs indicate a larger number of exceedences; for the central impoundments, five of the 13 chemicals modeled exceed the AGCs, while three of the chemicals are within a factor of two of the AGCs. As discussed previously, it is important to recognize that annual impacts from these impoundments assume quasi-continuous emissions based on limited industry information on the disposition or reuse of the flowback water over the long term and for the multiple wells which could be potentially drilled and completed during a given year. Thus, it is possible that the annual impacts could be overstated, especially for the onsite impoundment, which is less likely to be in a "continuous" mode of operations. In addition, even for the central impoundment, certain pollutants (methanol and heavy naphtha) are emitted at relatively large rates and quantities due to their low solubility in water and large concentrations in the flowback water. For these pollutants, the short-term emission rate in Table 6.20 could be difficult to be maintained over a year without a rather short "replenish" time frame. On the other hand for other pollutants (e.g. acrylamide and glutaraldehyde), the emissions are low enough such that these could be easily maintained over the long term. These considerations have been included in the following discussions of the consequences of these impacts.

It should be noted that all of the SGC and AGC maximum impacts occur near the edge of the impoundments, at the closest receptor of 10 m distance, as expected for these ground level sources. Thus, one of the possible ways to alleviate these impacts is to assure that there is no public access to areas at which the SGCs/AGCs are exceeded. The simplest way to accomplish this is to use the largest of the 1 hour and annual exceedences to calculate a distance at which all of the exceedences would be eliminated, with an imposition of a verifiable exclusion zone. However, it is also possible to eliminate some of these exceedences on a pollutant specific basis by other means, such as eliminating or limiting the use of the compounds with the chemicals at the amounts modeled to cause the exceedance. Table 6.20 indicates a set of approximate "factors" of exceedences which were used to calculate pollutant specific distances from the four years meteorological data associated with the two impoundments and two averaging times identified in Table 6.19. As noted previously, the denser receptor grid used near the impoundments was extended out to 1km for these specific model runs in order to accomplish this task.

The distances from the impoundments at which all of the SGCs and AGCs would be just met for the set of pollutants with exceedences are summarized in Table 6.21. For example, a factor of 2 was used to approximately represent all three ratios close to this value for the annual impacts for the on-site impoundment in Table 6.20. For the onsite impoundment, Table 6.21 indicates that SGC exceedences can be eliminated by erecting a fence (or a similar enforceable measure) at a distance of approximately 140m from its edge in order to preclude public access to the areas of exceedance. Alternately, any gelling agent with heavy naphtha could be eliminated in the hydraulic fracturing water mix, which will result in a somewhat smaller exclusion zone since the rest of the compounds identified to date indicate chemicals with lower ambient thresholds (e.g., guar gum). It is also noted from Table 6.21 that the 140m "fence" distance would alleviate the AGC exceedences for the onsite impoundment. On the other hand, if removal of flowback water from these impoundments or other measures to reduce air emissions could be affected such that emissions would be significantly limited over a year, then the AGC comparisons can be either adjusted or removed accordingly.

For the central off-site impoundment, Table 6.21 shows relatively larger distances for both the SGC and AGC exceedences. In this case, the annual impacts could be more likely realized due to the desire on the part of certain industry to keep these impoundments "open" for up to three years without any mitigation or control measure, and since these could be in quasi-continuous mode of operation in serving a number of well pads. For the 1 hour impacts, the SGC exceedences occur out to relatively large distances, making the imposition of public access restrictions by a fence or similar measure less practical as the only control measure. Thus, restrictions on the chemical use or their concentrations would be the more likely mitigation options. For the annual modeling results, the worst case meteorological data base (Buffalo, 2007) was used to generate a graph which depicts the areas in which the concentrations of the pollutants exceed AGCs. The distances at which the concentrations meet the approximate factors in Table 6.21 were defined as isopleths (lines of constant concentrations) around the impoundment.

The result is presented in Figure 6.7 for all pollutants which exceed the AGCs. The color coded receptors (each “dot” is a receptor on the figure) determine the areas within which the annual impacts are above the AGCs for the chemical noted in the legend. For example, the “deep purple” colored area was calculated by looking for the distance beyond which the maximum impact for methanol need to be reduced by a factor of two per Table 6.21. These results indicate that public access to the larger impoundments must be limited to beyond 765 meters to assure no exposure above any of the AGCs. As noted previously, it is possible that the maximum annual impacts and the distance factors in Tables 6.20 and 6.21, respectively, for methanol and heavy naphtha are overstated due to the inability to maintain their relatively larger short-term emissions over a year. However, the results in Table 6.21 and Figure 6.7 also indicate that, even without these pollutants, the AGC exceedences would still require a large distance from the impoundment to preclude public exposure. In addition, the elimination of heavy naphtha as a gelling agent would not considerably reduce the distance to AGC exceedences in this case. Furthermore, the elimination of glutaraldehyde as a bactericide would not necessarily lead to a lesser distance to an exceedance since the Department has not modeled certain other bactericides in the list from industry due to a lack of necessary information to determine both their emission rates and ambient thresholds.

These latter considerations raise the issue of advisability of allowing flowback water to sit in these large offsite impoundments for a year or more without any control or mitigation measures, as indicated desirable by certain industry operators. In fact, the SEQRA process requires the imposition of mitigation measures to the maximum extent practicable to address any potential expected adverse impacts. Measures to limit both short-term impacts and long-term emissions (as a means to reduce impacts) from these centralized impoundments can be readily devised, and it is recommended that such measures be implemented in lieu of attempting to “fence in” adverse impacts, especially on a long term basis. As discussed, some of the emission rates used in the modeling can be argued to be overly conservative due to previously noted factors, such as the retention times of the chemicals in the impoundments over the long term. However, some of these considerations are balanced by the fact that the Department’s analysis has been limited to a handful of the many chemicals proposed for use in the additives and, furthermore, has relied on in-water concentrations which can vary to a certain extent from site to site. Thus, it is only prudent to apply readily available mitigation measures to minimize air emissions from these impoundments. Lastly, it should be recognized that the predicted impacts presented are dependent on the area of the impoundment; any significant increase in these dimensions could require further assessments.

The suggested mitigation measures are independent of any other regulatory requirements that might be relevant. For example, due to the fact that many of these chemicals are defined as hazardous air pollutants (HAPs), DEC and EPA air regulations might dictate certain other requirements which have to be met if these impoundments were determined to be a major source of HAPs. Since the emissions of methanol and heavy naphtha (which contains HAPs) from the centralized impoundment were relatively large, preliminary calculations were made assuming ten wells would be drilled and the flowback water emissions from these would be all emitted into the atmosphere over a year's period. These calculations indicate that the major source threshold for both individual HAPs (10 tons/year) and combined HAPs (25tons/year) could be exceeded. Thus, it might be necessary to review these emissions for each proposed centralized impoundment using the site specific set of additives and their corresponding emissions.

6.5.2.5 Conclusions

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad at a typical site over the Marcellus Shale. The analysis relied on recommended EPA and DEC modeling procedures and input data assumptions. Due to the extensive area of the Marcellus Shale and other low-permeability gas reservoirs in New York, certain assumptions and simplifications had to be made in order to properly simulate the impacts from a "typical" site such that the results would be generally applicable. At the same time, an adequate meteorological data base from a number of locations was used to assure proper representation of the potential well sites in the whole of the Marcellus Shale area in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were provided by industry and independently verified by DEC staff. The emission information was provided for the gas drilling, completion and production phases of expected operations. On the other hand, emissions of potential additive chemicals from the flowback water impoundments, which were proposed by industry as one means for reuse of water, were not provided by industry or an ICF report to NYSERDA. Thus, emission rates were developed by DEC using an EPA emission model for a set of representative chemicals which were determined to likely control the potential worst case impacts, using information provided by the hydraulic fracturing completion operators. The information included the compounds used for various purposes in the hydraulic fracturing process and the relative content of the various chemicals by percent weight. The resultant calculated emission rates were shared with industry for their input and comment prior to the modeling.

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for DEC-defined threshold levels for non-criteria pollutants. Limitations on simultaneous operations of the various equipment at both onsite and offsite operations for a multi-well pad were included in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

Initial modeling results indicated compliance with the majority of ambient thresholds, but also identified certain pollutants which were projected to be exceeded due to specific sources emission rates and stack parameters provided in the industry report. It was noted that many of these exceedences related to the very short stacks and associated structure downwash effects for the engines and compressors used in the various phases of operations. Thus, limited additional modeling was undertaken to determine whether simple adjustments to the stack height might alleviate the exceedences as one mitigation measure which could be implemented. For the flowback water impoundments, the modeling indicated exceedences of New York 1 hour and annual guideline concentrations for few of the additive chemicals for both the onsite and centralized impoundments. For the on-site impoundments, a practical mitigation measure would be the placement of a fence to preclude public exposure to potential exceedences at a relatively short distance away from the well pad.

Table 6.11 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → / Source ↘	SO_2	NO_2	PM10 &PM2.5	CO	Non-criteria combustion emissions	H_2S and other gas constituents
Engines for drilling	✔	✔	✔	✔	□	
Compressors for drilling	✔	✔	✔	✔	✔	
Engines for hydraulic fracturing	✔	✔	✔	✔	✔	
line heaters	✔	✔	✔	✔	✔	
offsite compressors	✔	✔	✔	✔	✔	
flowback gas flaring	✔	✔	✔	✔	✔	
gas venting						✔
mud-gas separator						✔
glycol dehydrator					✔	✔

Table 6.12 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Years of Meteorology	Latitude/Longitude coordinates
Albany	2007-08	42.747/73.799
Syracuse	2007-08	43.111/76.104
Binghamton	2007-08	42.207/75.980
Jamestown	2001-02	42.153/79.254
Buffalo	2006-07	42.940/78.736
Montgomery	2005-06	41.509/74.266

Table 6. 13 - Selected Representative Pollutants in Hydraulic Fracturing Water Compounds[47]

Pollutant	CAS Number	Purpose-Agent	Agent's % in Water	Max % in Compound	Max Conc. in Water (g/m^3)	SGC (μg/m^3)	AGC (μg/m^3)
acrylamide	79-06-1	friction reducer	0.1%	1%	10	3.0*	0.00077
benzene	71-43-2	corrosion inhibitor	0.001%	0.0001%	0.00001	1300	0.13
xylene	1330-20-7	corrosion inhibitor	0.001%	30%	3	4300	100
ethylene glycol	107-21-1	clay/iron control crosslinker, breaker scale inhibitor	0.06%	30%	180	10,000	400
propylene glycol (Propanediol-1,2)	57-55-6	breaker surfactant	0.1%	50%	500	55,000	2000
diammonium peroxidisulphate	7727-54-0	breaker	0.01%	100%	100	10*	0.28
hydrochloric acid	7647-01-0	acid	0.11%	35%	385	2100	20
glutaraldehyde	111-30-8	bactericide	0.03%	30%	90	20	0.08
monoethanolamine (ethanoamine)	141-43-5	crosslinker corrosion inhibitor	0.006%	30%	18	1500	18
propargyl alcohol	107-19-7	corrosion inhibitor	0.001%	15%	1.5	230*	5.5
methanol	67-56-1	surfactant/crosslinker scale inhibitor	0.12%	82%	984	33,000	4000
formaldehyde	50-00-1	corrosion inhibitor	0.001%	5%	0.5	30	.06
heavy naphtha	64742-48-9	gelling agent	0.05%	55%	275	4300*	700*

[47] SGC or AGC with * notation were not in DEC's AG-1 tables and were developed by DEC's Toxics Assessment Section with NYSDOH assistance.

Table 6. 14 - National Ambient Air Quality Standards (NAAQS), PSD increments and Significant Impact Levels (SILs) for Criteria Pollutants (µg/m3).

Pollutant	1 hour	3 hour	8 hour	24 hour	annual
SO_2 NAAQS		1300		365	80
PSD Increment		512		91	20
SILs		25		5	1
PM10 NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM2.5 NAAQS				35	15
SILs[48]				5.0/1.2	0.3
NO_2 NAAQS					100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

[48] The PM2.5 standards reflect the 3 year averages with the 24 hour standard beingcalculated as the 98th percentile value. In addition, there are currently no SILs defined by EPA,but the values tabulated are those from DEC's CP-33 (5 ug/m^3 value) and recommended to EPAby Northeast States for Coordinated Air Use Management (NESCAUM).

Table 6. 15 - Maximum Background Concentrations from DEC Monitor Sites

Pollutant	Monitor Sites	Maximum Observed Values for 2005-2007 (μg/m^3)
SO_2	Elmira* and Belleayre	3 hour-125 24 hour- 37 Annual- 8
NO_2	Amherst	Annual- 26
PM10**	Newburg* and Belleayre	24 hour- 49 Annual-13
PM2.5	Newburg* and Pinnacle State Park	24 hour- 30 Annual-11 (3 year averages per NAAQS)
CO	Loudonville	1 hour-1714 8 hour-1112

Note: * Denotes the site with the higher numbers.

**** For PM10, data from years 2002-4 was used.**

Table 6.16 - Maximum Impacts of Criteria Pollutant for Each Meteorological Data Set

Met Year & Location		SO_2			PM10		PM2.5*		CO		NO_2
		3hour	24 hour	Annual	24 hour	Annual	24hour	Annual	1 hour	8 hour	Annual
Albany	2007	15.4	13.3	3.1	459	2.7	355	2.7	9270	8209	57.9
	2008	15.3	13.2	2.9		2.4		2.4	9262	8298	51.0
Syracuse	2007	15.9	12.6	2.8		2.7		2.7	8631	7849	57.1
	2008	15.8	14.3	2.7		2.7		2.7	8626	7774	55.4
Binghamton	2007	18.5	13.4	2.3		2.1		2.1	10122	8751	45.5
	2008	18.6	15.4	1.9		1.8		1.8	9970	8758	37.6
Jamestown	2001	16.7	14.0	2.4		2.1		2.1	8874	8193	46.4
	2002	16.8	14.4	2.7		2.3		2.3	8765	8199	50.9
Buffalo	2006	16.6	15.7	3.2		2.9		2.9	9023	8067	63.2
	2007	16.9	14.4	3.1		2.8		2.8	8910	8270	60.8
Montgomery	2005	17.4	11.6	1.9		1.8		1.8	9362	8226	38.4
	2006	14.4	14.0	2.2		2.0		2.0	9529	8301	41.9
Maximum		18.6	15.7	3.2		2.9		2.9	10122	8758	63.2
Impact at 500m		0.3	0.3	0.05	7.1	.11	5.0	.11	480	253	2.5

Note: 24 hour PM2.5 values are the 8th highest impact per the standard.

Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards

Pollutant and Averaging Time	Maximum Impact ($\mu g/m^3$)	SIL*	Worst Case Background Level ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Increment Impact** ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
SO_2 - 3 hour	18.6	25	125	143.6	1300	18.6	512
SO_2 - 24 hour	15.7	5	37	52.7	365	15.7	91
SO_2 - Annual	3.2	1	8	11.2	80	3.2	20
PM10 - 24 hour	459	5	49	508	150	6.5**	30
PM10 - Annual	2.9	1	13	15.9	50	2.9	17
PM2.5 - 24 hour	355	1.2/5.0	30	385	35	NA	None
PM2.5 - Annual	2.9	0.3	11	13.9	15	NA	None
NO_2 - Annual	63.2	1.0	26	89.2	100	5.6**	25
CO - 1 hour	10,122	2000	1714	11,836	40,000	NA	None
CO - 8 hour	8758	500	1112	9870	10,000	NA	None

Notes: *** SILs for PM2.5 are only used to determine the need for a cumulative analysis or for an EIS per CP-33 since currently there are no EPA promulgated levels.**
**** Impacts from the compressor plus the line heater only for PSD increment comparisons were recalculated for NO_2 and PM10 24 hour cases. NA means not applicable.**

Table 6.18 - Maximum Impacts of Non-criteria Pollutants and Comparisons to SGC/AGC and NewYork state AAQS

Pollutant	Total Venting Emissions Rate (g/s)	Impacts from all Venting Sources (μg/m^3) Max 1hour	SGC	All Combustion Sources and Dehydrator Impacts(μg/m^3) Max 1 hour	SGC	Max Annual	AGC
Benzene	0.218	140	1300	13.2	1300	0.90 0.10	0.13
Xylene	0.60	365	4300	NA**	4300	NA	100
Toluene	0.78	500	37,000	NA	37,000	NA	5000
Hexane	9.18	5888	43,000				
H_2S	0.096	61.5 12.1	14*				
Formaldehyde				4.4	30	0.20 0.04	0.06
Acetaldehyde				NA	4500	0.06	0.45
Naphthalene				NA	7900	NA	3.0
Propylene				NA	21,000	NA	3000

NOTE: * denotes the New York State 1 hour standard for H_2S.

** NA denotes not analyzed by modeling, but it is concluded that the SGCs and AGCs will be met (see text).

Table 6.19 - Impoundment Normalized (1 g/s) Area Source Impacts

		Onsite 15 x 45 m		Offsite 150 x 150 m	
Site	**Year**	**1 hour**	**Annual**	**1 hour**	**Annual**
Albany	**2007**	**54484**	**2117**	**4125**	**245**
	2008	**56057**	**2291**	**4085**	**264**
Syracuse	**2007**	**80184**	**2624**	**5329**	**342**
	2008	**77135**	**2905**	**5322**	**354**
Binghamton	**2007**	**44640**	**1791**	**3195**	**225**
	2008	**46961**	**1991**	**3207**	**229**
Jamestown	**2001**	**65592**	**2363**	**6942**	**268**
	2002	**73725**	**2470**	**6988**	**279**
Buffalo	**2006**	**49820**	**2835**	**3376**	**329**
	2007	**47759**	**3057**	**3398**	**355**
Montgomery	**2005**	**52434**	**2579**	**4216**	**303**
	2006	**53075**	**2553**	**4206**	**298**
Max		**80184**	**3057**	**6988**	**355**

Table 6.20 - Comparison of Maximum Impoundment Fluid Additives Impacts to Ambient Thresholds

Pollutant	Emission Rate (g/s) Central / Onsite	Max 1hour Impact(μg/m^3) Central/Onsite	SGC μg/m^3	Max 1 hour to SGC ratio Central/Onsite	Max annual Impact(μg/m^3) Central /Onsite	AGC μg/m^3	Max annual to AGC ratio Central/Onsite
acrylamide	1.24E-5 / 4.48E-7	8.6E-2 / 3.6E-2	3.0	0.03 / 0.01	4.4E-3 / 1.4E-3	0.00077	5.7 / 1.8
benzene	6.10E-7 / 1.19E-8	4.3E-3 / 9.5E-4	1300	3E-6 / 1E-6	2.2E-4 / 3.6E-5	0.13	0.002 / 0.0003
xylene	1.94E-1 / 3.78E-3	1.4E+3 / 3.0E+2	4300	0.3 / 0.07	6.9E+1 / 1.2E+1	100	0.7 / 0.1
ethylene glycol	1.66E-3 / 6.00E-5	1.2E+1 / 4.8	10,000	0.001 / 5E-4	5.9E-1 / 1.8E-1	400	0.001 / 0.0005
propylene glycol (Propanediol-1,2)	3.15 / 1.06E-1	2.2E+4 / 8.5E+3	55,000	0.4 / 0.15	1.1E+3 / 3.2E+2	2000	0.6 / 0.2
diammonium peroxidisulphate	9.45E-5 / 3.43E-6	6.6E-1 / 2.8E-1	10	0.07 / 0.03	3.4E-2 / 1.1E-2	0.28	0.1 / 0.04
hydrochloric acid	1.34E-3 / 4.85E-5	9.34 /3.9	2100	0.004 / 0.002	4.8E-1 / 1.5E-1	20	0.02 / 0.01
glutaraldehyde (pentaredial)	1.25E-2 / 4.54E-4	8.8E+1 / 3.6E+1	20	4.4 / 1.8	4.4 / 1.4	0.08	55.6 / 17.3
monoethanolamine (ethanoamine)	2.69E-2 / 9.58E-4	1.9E+2 / 7.7E+1	1500	0.13 / 0.05	9.5 / 2.9	18	0.5 / 0.2
propargyl alcohol	8.64E-3 / 2.95E-4	6.0E+1 / 2.4E+1	230	0.3 / 0.1	3.1 / 9.0E-1	5.5	0.6 / 0.2
methanol	2.42E+1/ 7.15E-1	1.7E+5 / 5.7E+4	33,000	5.1 / 1.7	8.6E+3 / 2.2E+3	4000	2.1 / 0.6
formaldehyde	1.05E-3 / 3.74E-5	7.34 /3.0	30	0.2 / 0.1	3.7E-1 / 1.1E-1	0.06	6.2 / 1.9
heavy naphtha	1.5E+1 / 4.49E-1	1.1E+5 /3.6E+4	4300	24.3 / 8.4	5.3E+3 / 1.4E+3	700	7.6 / 2.0

Table 6.21 - Distances from Impoundments Necessary to Meet SGCs and AGCs

Impoundment and Averaging	Pollutant and "Reduction Factor"	Distance (in meters)
On-site SGCs	**Heavy Naphtha – 8** **Methanol & Glutaraldehyde - 2**	**140** **<15**
On-site AGCs	**Glutaraldehyde – 17** **Acrylamide, formaldehyde & heavy naphtha - 2**	**100** **<15**
Off-site SGCs	**Heavy Naphtha - 25** **Methanol & Glutaraldehyde - 5**	**> 1000** **340**
Off-site AGCs	**Glutaraldehyde - 55** **Acrylamide, formaldehyde & heavy naphtha - 7** **Methanol - 2**	**765** **165** **30**

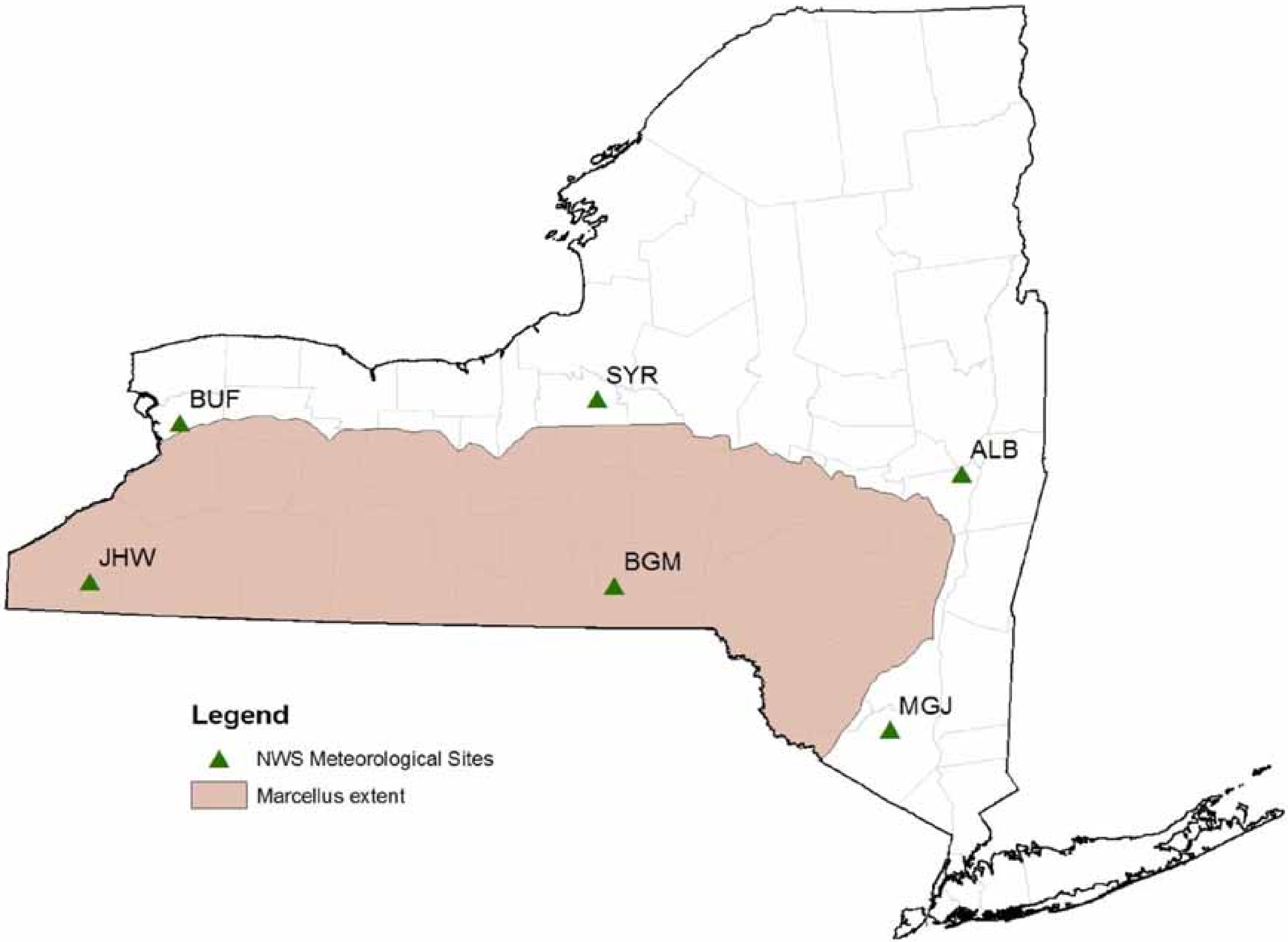


Figure 6.4 - Marcellus Shale Extent

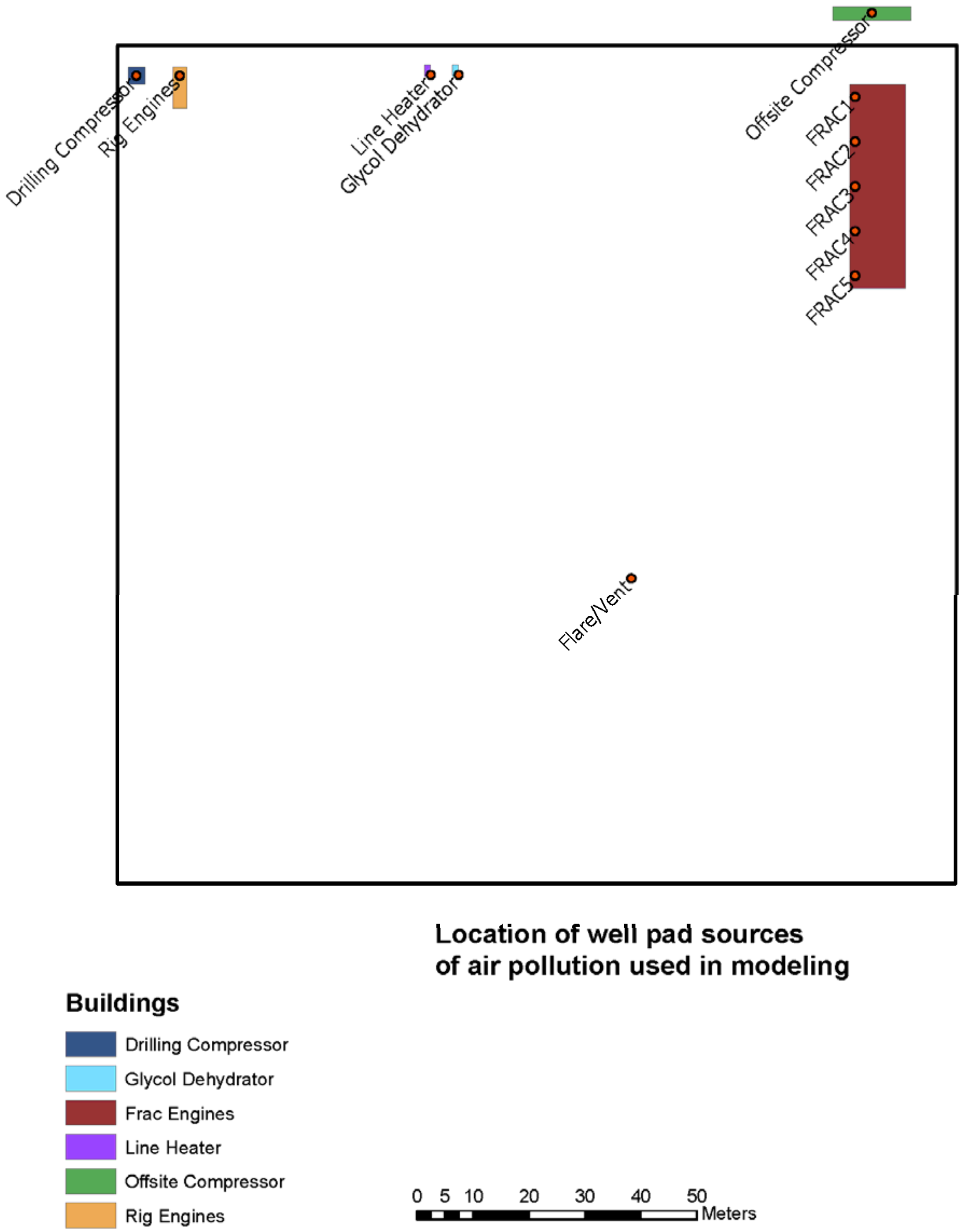


Figure 6.5 - Location of Well Pad Sources of Air Pollution Used in Modeling

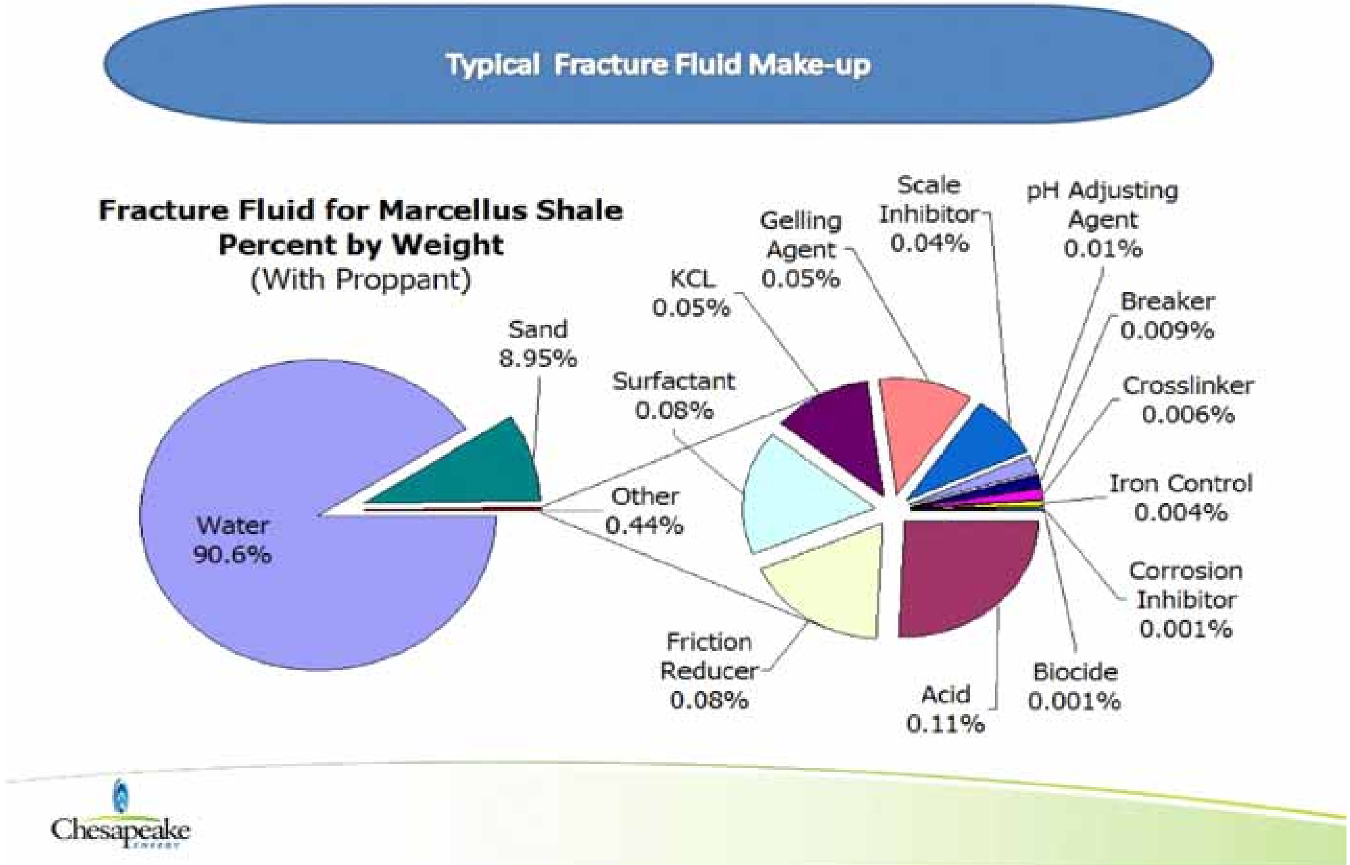


Figure 6. 2 - Percent by Weight of Hydraulic Fracturing Additive Compounds

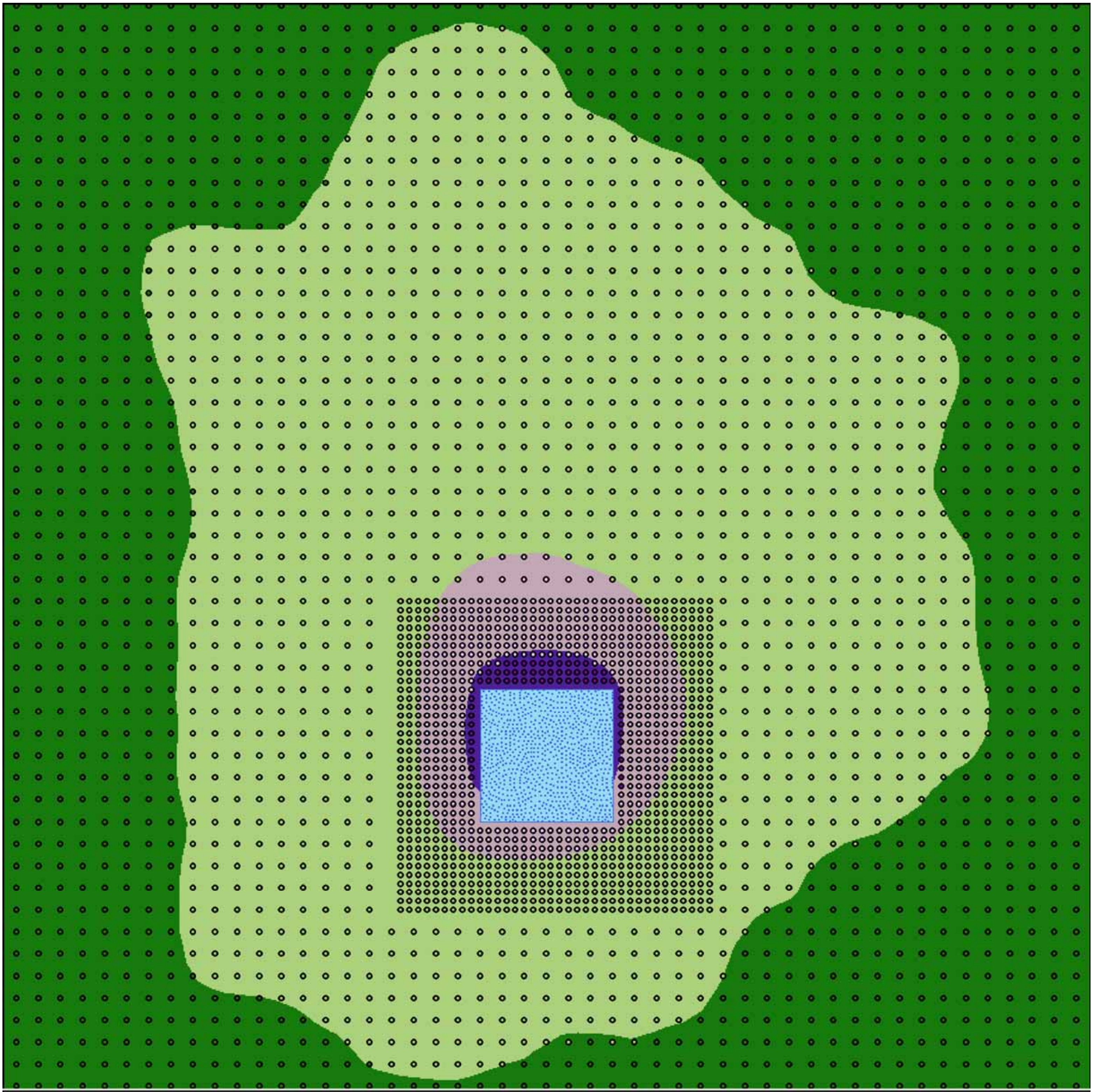


Figure 6. 3 - Centralized Impoundment Annual Impact Areas for Marcellus Shale.

6.6 Greenhouse Gas Emissions

On July 15, 2009, the Department's Office of Air, Energy and Climate issued its *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*.[49] The policy reflected in the guide is used by DEC staff in reviewing an environmental impact statement (EIS) when DEC is the lead agency under the State Environmental Quality Review Act (SEQR) and energy use or greenhouse gas (GHG) emissions have been identified as significant in a positive declaration, or as a result of scoping, and, therefore, are required to be discussed in an EIS. Following is an assessment of potential GHG emissions for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing.

SEQR requires that lead agencies identify and assess adverse environmental impacts, and then mitigate or reduce such impacts to the extent they are found to be significant. Consistent with this requirement, SEQR can be used to identify and assess climate change impacts, as well as the steps to minimize the emissions of GHGs that cause climate change. Many measures that will minimize emissions of GHGs will also advance other long-established State policy goals, such as energy efficiency and conservation; the use of renewable energy technologies; waste reduction and recycling; and smart and sustainable economic growth. The *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement* is not the only State policy or initiative to promote these goals; instead, it furthers these goals by providing for consideration of energy conservation and GHG emissions within EIS reviews.[50]

The goal of this analysis is to characterize and present an estimate of total annual emissions of carbon dioxide (CO_2), and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons, for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. In addition, the major contributors of GHGs are to be identified and potential mitigation measures offered.

[49] Hhttp://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf

[50] Hhttp://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf

6.6.1 Greenhouse Gases

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapor is the most important greenhouse gas, and CO_2 is the second-most important one.[51] Human activities result in emissions of four principal greenhouse gases: CO_2, methane (CH_4), nitrous oxide (N_2O) and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time. Many human activities contribute greenhouse gases to the atmosphere.[52] Whenever fossil fuel (coal, oil or gas) burns, CO_2 is released to the air. Other processes generate CH_4, N_2O and halocarbons and other greenhouse gases that are less abundant than CO_2, but even better at retaining heat.[53]

6.6.2 Emissions from Oil and Gas Operations

Greenhouse gas emissions from oil and gas operations are typically categorized into 1) vented emissions, 2) combustion emissions and 3) fugitive emissions. Below is a description of each type of emission. For the noted emission types, no distinction is made between direct and indirect emissions in this analysis. Further, this GHG discussion is focused on CO_2 and CH_4 emissions as these are the most prevalent GHGs emitted from oil and gas industry operations, including expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. Virtually all companies within the industry would be expected to have emissions of CO_2 - and, to a lesser extent, CH_4 and N_2O - since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced in varying quantities, from oil and gas wells. Because the quantities of N_2O produced through combustion are quite small

[51] IPCC, 2007: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 98. Hhttp://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdfH

[52] IPCC, 2007: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Pg. 100. [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Hhttp://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdfH

[53] Hhttp://www.dec.ny.gov/energy/44992.htmlH

compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[54]

6.6.2.1 Vented Emissions

Vented sources are defined as releases resulting from normal operations. Vented emissions of CH_4 can result from the venting of natural gas encountered during drilling operations, flow from the flare stack during the initial stage of flowback, pneumatic device vents, dehydrator operation, and compressor start-ups and blowdowns. Oil and natural gas operations are the largest human-made source of CH_4 emissions in the United States and the second largest human-made source of CH_4 emissions globally. Given methane's role as both a potent greenhouse gas and clean energy source, reducing these emissions can have significant environmental and economic benefits. Efforts to reduce CH_4 emissions not only conserve natural gas resources but also generate additional revenues, increase operational efficiency, and make positive contributions to the global environment.[55]

6.6.2.2 Combustion Emissions

Combustion emissions can result from stationary sources (e.g., engines for drilling, hydraulic fracturing and natural gas compression), mobile sources and flares. Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of hydrocarbon combustion. Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete combustion of the fuel gas, which is emitted as unburned CH_4. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions.[56]

6.6.2.3 Fugitive Emissions

Fugitive emissions are defined as unintentional gas leaks to the atmosphere and pose several challenges for quantification since they are typically invisible, odorless and not audible, and

---

[54] International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003., p. 5-2.

[55] Hhttp://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf

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

often go unnoticed. Examples of fugitive emissions include CH_4 leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies.[57] In the context of GHG emissions, fugitive sources within the upstream segment of the oil and gas industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant.[58]

6.6.3 Emissions Source Characterization

Emissions of CO_2 and CH_4 occur at many stages of the drilling, completion and production phases, and can be dependent upon technologies applied and practices employed. Considerable research – sponsored by the American Petroleum Institute (API), the Gas Research Institute (GRI) and the United States Environmental Protection Agency (USEPA) – has been directed towards developing relatively robust emissions estimates at the national level.[59] The analytical techniques and emissions factors, and mitigation measures, developed by the these agencies were used to evaluate GHG emissions from activities necessary for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing.

In 2009, the New York State Energy Research and Development Authority (NYSERDA) contracted ICF International (ICF) to assist with supporting studies for the development of the SGEIS. ICF's work included preparation of a technical analysis of potential impacts to air in the form of a report finalized in August 2009.[60] The report, which includes a discussion on GHGs,

---

[57] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, *Task 2 – Technical Analysis of Potential Impacts to Air*, August 2009, NYSERDA Agreement No. 9679. p. 21.

[58] International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003., p. 5-6

[59] Center for Climate Strategies prepared for New Mexico Environment Department, November 2006., *Appendix D New Mexico Greenhouse Gas Inventory and Reference Case Projections, 1990-2020*., pp. D-35.

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

provided the basis for the following in-depth analysis of potential GHGs from the subject activity. ICF's referenced study identifies drilling, completion and production operations and equipment that contribute to GHG emission and provides corresponding emission rates, and this information facilitated the following analysis by identifying system components on an operational basis. As such, wellsite operations considered in the SGEIS were divided into the following phases for this GHG analysis.

- Drilling Rig Mobilization, Site Preparation and Demobilization
- Completion Rig Mobilization and Demobilization
- Well Drilling
- Well Completion (includes hydraulic fracturing and flowback)
- Well Production

Transport of materials and equipment is integral component of the oil and gas industry. Simply stated, a well cannot be drilled, completed or produced without GHGs being emitted from mobile sources. NTC Consultants (NTC), which was also contracted by NYSERDA in support of SGEIS preparation, performed an impact analysis on community character of horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability gas reservoirs. NTC determined that the subject activity would require significantly more trucking than was addressed by the 1992 GEIS. NTC estimated required truck trips per well for the noted phases requiring transportation as follows:[61]

<u>Drilling Rig Mobilization, Site Preparation and Demobilization</u>	
Drill Pad and Road Construction Equipment	10 – 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 – 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 – 50 Truckloads
<u>Completion Rig Mobilization and Demobilization</u>	
Completion Rig	15 Truckloads

[61] NTC Consultants. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, September 2009.

<u>Well Completion</u>	
Completion Fluid and Materials	10 - 20 Truckloads
Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads
<u>Well Production</u>	
Production Equipment	5 – 10 Truckloads

In this analysis, two transportation scenarios were developed and evaluated for the sourcing of equipment and materials, and the disposal of wastes (i.e. frac flowback waters, production brine). For simplification, any subsequent reference in this analysis to "sourcing" includes both incoming and outgoing equipment and materials to and from the wellsite or wellpad. Both transportation scenarios incorporated NTC's estimates for truck trips, including the ranges of needed truckloads. An in-state sourcing option assuming a round-trip mileage of twenty miles (e.g., local) and an out-of-state sourcing option assuming a round-trip mileage of four hundred miles (e.g., originating from central Pennsylvania) were used to determine total vehicle miles traveled (VMT) associated with site preparation and rig mobilizations, well completion and well production activities. As further discussed below, when actual or estimated fuel use data was not available, VMT formed the basis for estimating CO_2 emissions. However, to illustrate the impact of out-of-state sourcing compared to in-state sourcing on GHG emissions, and to present a worst-case scenario, an all-or-nothing approach was used in that all materials, equipment and disposal of production brine were represented as wholly sourced from either in-state or out-of-state. Actual operations at a single well or multiple well pad may involve a combination of sourcing from both in-state and out-of-state. Nevertheless, it was demonstrated through this analysis that in-state sourcing is the preferred option with respect to minimizing GHG emissions.

In addition to accounting for the two sourcing scenarios described above, two distinct types of well projects were evaluated for GHG emissions as follows.

- Single-Well Project
- Ten-Well Pad

In calculating VMT for rig and equipment mobilizations for each of the project types noted above, it was assumed that all work involving the same activity would be finished before commencing a different activity. In other words, the site would be prepared and the drilling rig mobilized, then all wells (i.e., one or ten) would be drilled, followed by the completion of all wells (i.e., one or ten) and subsequent production of all wells (i.e., one or ten). A number of operators have indicated to the Department that activities will be conducted sequentially, whenever possible, to realize the greatest efficiency but the actual order of work events and number of wells on a given pad may vary.

Stationary engines and equipment emit CO_2 and/or CH_4 during drilling and completion operations. However, most are not typically operating at their full load every hour of each day while on location. For example, certain engines may be shut down completely or operating at a very low load during bit trips, geophysical logging or the running of casing strings. Consequently, for the purpose of this analysis and as noted in Table 6.13 it was assumed that engines and equipment for drilling and completion operations generally operate at full load for 50% of their time on location. Exceptions to this included engines and equipment used for hydraulic fracturing and flaring operations. Instead of relying on an assumed time frame for operation for the many engines that drive the high-pressure high volume pumps used for hydraulic fracturing, an average of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used.[62] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.13 - Assumed Drilling & Completion Time Frames Per Well

Operation	Estimated Duration (days / hrs.)	Full Load Operational Duration for Related Equipment (days / hrs.)
Well Drilling	28 / 336	14 / 168
Completion	3 / 72 (frac) 2 / 48 (rig)	3 / 72 (frac) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

[62] ALL Consulting, *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* August 2009., Table 11, p. 10.

Stationary engines and equipment also emit CO_2 and/or CH_4 during production operations. In contrast to drilling and completion operations, production equipment generally operates around the clock (i.e., 8,760 hours per year) except for scheduled or intermittent shutdowns.

6.6.4 Emission Rates

The primary reference for emission rates for stationary production equipment considered in this analysis is the GRI's *Methane Emissions from the Natural Gas Industry*. Table GHG-1 "Emission Rates for Well Pad" in Appendix 19, Part A shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well production operations. Table GHG-1 was adapted from an analysis of potential impacts to air performed in 2009 by ICF International under contract to NYSERDA. GHG emission rates for flaring during the completion phase were also obtained from the ICF International study. The emission factors in the table are typically listed in units of pounds emitted per hour for each piece of equipment. The emissions rates specified in the table were used to determine the annual emissions in tons for each stationary source, except for engines used for rig and hydraulic fracturing engines, using the below equation. The *Activity Factor* represents the number of pieces of equipment or occurrences.

$$\boldsymbol{Emissions}\left(\frac{\boldsymbol{tons}}{\boldsymbol{yr.}}\right) = \boldsymbol{Emissions\ Factor}\left(\frac{\boldsymbol{lbs.}}{\boldsymbol{hr.}}\right) \times \boldsymbol{Duration}(\boldsymbol{yr.}) \times \left(\frac{\boldsymbol{8,760\ hrs.}}{\boldsymbol{yr.}}\right) \times \left(\frac{\boldsymbol{1\ US\ short\ ton}}{\boldsymbol{2000\ lbs.}}\right) \times \textbf{Activity Factor}$$

A material balance approach based on fuel usage and fuel carbon analysis, assuming complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2), is the preferred technique for estimating CO_2 emissions from stationary combustion engines.[63] This approach was used for the engines required for conducting drilling and hydraulic fracturing operations. Actual fuel usage, such as the volume of fuel needed to perform hydraulic fracturing, was used where available to determine CO_2 emissions. For emission sources where actual fuel usage data was not available, estimates were made based on the type and use of the engines needed to perform the work. For GHG emission from mobile sources, such as trucks used to transport equipment and materials, VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile sources. A sample calculation showing this

[63] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005., p. 4-3.

methodology for determining combustion emissions (CO_2) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH_4 emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of ten million cubic feet per day. ICF International's calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wellsite operations. Transportation sources may include vehicles such as cars and trucks used for work-related personnel transport, as well as tanker trucks and flatbed trucks used to haul equipment and supplies. The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The USEPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH_4 and N_2O emissions from mobile sources is to assume that these emissions are negligible compared to CO_2.[64]

An alternative to using modeling software for determining CO_2 emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of estimated fuel usage. This methodology was used to calculate the tons of CO_2 emissions from

[64] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005., pp. 4-32, 4-33.

mobile sources related to the subject activity. A sample CO_2 emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO_2 emission estimates from transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. Table GHG-2 assumes that the same rig stays on location and drills both the vertical and lateral portions of a well.

As previously mentioned, because all activities are assumed to be performed sequentially requiring a single rig move, the GHG emissions presented in Table GHG-2 are representative of either a one-well project or ten-well pad. As shown in the table, approximately 14 to 17 tons of CO_2 emissions are expected from an in-state move of the drilling rig, including site preparation. For the out-of state scenario of drilling rig mobilization and demobilization, it is estimated that such a move, including site preparation, would result in 69 to 123 tons of CO_2 emissions. The calculated CO_2 emissions presented in the table illustrate the impact of sourcing equipment and materials from out-of-state (400-mile round trip per vehicle assumed) opposed to sourcing of materials and equipment in-state (20-mile round trip per vehicle assumed). Comparatively, using the aforementioned round-trip mileages of 20 and 400, approximately five to six times the amount of CO_2 emissions are generated during drilling rig mobilization, site preparation and demobilization if equipment is sourced from out-of-state compared to an in-state move. The calculated CO_2 emissions shown in this table and all other tables included in this analysis have been rounded up to the next whole number.

6.6.6 Completion Rig Mobilization and Demobilization

Table GHG-3 in Appendix 19, Part A includes CO_2 emission estimates for transporting the completion rig to and from the wellsite, considering an in-state (20-mile round trip per vehicle) and out-of-state (400-mile round trip per vehicle) move. As shown in the table, approximately one ton of CO_2 emissions may be generated from an in-state move of the completion rig. For the out-of-state scenario for rig mobilization and demobilization, it is estimated that such a move would result in 10 tons of CO_2 emissions. As with the transport of the drilling rig, the estimated CO_2 emissions shown in Table GHG-3 illustrate the impact of sourcing the completion equipment and materials from out-of-state, as opposed to sourcing of materials and equipment in-state.

6.6.7 Well Drilling

Well drilling activities include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for CO_2 emissions generated by these stationary sources. As shown in the table, approximately 94 tons of CO_2 emissions per well will be generated as a result of drilling operations.

6.6.8 Well Completion

Well completion activities include 1) transport of required equipment and materials to and from the site, 2) hydraulic fracturing of the well, 3) a flowback period, including flaring, to clean the well of frac fluid and excess sand used as the hydraulic fracturing proppant, 4) drilling out of hydraulic fracturing stage plugs and the running of production tubing by the completion rig and 5) site reclamation. Mobile and stationary engines, and equipment used during the aforementioned completion activities emit CO_2 and/or CH_4. Tables GHG-5 and GHG-6 in Appendix 19, Part A include estimates of individual and total emissions of CO_2 and CH_4 generated during the completion phase for a one-well project and a ten-well pad, respectively.

Similar to the above discussion regarding mobilization and demobilization of rigs, transport of equipment and materials, which results in CO_2 emissions, is necessary for completion of wells. Again, both in-state and out-of-state sourcing scenarios, including the ranges of truckloads, were developed for a one-well project and a ten-well pad, and evaluated for GHG emissions for the completion phase. The results of this evaluation are shown in Tables GHG-5 and GHG-6 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on VMT, which ultimately requires a determination of fuel usage. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-5, transportation related completion-phase emissions of CO_2 for a one-well project is estimated at 25 to 37 tons and 504 to 737 tons from in-state and out-of-state sourcing, respectively. For the ten-well pad (see Table GHG-6), transportation related completion-phase CO_2 emissions are estimated at 208 to 310 tons for in-state and 4,161 to 6,209 tons for out-of-state sourcing, respectively. The out-of-state sourcing scenarios are significantly higher than the in-state scenarios because of the number of truckloads required for the flowback water tanks, hauling of fresh water and the ultimate removal of flowback waters from the sites. This speaks to the benefits of in-state sourcing opposed to out-of-state sourcing with respect to potential CO_2 emissions generated for transportation during the completion phase.

Hydraulic fracturing operations require the use of many engines needed to drive the high-pressure high-volume pumps used for hydraulic fracturing (see multiple "Pump trucks" in the Photos Section of Chapter 6). As previously discussed and shown in Table GHG-5 in Appendix 19, Part A, an average (i.e., 29,000 gallons of diesel) of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used to calculate the estimated amount of CO_2 emitted during hydraulic fracturing. Tables GHG-5 and GHG-6 show that approximately 325 tons of CO_2 emissions per well will be generated as a result of hydraulic fracturing operations.

Subsequent to hydraulic fracturing in which fluids are pumped into the well, the direction of flow is reversed and flowback waters, including reservoir gas, are routed through separation equipment to remove excess sand, then through a line heater and finally through a separator to separate water and gas on route to the flare stack. Generally speaking, flares in the oil and gas industry are used to manage the disposal of hydrocarbons from routine operations, upsets, or emergencies via combustion.[65] However, only controlled combustion events will be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of three days was considered for this analysis although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. Once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas into the sales line.[66] As shown in Table GHG-5 in Appendix 19, Part A, approximately 576 tons of CO_2 and 4 tons of CH_4

---

[65] American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, Washington DC, 2004; amended 2005. pp. 4-27.

[66] ALL Consulting, *Horizontally Drilled/High-Volume Hydraulically Fractured Wells Air Emissions Data,* August 2009.. p. 14.

emissions are generated per well during a three-day flaring operation for a ten million cubic foot per day flowrate. As mentioned above, the actual duration of flaring may be more or less. The CH_4 emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO_2 and CH_4 emissions rates using an average Marcellus gas composition.[67] The duration of flaring operations may be significantly shortened by using specialized gas recovery equipment, provided a gas sales line is in place at the time of commencing flowback from the well. Recovering the gas to a sales line, instead of flaring it, is called a "reduced emissions completion" (REC) or "green completion" and is further discussed in Section 7.6 as a possible mitigation measure, and in Appendix 25 (REC Executive Summary included by ICF for its work in support of preparation of the SGEIS).

The final work conducted during the completion phase consists of using a completion rig, possibly a coiled-tubing unit, to drill out the hydraulic fracturing stage plugs and run the production tubing in the well. Assuming a fuel consumption rate of 25 gallons per hour and an operating period of 24 hours, the rig engines needed to perform this work emit CO_2 at a rate of approximately 7 tons per well. After the completion rig is removed from the site, the area will be reworked and graded by earth-moving equipment, which adds another 6 tons of CO_2 emissions for either a one-well project or ten-well pad. Tables GHG-5 and GHG-6 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a one-well project and ten-well pad respectively.

6.6.9 Well Production

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. Consistent with the approach used to analyze GHG emissions from other phases of work, two transportation scenarios were developed and evaluated for the sourcing of equipment and materials. Both transportation scenarios incorporated NTC's estimates for truck trips including the ranges in numbers of needed

[67] ICF Incorporated, LLC. Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program. Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs, *Task 2 – Technical Analysis of Potential Impacts to Air,* August 2009, NYSERDA Agreement No. 9679. p. 28.

truckloads. An in-state sourcing option assuming a round-trip mileage of twenty miles and an out-of-state sourcing option assuming a round-trip mileage of four hundred miles were used to determine total VMT associated with well production activities, including removal of produced brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant CO_2 emissions. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite results in CO_2emissions of approximately 0.1 ton for in-state sourcing and 3 to 6 tons for out-of-state sourcing, respectively.

Well production may require the removal of produced brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO_2 emissions. In-state and out-of-state disposal transportation scenarios were developed to determine CO_2 emissions from each scenario, and emission estimates are presented in Tables GHG-7, GHG-8, GHG-9 and GHG-10 in Appendix 19, Part A. Table GHG-7 presents CO_2 and CH_4 emissions for a one-well project for the period of production remaining in the first year after the single well is drilled and completed. For the purpose of this analysis, the duration of production for a one-well project in its first year was estimated at 329 days (i.e., 365 days minus 36 days to drill & complete). Table GHG-8 shows estimated annual emissions for a one-well project commencing in year two, and producing for a full year. Table GHG-9 presents CO_2 and CH_4 emissions for a ten-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 5 days (i.e., 365 days minus 360 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-10 shows estimated annual emissions for a ten-well project commencing in year two, and producing for a full year.

GHGs in the form of CO_2 and CH_4 are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH_4 emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine's internal combustion cycle results in CO_2 emissions while compression of the natural gas generates CH_4 fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.[68] The emission rates presented in Table GHG-1, Appendix 19, Part A "Emission Rates for Well Pad" were used to calculate estimated emissions of CO_2 and CH_4 for each stationary source for a one-well project and ten-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-7, GHG-8, GHG-9 and GHG-10 in Appendix 19, Part A. Based on the specified emissions rates for each piece of production equipment, the calculated annual GHG emissions presented in the Tables GHG-8 and GHG-10 show that the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH_4 emissions during the this phase, while operation of pneumatic device vents also generates vented CH_4 emissions. The amount of CH_4 vented in the compressor exhaust was not quantified in this analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for "about 7.9% of methane emissions from the natural gas industry."

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2) Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion (includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was analyzed for potential GHG emissions, with a focus on CO_2 and CH_4 emissions. The results of these phase-specific analyses for a one-well project and ten-well pad are detailed in Tables GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year

[68] EPA., Lessons Learned From Natural Gas Star Partners, *Reduced Methane Emissions from Compressor Rod Packing Systems*, 2006. Hhttp://www.epa.gov/gasstar/documents/ll_rodpack.pdfH

thereafter for each project type (i.e., one-well & ten-well) with consideration to both in-state and out-of-state sourcing of equipment and materials.

The goal of this review is to characterize and present an estimate of total annual emissions of CO_2, and other relative GHGs, as both short tons and CO_2e expressed in short tons for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing . To determine CO_2e, each greenhouse gas has been assigned a number or factor that reflects its global warming potential (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2 released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory. Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.[69] For example, Chesapeake Energy Corporation's July 2009 Fact Sheet on greenhouse gas emissions states that CO_2 has a GWP of 1 and CH_4 has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO_2e.[70] However, GWP factors are continually being updated, and for the purpose of this analysis as required by the Department's 2009 *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*, the 100-Year GWP factors provided in below Table 6.23 were used to determine total GHGs as CO_2e. Tables GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A include a summary of estimated CO_2 and CH_4 emissions from the various operational phases as both short tons and as CO_2e expressed in short tons.

[69] American Petroleum Institute., *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-5, August 2009. Hhttp://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf
[70] Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

Table 6.14 - Global Warming Potential for Given Time Horizon[71]

Common Name	Chemical Formula	20-Year GWP	100-Year GWP	500-Year GWP
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.6

Table 6.24 is a summary of total estimated CO_2 and CH_4 emissions for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing, as both short tons and as CO_2e expressed in short tons. The below table includes emission estimates for the first full year in which drilling is commenced and subsequent producing years for each project type (i.e., one-well & ten-well) with consideration of both in-state and out-of-state sourcing of equipment and materials. While somewhat masked by the first-year data presented below for the one-well project, out-of-state sourcing (including disposal) in the first year of well activities significantly contributes to increased CO_2 emissions for initial development of both the one-well project and ten-well pad. Still, these activities generally represent one-time events of relatively short duration.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual emissions and thus production operations contribute relatively greater amounts of GHG emissions on a CO_2e basis than do the cumulative impacts of rig mobilizations, well drilling and well completion. As noted above, for the purpose of assessing GHG impacts, each ton of CH_4 emitted is equivalent to 25 tons of CO_2. Thus, because of its recurring nature, the importance of limiting CH_4 emissions throughout the production phase cannot be overstated. The last row of the Table 6.15 also includes estimated GHG emissions for ongoing annual production at the ten-well pad on a per well basis. The lower annual emissions per well at the ten-well pad compared to the emissions from annual production at a one-well project demonstrate economy of scale from a GHG perspective and supports the contention that multiple well pads are advantageous for many reasons, including limiting GHGs.

71 Adapted from Forster, P., V. Ramaswamy, P. Artaxo, T. Berntsen, R. Betts, D.W. Fahey, J. Haywood, J. Lean, D.C. Lowe, G. Myhre, J. Nganga, R. Prinn, G. Raga, M. Schulz and R. Van Dorland, 2007: Changes in Atmospheric Constituents and in Radiative Forcing. *In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Adapted from Table 2.14. Chapter 2, p. 212. Hhttp://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdfH

Table 6.15 - Summary of Estimated Greenhouse Gas Emissions

	CO_2 (tons)		CH_4 (tons)	CH_4 Expressed as CO_2e (tons)[72]	Total Emissions from Proposed Activity CO_2e (tons)	
	In-state Sourcing	*Out-of-state Sourcing*			*In-state Sourcing*	*Out-of-state Sourcing*
Estimated First-Year Green House Gas Emissions from One-Well Project	6,604 – 6,619	7,175 – 7,465	226	5,650	12,254 – 12,269	12,825 – 13,115
Estimated Post First-Year Annual Green House Gas Emissions from One-Well Project	6,163	6,202	244	6,100	12,263	12,302
Estimated First-Year Green House Gas Emissions from Ten-Well Pad	10,505 – 10,610	14,524 – 16,629	60	1,500	12,005 – 12,110	16,024 – 18,129
Estimated Post First-Year Annual Green House Gas Emissions from Ten-Well Project	18,784 (1,878/well)	19,076 (1,908/well)	1,470 (147/well)	36,750 (3,675/well)	55,534 (5,553/well)	55,826 (5,583/well)

Significant uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.25, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the "Published emission factors" and "Engineering calculations" options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that will be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.[73]

- Incomplete, unclear or faulty definitions of emission sources
- Natural variability of the process that produces the emissions

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

[73] American Petroleum Institute., *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-30, August 2009. Hhttp://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf

- Models, or equations, used to quantify emissions for the process or quantity under consideration

Nevertheless, while the results of potential GHG emissions presented in above Table 6.24 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO_2 and CH_4 emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Section 7.6, is a discussion of possible mitigation measures geared toward reducing GHGs, with emphasis on CH_4.

Table 6.16 - Emission Estimation Approaches – General Considerations[74]

Types of Approaches	General Considerations
Published emission factors	· Accounts for average operations or conditions · Simple to apply · Requires understanding and proper application of measurement units and underlying standard conditions · Accuracy depends on the representativeness of the factor relative to the actual emission source · Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	· Tailored to equipment-specific parameters · Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions · Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures · Accuracy depends on adjustment to actual fuel composition used on-site · Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	· Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	· Accuracy depends on simplifying assumptions that may be contained within the computer model methods · May require detailed input data to properly characterize process conditions · May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	· Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources · Care should be taken when correcting to represent the applicable standard conditions · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous[a] monitoring of emissions or parameters[b] for calculating emissions	· Accounts for operational and source specific conditions · Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters · Instrumentation not available for all GHGs or applicable to all sources · Equipment, operating, and maintenance costs must be considered for monitoring equipment

Footnotes and Sources:
[a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions.
[b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.

---

[74] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry*, p. 3-9, August 2009. Hhttp://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf

6.7 Centralized Flowback Water Surface Impoundments

The potential use of large centralized surface impoundments to hold flowback water as part of dilution and reuse system is described in Section 5.12.2.1. The potential impacts associated with use of such impoundments that are identified in several sections above and are summarized here.

Use of centralized surface impoundments and flowback water pipelines as part of a flowback water dilution and reuse system has environmental benefits, including reduced demand for fresh water, reduced truck traffic and reduced need for flowback water treatment and disposal. However, any proposal for their use requires that the potential impacts be recognized and mitigated through proper design, construction, operation, closure and regulatory oversight.

- Potential soil, wetland, surface water and groundwater contamination from spills, leaks or other failure of the impoundment to effectively contain fluid. This includes problems associated with liner or construction defects, unstable ballast or operations-related liner damage.

- Potential soil, wetland, surface water and groundwater contamination from spills or leaks of hoses or pipes used to convey flowback water to or from the centralized surface impoundment.

- Potential for personal injury, property damage or natural resource damage similar to that from dam failure if a breach occurs.

- Transfer of invasive plant species by machinery and equipment used to remove vegetation and soil.

- Consumption by waterfowl and other wildlife of contaminated plant material on the inside slopes of the impoundment.

- Emission of Hazardous Air Pollutants (HAPs) which could exceed ambient air thresholds 1,000 meters (3,300 feet) from the impoundment and could cause the impoundment to qualify as a major source of HAPs.

6.8 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to make the radioactive material more accessible to human contact or to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale.) Radium-226 is the radionuclide of greatest concern from the Marcellus.

Detection of elevated levels (multiple times background) of NORM in oil and gas drill sites in the North Sea and U.S. Gulf Coast and mid-continent areas in the 1980s led to concerns about health impacts on drill site workers and the general public where exploration and production equipment and wastes were disposed or recycled. The U.S. Environmental Protection Agency (USEPA) measured values of radioactivity ranging from 9,000 picocuries per liter (pCi/l) for produced water to >100,000 pCi/g (picocuries per gram) for pipe and tank scale. The annual general public and occupational radiation dose limits vary above estimated background levels of 300-400 millirem (mrem), depending on the agency of origin. The annual dose limits range from several tens to 5,000 mrem among the Nuclear Regulatory Commission (NRC), U.S. Department of Energy (USDOE), and USEPA. Additional components to the NORM issue are: 1) NORM is commonly measured in concentration units, either pCi/l or pCi/g, while health standards for all types of ionizing radiation are provided in dose equivalent units (mrem/yr) with no simple or universally accepted equivalence between these units; and 2) most states have not yet formally classified oil and gas drill rig personnel as occupational radiation workers.

Oil and gas NORM occurs in both liquid (produced waters), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the largest volume of NORM is in produced waters, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (scale) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also filter media from the treatment of production waters may concentrate NORM and require controls to limit radiation exposure to workers handling this material.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (see table below). Radon gas, the main human health concern from NORM, is produced by the decay of Radium-226, which occurs in the Uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Radionuclide Half-Lives

Radionuclide	Half-life	Mode of Decay
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of produced waters (>109 bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

6.9 Visual Impacts

Aesthetic impact occurs when there is a detrimental effect on the perceived beauty of a place or structure. Significant aesthetic impacts are those that may cause a diminishment of the public enjoyment and appreciation of an inventoried resource, or one that impairs the character or quality of such a place.

The requirement to assess impacts to visual resources was the subject of a topical response in the GEIS. The conclusion was that visual impacts from oil and gas drilling and completion activities are primarily minor and short-term, vary with topography, vegetation, and distance to viewer, and rarely trigger a need for site-specific comprehensive review or mitigating conditions such as limited drilling hours and camouflage or landscaping of the drill site. The Department's *Visual EAF Addendum* is available to conduct a comprehensive review of visual impacts when one is needed.[75]

The visual impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. They include drill site and access road clearing and grading, drill rig and equipment during the drilling phase, and production equipment if the well is viable. The 1992 GEIS stated that drill rigs vary in height from 30 feet for a small cable tool rig to 100 feet or greater for a large rotary, though the larger 100 foot rotary rigs are not commonly used in New York. By comparison, the rigs used for horizontal drilling could be 140 feet or greater and will have more supporting equipment. Additionally, the site clearing for the pad will increase from approximately two acres to approximately five acres. The most important difference, however, is in the duration of drilling and hydraulic fracturing. A horizontal well takes four to five weeks of 24 hours per day drilling to complete with an additional 3 to 5 days for the hydraulic fracture. This compares to the approximately one to two weeks or longer drill time as discussed in 1992. There was no mention of the time required for hydraulic fracturing in 1992.[76]

Multi-well pads will be slightly larger but the equipment used is often the same, resulting in similar visual issues as those associated with a single well pad. Based on industry response, a taller rig with a larger footprint and substructure, 170-foot total height, may be used for drilling consecutive wells on a pad. In other instances, smaller rigs may be used to drill the initial hole and conductor casing to just above the kick-off point. The larger rig would then be used for the final horizontal portion of the hole. Typically one or two wells are drilled and then the rig is removed. If the well(s) are viable, the rig is brought back and the remaining wells are drilled and

---

[75] Hhttp://www.dec.ny.gov/docs/permits_ej_operations_pdf/visualeaf.pdf

[76] NTC, pp. 15-16

stimulated. As industry gains confidence in the production of the play, there is the possibility that all wells on a pad would be drilled, stimulated and completed consecutively, reducing the time frame of the visual impact. The regulations require that all wells on a multi-well pad be drilled within three years of starting the first well.[77]

The benefit of the multi-well pad is that it decreases the number of pads on the landscape. Current regulations allow for one single well pad per 40-acre spacing unit, one multi-well pad per 640-acre spacing unit or various other configurations as described in Section 5.1.3.2. Use of multi-well pads will reduce the number of long term visual impacts that result from reclaimed pads and production equipment and reduce the overall amount of land disturbance. The drilling technology also provides flexibility in pad location allowing visual impacts, both long and short-term, to be minimized as much as possible.[78]

Long term visual impacts of a pad after the drilling phase are determined by whether the well is a producer or a dry hole. In either case, reclamation work must begin with closure of any on-site reserve pit within 45 days of cessation of drilling and stimulation. If the well is a dry hole, the entire site will be reclaimed with very little permanent visual impact unless the site had been heavily forested, in which case the drilling will leave a changed landscape until trees grow back. All that will remain at a producing gas well site is an assembly of wellhead valves and auxiliary equipment such as meters, a dehydrator, a gas-water separator, a brine tank and a small fire-suppression tank. Multi-well pads may have somewhat larger equipment to handle the increased production. The remainder of a producing well site will be reclaimed with current well pads leaving as much as three acres for production equipment compared to less than one acre for a single well, as discussed in 1992.[79]

For informational purposes, Photos 6.2 - 6.13 depict a variety of actual wellsites in New York developed since the publication of the GEIS to illustrate their appearance during different stages of operations.

[77] NTC, pp. 15-16

[78] NTC, pp. 15-16

[79] NTC, pp. 15-16

6.10 Noise [80]

In NYS-DEC Policy DEP-00-1, noise is defined as any loud, discordant or disagreeable sound or sounds. More commonly, in an environmental context, noise is defined simply as unwanted sound. The environmental effects of sound and human perceptions of sound can be described in terms of the following four characteristics:

1) Sound Pressure Level (SPL may also be designated by the symbol L_p), or perceived loudness as expressed in decibels (dB) or A-weighted decibel scale dB(A) which is weighted towards those portions of the frequency spectrum, between 20 and 20,000 Hertz, to which the human ear is most sensitive. Both measure sound pressure in the atmosphere.

2) Frequency (perceived as pitch), the rate at which a sound source vibrates or makes the air vibrate.

3) Duration i.e., recurring fluctuation in sound pressure or tone at an interval; sharp or startling noise at recurring interval; the temporal nature (continuous vs. intermittent) of sound.

4) Pure tone, which is comprised of a single frequency. Pure tones are relatively rare in nature but, if they do occur, they can be extremely annoying.

[80] NTC, pp. 7-11

Photo 6-1- Electric Generators, Active Drilling
Site: Source: NTC Consulting

To aid staff in its review of a potential noise impact, Program Policy DEP-00-1 identifies three major categories of noise sources;

1) Fixed equipment or process operations;

2) Mobile equipment or process operations; and,

3) Transport movements of products, raw material or waste.

On Page 3 of its Notice of Determination of Non-Significance for a well drilled in Chemung County in 2002, the Department found that "Impacts associated with noise during drilling are directly related to the distance from a receptor. Drilling operations involve various sources of noise. The primary sources of noise were determined to be as follows:[81]

1) *Air Compressors:* Air compressors are typically powered by diesel engines, and generate the highest degree of noise over the course of drilling operations. Air

[81] Pages 4-5 - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002).

compressors will be in operation virtually throughout the drilling of a well. However, the actual number of operating compressors will vary.

2) *Tubular Preparation and Cleaning:* Tubular preparation and cleaning is an operation that is conducted as drill pipe is placed into the wellbore. As tubulars are raised onto the drill floor, workers physically hammer the outside of the pipe to displace internal debris. This process, when conducted during the evening hours, seems to generate the most concern from adjacent landowners. While the decibel level is comparatively low, the acute nature of the noise is noticeable.

3) *Elevator Operation:* Elevators are used to move drill pipe and casing into and/or out of the wellbore. During drilling, elevators are used to add additional pipe to the drill string as the depth increases. Elevators are used when the drilling contractor is removing multiple sections of pipe from the well or placing drill pipe or casing into the wellbore. Elevator operation is not a constant activity and its duration is dependent on the depth of the well bore. The decibel level is low.

4) *Drill Pipe Connections:* As the depth of the well increases, the drilling contractor must connect additional pipe to the drill string. Most operators in the Appalachian Basins use a method known as "air-drilling." As the drill bit penetrates the rock the cuttings must be removed from the wellbore. Cuttings are removed by displacing pressurized air (from the air compressors discussed above) into the well bore. As the air is circulated back to the surface, it carries with it the rock cuttings. To connect additional pipe to the drill string, the operator will release the air pressure. It is the release of pressure that creates a noise impact.

5) *Noise Generated by Support of Equipment and Vehicles:* Similar to any construction operation, drill sites require the use of support equipment and vehicles. Specialized cement equipment and vehicles, water trucks and pumps, flatbed tractor trailers and delivery and employee vehicles are the most common forms of support machinery and vehicles. Noise generated from these sources is consistent with other road-based vehicles. Cementing equipment will generate additional noise during operations but this impact is typically short lived and is at levels below that of the compressors described above.

Noise associated with the above activities is temporary and end once drilling operations cease.[82]

The noise impacts associated with horizontal drilling and high volume hydraulic fracturing are, in general, similar to those addressed in the 1992 GEIS. Site preparation and access road building will have noise that is associated with a construction site, including noise from bulldozers, backhoes, and other types of construction equipment. The rigs and supporting equipment are somewhat larger than the commonly-used equipment described in 1992, but with

[82] Page 4, - Notice of Determination of Non-Significance – API# 31-015-22960-00, Permit 08828 (February 13, 2002).

the exception of specialized downhole tools, horizontal drilling is performed using the same equipment, technology and procedures as many wells that have been drilled in New York. The basic procedures described for hydraulic fracturing are also the same. Production phase well site equipment is very quiet with negligible impacts.

The largest difference with relation to noise impacts, however, is in the duration of drilling. A horizontal well takes four to five weeks of 24-hours-per-day drilling to complete. The 1992 GEIS anticipated that most wells drilled in New York with rotary rigs would be completed in less than one week, though drilling could extend two weeks or longer.

High volume hydraulic fracturing is also of a larger scale than the water-gel fracs addressed in 1992. These were described as requiring 20,000 to 80,000 gallons of water pumped into the well at pressures of 2,000 to 3,500 psi. The procedure for a typical horizontal well requires one to three million or more gallons of water with a maximum casing pressure from 10,000 to 11,000 psi. This volume and pressure will result in more pump and fluid handling noise than anticipated in 1992. The proposed process requires three to five days to complete. There was no mention of the time required for hydraulic fracturing in 1992.

There will also be significantly more trucking and associated noise involved with high volume hydraulic fracturing than was addressed in the 1992 GEIS. In addition to the trucks required for the rig and its associated equipment, trucks are used to bring in water for drilling and hydraulic fracturing, sand for proppant, and frac tanks if pits are not used. Trucks are also used for the removal of flowback for the site. Estimates of truck trips per well are as follows:

Drill Pad and Road Construction Equipment	10 - 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 - 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 - 50 Truckloads
Completion Rig	15 Truckloads
Completion Fluid and Materials	10 - 20 Truckloads
Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads

This level of trucking could have negative noise impacts for those living in close proximity to the well site and access road. Like other noise associated with drilling this is temporary. Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. Thus it is possible that someone living in close proximity to the pad will experience adverse noise impacts intermittently for up to three years.

The benefits of a multi-well pad are the reduced number of sites generating noise and, with the horizontal drilling technology, the flexibility to site the pad in the best location to mitigate the impacts. As described above and in more detail in Section 5.1.3.2, current regulations allow for one single well pad per 40-acre spacing unit, one multi-well pad per 640-acre spacing unit or various other combinations. This provides the potential for one multi-well pad to drain the same area that could contain up to 16 single well pads. With proper pad location and design the adverse noise impacts can be significantly reduced.

Multi-well pads also have the potential to greatly reduce the amount of trucking and associated noise in an area. Rigs and equipment may only need to be delivered and removed one time for the drilling and stimulation of all of the wells on the pad. Reducing the number of truck trips required for frac water is also possible by reusing water for multiple frac jobs. In certain instances it also may be economically viable to transport water via pipeline to a multi-well pad.

6.11 Road Use [83]

While the trucking for site preparation, rig, equipment, materials and supplies is similar for horizontal drilling to what was anticipated in 1992**,** the water requirement of high volume hydraulic fracturing could lead to significantly more truck traffic than was discussed in the GEIS. It is estimated that each horizontal well will need between one to three million gallons or more of water for stimulation. Estimates of truck trips per well are as follows:

Drill Pad and Road Construction Equipment	10 - 45 Truckloads
Drilling Rig	30 Truckloads
Drilling Fluid and Materials	25 - 50 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	25 - 50 Truckloads
Completion Rig	15 Truckloads
Completion Fluid and Materials	10 - 20 Truckloads

[83] NTC, pp. 22-23

Completion Equipment (pipe, wellhead)	5 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	150 - 200 Truckloads
Hydraulic Fracture Water	400 - 600 Tanker Trucks
Hydraulic Fracture Sand Trucks	20 - 25 Trucks
Flow Back Water Removal	200 - 300 Truckloads

As can be seen, trucking of hydraulic fracture equipment, water, sand and flow back removal is over 80% of the total. This trucking will take place in weeks-long periods before and after the hydraulic fracture.

Multi-well pads have the potential to reduce some of the total trucking in an area. Consecutively drilling and stimulating multiple wells from one pad will eliminate the trucking of equipment for single well pad to single well pad. Reduced water trucking is also a possibility. There is the potential to reuse flow back water for other fracturing operations. The centralized location of water impoundments may also make it economically viable for water to be brought in by pipeline or means other than trucking.

As discussed in 1992 regarding conventional vertical wells, trucking during the long term production life of a horizontally drilled single or multi-well pad will be insignificant.

6.12 Community Character Impacts[84]

Many of the community character impacts associated with horizontal drilling and high volume hydraulic fracturing are the same as those addressed in the 1992 GEIS, and no further mitigation measures are required. These include:

1) The possibility of injury to humans or the environment if site access is not properly restricted to prevent accidents or vandalism.

2) Temporal noise or visual impacts.

3) Temporary land use conflicts are identified in the discussion of unavoidable impacts.

4) Potential positive impacts from gas development identified including the availability of clean burning natural gas, generation of State and local taxes, revenues to landowners, and the multiplier effects of private investment in the State.

[84] NTC, pp. 21-23

5) Increased human activity and access to remote areas provided by the access roads as secondary impacts, with the former more intense during the drilling phase.

Community impacts related to horizontal drilling and high volume hydraulic fracturing needing further discussion include trucking, land use changes and environmental justice. Trucking is discussed in Section 6.11 of this Supplement.

6.12.1 Land Use Patterns

The spacing unit density for vertical shale wells is the same as discussed and anticipated in 1992. This density has been experienced in New York in Chautauqua and Seneca Counties without significant changes in land use patterns. The new drilling technology should not be expected to change the 1992 GEIS findings.

As mentioned previously, there is the option, not discussed in 1992, to use multi-well pads with a 640-acre spacing unit. This option has the potential to create less of an impact on community character by significantly reducing the total area required for roadways, pipelines, and well pads. While the pad will be larger and the activity at the location will be longer than for single well pads, the fewer total sites will reduce the cumulative changes to the host community, and should minimize loss or fragmentation of habitats, agricultural areas, forested areas, disruptions to scenic view sheds, and the like.

6.12.2 Environmental Justice

This is an issue that is not discussed in the 1992 GEIS. The United States Environmental Protection Agency definition is as follows: “Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.” The SGEIS/SEQRA process provides opportunity for public input and the resulting permitting procedures will apply state wide and provide equal protection to all communities and persons in New York. The location of drilling will be determined by where the gas is located and the resulting revenues will benefit the land owners and the surrounding community.

6.13 Cumulative Impacts[85]

Cumulative impacts are the effects of two or more single projects considered together. Adverse cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. The 1992 GEIS defines the project scope as an individual well with a limited discussion of cumulative impacts. Chapter 18 discusses the positive economic impacts of gas development for municipalities and for the entire State. Additionally, as an unavoidable adverse impact it states: "Though the potential for severe negative impacts from any one site is low. When all activities in the State are considered together, the potential for negative impacts on water quality, land use, endangered species and sensitive habitats increases significantly."

Cumulative impacts will be discussed from two perspectives;

1) **Site Specific** cumulative impacts beyond those considered in the 1992 GEIS resulting from multi-well pads and
2) **Regional** impacts which may be experienced as a result of gas development.

6.13.1 Site-Specific Cumulative Impacts

The potential for site specific cumulative impacts as a result of multi-well pads, while real, is easily quantified and can be adequately addressed during the application review process. General areas of concern with regard to noise, visual, and community character issues are the same as those of individual well pads. While the pads may be slightly larger than those used for single wells, the significant impacts are due to the cumulative time and trucking necessary to drill and stimulate each individual well.

When reviewed in 1992, it was assumed that a well pad would be constructed, drilled and reclaimed in a period measured in a few months, with the most significant activity being measured in one or two weeks for the majority of wells. By comparison, a horizontal well takes four to five weeks of 24-hour-per-day drilling with an additional three to five days for the

[85] NTC, pp. 26-31

hydraulic fracture. This duration will be required for each well, with industry indicating that it is common for six to eight wells to be drilled on a multi-well pad. Typically, one or two wells are drilled and stimulated and then the equipment is removed. If the well(s) are economically viable, the equipment is brought back and the remaining wells drilled and stimulated. Current regulations require that all wells on a multi-well pad be drilled within three years of starting the first well. As industry gains confidence in the production of the play, there is the possibility that all wells on a pad would be drilled, stimulated and completed consecutively. This concept will shorten the time frame of noise generation and eliminate the noise generated by one rig disassembly/reassembly cycle.

The trucking requirements for rigging and equipment will not be significantly greater than for a single well pad, especially if all wells are drilled consecutively. Water and materials requirements, however, will greatly increase the amount of trucking to a multi-well pad compared to a single well pad. Estimates of truck trips per multi-well pad are as follows (assumes two rig and equipment deliveries and 8 wells):

Drill Pad and Road Construction Equipment	10 – 45 Truckloads
Drilling Rig	60 Truckloads
Drilling Fluid and Materials	200 – 400 Truckloads
Drilling Equipment (casing, drill pipe, etc.)	200 – 400 Truckloads
Completion Rig	30 Truckloads
Completion Fluid and Materials	80 – 160 Truckloads
Completion Equipment – (pipe, wellhead)	10 Truckloads
Hydraulic Fracture Equipment (pump trucks, tanks)	300 – 400 Truckloads
Hydraulic Fracture Water	3,200 – 4,800 Tanker Trucks
Hydraulic Fracture Sand	160 – 200 Trucks
Flow Back Water Removal	1,600 – 2,400 Tanker Trucks

As can be seen, the vast majority of trucking is involved in delivering water and removing flow back. Multiple wells in the same location provide the potential to reduce this amount of trucking by reusing flow back water for the stimulation of other wells on the same pad. The centralized location of water impoundments may also make it economically viable to transport water via pipeline or rail in certain instances.

In the production phase, the operations at multi-well pads are similar to what was addressed in 1992. There will be a small amount of equipment, including valves, meters, dehydrators and tanks remaining on site, which may be slightly larger than what is used for single wells but is still minor and is quiet in operation. The reclamation procedures are the same as for single well pads, however, there will be more area left for production equipment and activities. It is anticipated that a multi-well pad will require up to three acres compared to one acre or less as discussed in 1992.

6.13.1.2 Site-Specific Cumulative Impacts Conclusions

A single multi-well pad on a 640-acre spacing unit will drain the same area that could contain up to 16 single well pads. As discussed earlier, the pad will be larger, the area left for production will be larger and, the duration of drilling and stimulating activities on the pad will be longer. The decrease in the number of drilling sites reduces the regional long term and short-term cumulative impacts.

6.13.2 Regional Cumulative Impacts

The level of impact on a regional basis will be determined by the amount of development and the rate at which it occurs. Accurately estimating this is inherently difficult due to the wide and variable range of the resource, rig, equipment and crew availability, permitting and oversight capacity, leasing, and most importantly, economic factors. This holds true regardless of the type of drilling and stimulation utilized. Historically in New York, and in other plays around the country, development has occurred in a sequential manner over years with development activity concentrated in one area then moving on with previously drilled sites fully or partially reclaimed as new sites are drilled. As with the development addressed in 1992, once drilling and stimulation activities are completed and the sites have been reclaimed, the long term impact will consist of widely spaced and partially re-vegetated production sites and fully reclaimed plugged and abandoned well sites.

The statewide spacing regulations for vertical shale wells of one single well pad per 40-acre spacing unit will allow no greater density for horizontal drilling with high volume hydraulic fracturing than is allowed for conventional drilling techniques. This density was anticipated in 1992 and areas of New York, including Chautauqua, Cayuga and Seneca Counties, have experienced drilling at this level without significant negative impacts to agriculture, tourism, other land uses or any of the topics discussed in this report.

As discussed earlier, the density for multi-well pads, one per 640-acre spacing unit, is significantly less than for single well pads, reducing the total number of disturbances to the landscape. While multi-well pads will be slightly larger than single well pads the reduction in number will lead to a substantial decrease in the total amount of disturbed acreage, providing additional mitigation for long term visual and land use impacts on a regional basis. The following table provides an example for a 10 square mile area (i.e., 6,400 acres), completely drilled, comparing the 640 acre spacing option with multi-well pads and horizontal drilling to the 40 acre spacing option with single well pads and vertical drilling.

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

As can be seen, multi-well pads will significantly decrease the amount of disturbance on a regional basis in all phases of development. The reduction in sites should also allow for more resources to be devoted to proper siting and design of the pad and to mitigating the short-term impacts that occur during the drilling and stimulation phase.

6.13.2.1 Rate of Development and Thresholds

In response to questioning, a representative for one company estimated a peak activity for all of industry at 2,000 wells per year ± 25% in the New York Marcellus play. Other companies did not provide an estimate. By comparison, in Pennsylvania, where the reservoir is much more widespread, permitting activity is ongoing.

Year	**Marcellus Permits Issued**
2007	99
2008	510
2009 (Through 8/31)	1127

SOURCE: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG09.htm

Recent development in the Barnett play in Texas, which utilizes the same horizontal drilling with high volume hydraulic fracturing that will be used in New York, has occurred at a rapid rate over the last decade. It is an approximately 4,000 square mile play located in and around the Dallas – Fort Worth area. In the eight-year period from 2002 to 2008 approximately 10,500 wells were drilled.

The final scoping document summarizes the challenge of forecasting rates of development as follows:

> The number of wells which will ultimately be drilled cannot be known in advance, in large part because the productivity of any particular formation at any given location and depth is not known until drilling occurs. Changes in the market and other economic conditions also have an impact on whether and how quickly individual wells are drilled.[86]

Additional research has identified that "Experience developing shale gas plays in the past 20 years has demonstrated that every shale play is unique."[87] Each individual play has been defined, tested and expanded based on an understanding of the resource distribution, natural fracture patterns, and limitations of the reservoir, and each play has required solutions to problems and issues required for commercial production. Many of these problems and solutions are unique to the play.[88]

The timing, rate and pattern of development, on either a statewide or local basis, are very difficult to accurately predict.[89] As detailed in Section 2.1.6 of the Final Scoping Document, "overall site density is not likely to be greater than was experienced and envisioned when the GEIS and its Findings were finalized and certified in 1992."

The rate of development cannot be predicted with any certainty based on the factors cited above and in the Final Scoping Document. Nor is it possible to define the threshold at which development results in adverse noise, visual and community character impacts. Some people will feel that one drilling rig on the landscape is too many, while others will find the changes in

86 Final Scoping Document (Page 39)

87 Fractured Shale Gas Potential in New York (Page 1)

88 Ibid

89 Final Scoping Document (Page 39)

the landscape inoffensive and will want full development of the resource as quickly as possible. There is no way to objectify these inherently subjective perspectives. As a result, there is no supportable basis on which to set a limit on the rate of development of the Marcellus and other low-permeability gas reservoirs.

It is certain that widespread development of the Marcellus shale as described in this document will have community impacts that will change the quality of life in the affected areas in the short term. For purposes of this review, however, there is no sound basis for an administrative determination limiting the shale development on the basis of those changes at this time. Accordingly, any limitation on development, aside from the mitigation measures discussed in the next chapter, is more appropriately considered in the context of policy making, primarily at the local level, outside of the SGEIS.

6.14 Seismicity[90]

Economic development of natural gas from low permeability formations requires the target formation to be hydraulically fractured to increase the rock permeability and expose more rock surface to release the gas trapped within the rock. The hydraulic fracturing process fractures the rock by controlled application of hydraulic pressure in the wellbore. The direction and length of the fractures are managed by carefully controlling the applied pressure during the hydraulic fracturing process.

The release of energy during hydraulic fracturing produces seismic pressure waves in the subsurface. Microseismic monitoring commonly is performed to evaluate the progress of hydraulic fracturing and adjust the process, if necessary, to limit the direction and length of the induced fractures. Chapter 4 of this Supplement presents background seismic information for New York. Concerns associated with the seismic events produced during hydraulic fracturing are discussed below.

[90] Alpha, Section 7; discussion was provided for NYSERDA by Alpha Environmental, Inc., and Alpha's references are included for informational purposes.

6.14.1 Hydraulic Fracturing-Induced Seismicity

Seismic events that occur as a result of injecting fluids into the ground are termed “induced.” There are two types of induced seismic events that may be triggered as a result of hydraulic fracturing. The first is energy released by the physical process of fracturing the rock which creates microseismic events that are detectable only with very sensitive monitoring equipment. Information collected during the microseismic events is used to evaluate the extent of fracturing and to guide the hydraulic fracturing process. This type of microseismic event is a normal part of the hydraulic fracturing process used in the development of both horizontal and vertical oil and gas wells, and by the water well industry.

The second type of induced seismicity is fluid injection of any kind, including hydraulic fracturing, which can trigger seismic events ranging from imperceptible microseismic, to small-scale, “felt” events, if the injected fluid reaches an existing geologic fault. A “felt” seismic event is when earth movement associated with the event is discernable by humans at the ground surface. Hydraulic fracturing produces microseismic events, but different injection processes, such as waste disposal injection or long term injection for enhanced geothermal, may induce events that can be felt, as discussed in the following section. Induced seismic events can be reduced by engineering design and by avoiding existing fault zones.

6.14.1.1 Background

Hydraulic fracturing consists of injecting fluid into a wellbore at a pressure sufficient to fracture the rock within a designed distance from the wellbore. Other processes where fluid is injected into the ground include deep well fluid disposal, fracturing for enhanced geothermal wells, solution mining and hydraulic fracturing to improve the yield of a water supply well. The similar aspect of these methods is that fluid is injected into the ground to fracture the rock; however, each method also has distinct and important differences.

There are ongoing and past studies that have investigated small, felt, seismic events that may have been induced by injection of fluids in deep disposal wells. These small seismic events are not the same as the microseismic events triggered by hydraulic fracturing that can only be detected with the most sensitive monitoring equipment. The processes that induce seismicity in both cases are very different.

Deep well injection is a disposal technology which involves liquid waste being pumped under moderate to high pressure, several thousand feet into the subsurface, into highly saline, permeable injection zones that are confined by more shallow, impermeable strata (FRTR, August 12, 2009). The goal of deep well injection is to store the liquids in the confined formation(s) permanently.

Carbon sequestration is also a type of deep well injection, but the carbon dioxide emissions from a large source are compressed to a near liquid state. Both carbon sequestration and liquid waste injection can induce seismic activity. Induced seismic events caused by deep well fluid injection are typically less than a magnitude 3.0 and are too small to be felt or to cause damage. Rarely, fluid injection induces seismic events with moderate magnitudes, between 3.5 and 5.5, that can be felt and may cause damage. Most of these events have been investigated in detail and have been shown to be connected to circumstances that can be avoided through proper site selection (avoiding fault zones) and injection design (Foxall and Friedmann, 2008).

Hydraulic fracturing also has been used in association with enhanced geothermal wells to increase the permeability of the host rock. Enhanced geothermal wells are drilled to depths of many thousands of feet where water is injected and heated naturally by the earth. The rock at the target depth is fractured to allow a greater volume of water to be re-circulated and heated. Recent geothermal drilling for commercial energy-producing geothermal projects have focused on hot, dry, rocks as the source of geothermal energy (Duffield, 2003). The geologic conditions and rock types for these geothermal projects are in contrast to the shallower sedimentary rocks targeted for natural gas development. The methods used to fracture the igneous rock for geothermal projects involve high pressure applied over a period of many days or weeks (Florentin 2007 and Geoscience Australia, 2009). These methods differ substantially from the lower pressures and short durations used for natural gas well hydraulic fracturing.

Hydraulic fracturing is a different process that involves injecting fluid under higher pressure for shorter periods than the pressure level maintained in a fluid disposal well. A horizontal well is fractured in stages so that the pressure is repeatedly increased and released over a short period of time necessary to fracture the rock. The subsurface pressures for hydraulic fracturing are sustained typically for one or two days to stimulate a single well, or for approximately two weeks at a multi-well pad. The seismic activity induced by hydraulic fracturing is only detectable at the surface by very sensitive equipment.

Avoiding pre-existing fault zones minimizes the possibility of triggering movement along a fault through hydraulic fracturing. It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing. Generally, operators will avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process. The presence of faults also potentially reduces the optimal recovery of gas and the economic viability of a well or wells.

Injecting fluid into the subsurface can trigger shear slip on bedding planes or natural fractures resulting in microseismic events. Fluid injection can temporarily increase the stress and pore pressure within a geologic formation. Tensile stresses are formed at each fracture tip, creating shear stress (Pinnacle; "FracSeis;" August 11, 2009). The increases in pressure and stress reduce the normal effective stress acting on existing fault, bedding, or fracture planes. Shear stress then overcomes frictional resistance along the planes, causing the slippage (Bou-Rabee and Nur, 2002). The way in which these microseismic events are generated is different than the way in which microseisms occur from the energy release when rock is fractured during hydraulic fracturing.

The amount of displacement along a plane that is caused by hydraulic fracturing determines the resultant microseism's amplitude. The energy of one of these events is several orders of magnitude less than that of the smallest earthquake that a human can feel (Pinnacle; "Microseismic;" August 11, 2009). The smallest measurable seismic events are typically between 1.0 and 2.0 magnitude. In contrast, seismic events with magnitude 3.0 are typically large enough to be felt by people. Many induced microseisms have a negative value on the MMS. Pinnacle Technologies, Inc. has determined that the characteristic frequencies of microseisms are between 200 and 2,000 Hertz; these are high-frequency events relative to typical seismic data. These small magnitude events are monitored using extremely sensitive instruments that are positioned at the fracture depth in an offset wellbore or in the treatment well (Pinnacle; "Microseismic;" August 11, 2009). The microseisms from hydraulic fracturing can barely be measured at ground surface by the most sensitive instruments (Sharma, personal communication, August 7, 2009).

There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing. Nonetheless, operators monitor the hydraulic fracturing process to optimize the results for successful gas recovery. It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process.

The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments. Multiple receivers on a wireline array are placed in one or more offset borings (new, unperforated well(s) or older well(s) with production isolated) or in the treatment well to detect microseisms and to monitor the hydraulic fracturing process. The microseism locations are triangulated using the arrival times of the various p- and s-waves with the receivers in several wells, and using the formation velocities to determine the location of the microseisms. A multi-level vertical array of receivers is used if only one offset observation well is available. The induced fracture is interpreted to lie within the envelope of mapped microseisms (Pinnacle; "FracSeis;" August 11, 2009).

Data requirements for seismic monitoring of a hydraulic fracturing treatment include formation velocities (from a dipole sonic log or cross-well tomogram), well surface and deviation surveys, and a source shot in the treatment well to check receiver orientations, formation velocities and test capabilities. Receiver spacing is selected so that the total aperture of the array is about half the distance between the two wells. At least one receiver should be in the treatment zone, with another located above and one below this zone. Maximum observation distances for microseisms should be within approximately 2500 ft of the treatment well; the distance is dependent upon formation properties and background noise level (Pinnacle; "FracSeis;" August 11, 2009).

6.14.1.2 Recent Investigations and Studies

Hydraulic fracturing has been used by oil and gas companies to stimulate production of vertical wells in New York State since the 1950s. Despite this long history, there are no records of induced seismicity caused by hydraulic fracturing in New York State. The only induced seismicity studies that have taken place in New York State are related to seismicity suspected to have been caused by waste fluid disposal by injection and a mine collapse, as identified in Section 4.5.4. The seismic events induced at the Dale Brine Field (Section 4.5.4) were the result of the injection of fluids for extended periods of time at high pressure for the purpose of salt solution mining. This process is significantly different from the hydraulic fracturing process that will be undertaken for developing the Marcellus and other low permeability shales in New York.

Gas producers in Texas have been using horizontal drilling and high-volume hydraulic fracturing to stimulate gas production in the Barnett Shale for the last decade. The Barnett is geologically similar to the Marcellus, but is found at a greater depth; it is a deep shale with gas stored in unconnected pore spaces and adsorbed to the shale matrix. High-volume hydraulic fracturing allows recovery of the gas from the Barnett to be economically feasible. The horizontal drilling and high-volume hydraulic fracturing methods used for the Barnett shale play are similar to those that would be used in New York State to develop the Marcellus, Utica, and other gas bearing shales.

Alpha contacted several researchers and geologists who are knowledgeable about seismic activity in New York and Texas, including:

- Mr. John Armbruster, Staff Associate, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Cliff Frohlich, Associate Director of the Texas Institute for Geophysics, The University of Texas at Austin
- Dr. Won-Young Kim, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Mr. Eric Potter, Associate Director of the Texas Bureau of Economic Geology, The University of Texas at Austin
- Mr. Leonardo Seeber, Doherty Senior Research Scientist, Lamont-Doherty Earth Observatory, Columbia University
- Dr. Mukul Sharma, Professor of Petroleum and Geosystems Engineering, The University of Texas at Austin
- Dr. Brian Stump, Albritton Professor, Southern Methodist University

None of these researchers have knowledge of any seismic events that could be explicitly related to hydraulic fracturing in a shale gas well. Mr. Eric Potter stated that approximately 12,500 wells in the Barnett play and several thousand wells in the East Texas Basin (which target tight gas sands) have been stimulated using hydraulic fracturing in the last decade, and there have been no documented connections between wells being fractured hydraulically and felt quakes (personal communication, August 9, 2009). Dr. Mukul Sharma confirmed that microseismic events associated with hydraulic fracturing can only be detected using very sensitive instruments (personal communication, August 7, 2009).

The Bureau of Geology, the University of Texas' Institute of Geophysics, and Southern Methodist University are planning to study earthquakes measured in the vicinity of the Dallas–Fort Worth (DFW) area, and Cleburne, Texas, that appear to be associated with salt water disposal wells, and oil and gas wells. The largest quakes in both areas were magnitudes of 3.3, and more than 100 earthquakes with magnitudes greater than 1.5 have been recorded in the DFW area in 2008 and 2009. There is considerable oil and gas drilling and deep brine disposal wells in the area and a small fault extends beneath the DFW area. Dr. Frohlich recently stated that "[i]t's always hard to attribute a cause to an earthquake with absolute certainty." Dr. Frohlich has two manuscripts in preparation with Southern Methodist University describing the analysis of the DFW activity and the relationship with gas production activities (personal communication, August 4 and 10, 2009). Neither of these manuscripts was available before this document was completed. Nonetheless, information posted online by Southern Methodist University (SMU, 2009) states that the research suggests that the earthquakes seem to have been caused by injections associated with a deep brine disposal well, and not with hydraulic fracturing operations.

6.14.1.3 Correlations between New York and Texas

The gas plays of interest, the Marcellus and Utica shales in New York and the Barnett shale in Texas, are relatively deep, low permeability, gas shales deposited during the Paleozoic Era. Horizontal drilling and high-volume hydraulic fracturing methods are required for successful, economical gas production. The Marcellus shale was deposited during the early Devonian, and the slightly younger Barnett was deposited during the late Mississippian. The depth of the Marcellus in New York ranges from exposure at the ground surface in some locations in the northern Finger Lakes area to 7,000 feet or more below the ground surface at the Pennsylvania border in the Delaware River valley. The depth of the Utica shale in New York ranges from exposure at the ground surface along the southern Adirondacks to more than 10,000 feet along the New York Pennsylvania border.

Conditions for economic gas recovery likely are present only in portions of the Marcellus and Utica members, as described in Chapter 4. The thickness of the Marcellus and Utica in New York ranges from less than 50 feet in the southwestern portion of the state to approximately 250 feet at the south-central border. The Barnett shale is 5,000 to 8,000 feet below the ground surface and 100 to 500 feet thick (Halliburton; August 12, 2009). It is estimated that the entire Marcellus shale may hold between 168 and 516 trillion cubic feet of gas; in contrast, the Barnett has in-place gas reserves of approximately 26.2 trillion cubic feet (USGS, 2009A) and covers approximately 4 million acres.

The only known induced seismicity associated with the stimulation of the Barnett wells are microseisms that are monitored with downhole transducers. These small-magnitude events triggered by the fluid pressure provide data to the operators to monitor and improve the fracturing operation and maximize gas production. The hydraulic fracturing and monitoring operations in the Barnett have provided operators with considerable experience with conditions similar to those that will be encountered in New York State. Based on the similarity of conditions, similar results are anticipated for New York State; that is, the microseismic events will be unfelt at the surface and no damage will result from the induced microseisms. Operators are likely to monitor the seismic activity in New York, as in Texas, to optimize the hydraulic fracturing methods and results.

6.14.1.4 Affects of Seismicity on Wellbore Integrity

Wells are designed to withstand deformation from seismic activity. The steel casings used in modern wells are flexible and are designed to deform to prevent rupture. The casings can withstand distortions much larger than those caused by earthquakes, except for those very close to an earthquake epicenter. The magnitude 6.8 earthquake event in 1983 that occurred in Coalinga, California, damaged only 14 of the 1,725 nearby active oilfield wells, and the energy released by this event was thousands of times greater than the microseismic events resulting from hydraulic fracturing. Earthquake-damaged wells can often be re-completed. Wells that cannot be repaired are plugged and abandoned (Foxall and Friedmann, 2008). Induced seismicity from hydraulic fracturing is of such small magnitude that it is not expected to have any effect on wellbore integrity.

6.14.2 Summary of Potential Seismicity Impacts

The issues associated with seismicity related to hydraulic fracturing addressed herein include seismic events generated from the physical fracturing of the rock, and possible seismic events produced when fluids are injected into existing faults.

The possibility of fluids injected during hydraulic fracturing the Marcellus or Utica shales reaching a nearby fault and triggering a seismic event are remote for several reasons. The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica shales. Similarly, the paucity of historic seismic events and the low seismic risk level in the fairways for these shales indicates that geologic conditions generally are stable in these areas. By definition, faults are planes or zones of broken or fractured rock in the subsurface. The geologic conditions associated with a fault generally are unfavorable for hydraulic fracturing and economical production of natural gas. As a result, operators typically endeavor to avoid faults for both practical and economic considerations. It is prudent for an applicant for a drilling permit to evaluate and identify known, significant, mapped, faults within the area of effect of hydraulic fracturing and to present such information in the drilling permit application. It is Alpha's opinion that an independent pre-drilling seismic survey probably is unnecessary in most cases because of the relatively low level of seismic risk in the fairways of the Marcellus and Utica shales. Additional evaluation or monitoring may be necessary if hydraulic fracturing fluids might reach a known, significant, mapped fault, such as the Clarendon-Linden fault system.

Recent research has been performed to investigate induced seismicity in an area of active hydraulic fracturing for natural gas development near Fort Worth, Texas. Studies also were performed to evaluate the cause of the earthquakes associated with the solution mining activity near the Clarendon-Linden fault system near Dale, N.Y. in 1971. The studies indicated that the likely cause of the earthquakes was the injection of fluid for brine disposal for the incidents in

Texas, and the injection of fluid for solution mining for the incidents in Dale, N.Y. The studies in Texas also indicate that hydraulic fracturing is not likely the source of the earthquakes.

The hydraulic fracturing methods used for enhanced geothermal energy projects are appreciably different than those used for natural gas hydraulic fracturing. Induced seismicity associated with geothermal energy projects occurs because the hydraulic fracturing is performed at greater depths, within different geologic conditions, at higher pressures, and for substantially longer durations compared with the methods used for natural gas hydraulic fracturing.

There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed in preparing this discussion indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells.

Seismic monitoring by the operators is performed to evaluate, adjust, and optimize the hydraulic fracturing process. Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude. The existing and well-established seismic monitoring network in New York is sufficient to document the locations of larger-scale seismic events and will continue to provide additional data to monitor and evaluate the likely sources of seismic events that are felt.

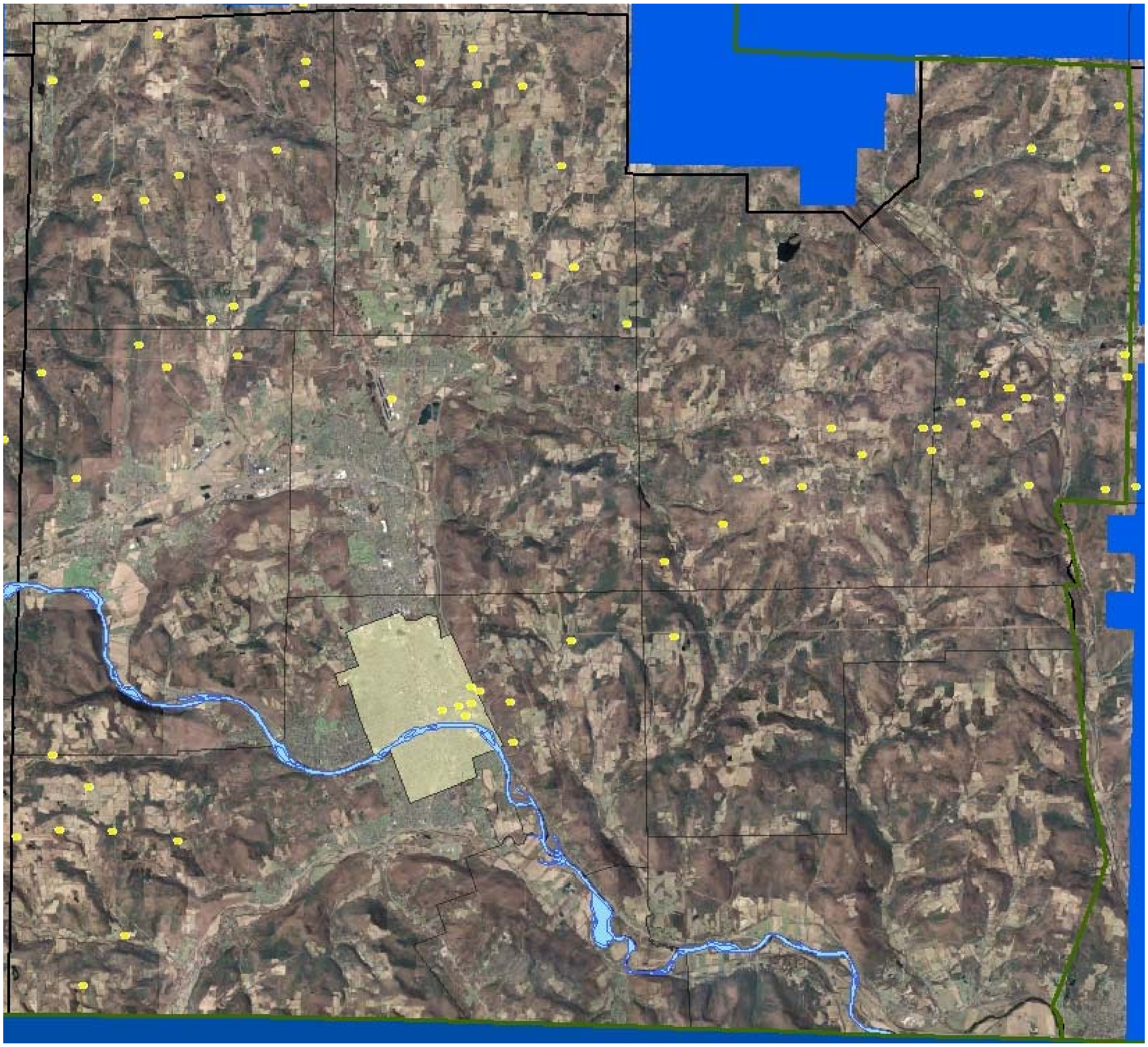
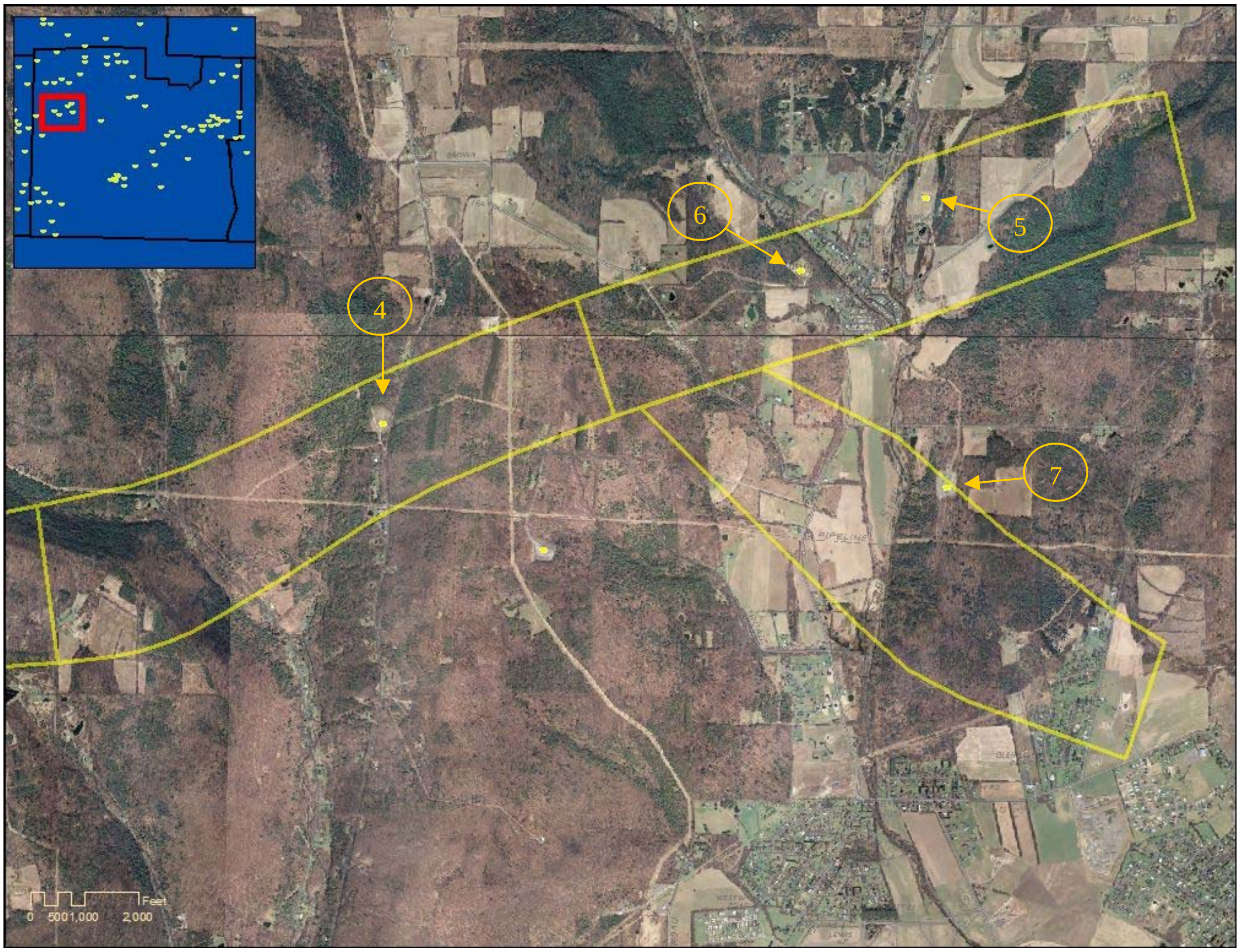


Photo 6.2 The following series of photos shows Trenton-Black River wells in Chemung County. These wells are substantially deeper than Medina wells, and are typically drilled on 640 acre units. Although the units and well pads typically contain one well, the size of the well units and pads is closer to that expected for multi-well Marcellus pads. Unlike expected Marcellus wells, Trenton-Black River wells target geologic features that are typically narrow and long. Nevertheless, photos of sections of Trenton-Black River fields provide an idea of the area of well pads within producing units.

The above photo of Chemung County shows Trenton-Black River wells and also historical wells that targeted other formations. Most of the clearings visible in this photo are agricultural fields.

Photo 6.3 The Quackenbush Hill Field is a Trenton-Black River field that runs from eastern Steuben County to north-west Chemung County. The discovery well for the field was drilled in 2000. The above map shows five wells in the eastern end of the field. Note the relative proportion of well pads to area of entire well units. We unit sizes shown are approximately 640 acres, similar to expected Marcellus Shale multi-well pad units.



Photos 6.4 Well #4 (Hole number 22853) was a vertical completed in February 2001 at a total vertical depth of 9,682 feet. The drill site disturbed area was approximately 3.5 acres. The site was subsequently reclaimed to a fenced area of approximately 0.35 acres for production equipment. Because this is a single-well unit, it contains fewer tanks and other equipment than a Marcellus multi-well pad. The surface within a T-BR well fenced area is typically covered with gravel.

Rhodes 1322 11/13/2001

Rhodes 1322 5/6/2009

Photos 6.5 Well #5 (Hole number 22916) was completed as a directional well in 2002. Unit size is 636 acres. Total drill pad disturbed area was approximately 3 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Gregory #1446A 12/27/2001

Gregory #1446A 5/6/2009

Photo 6.6 Well #6 (Hole number 23820) was drilled as a horizontal infill well in 2006 in the same unit as Well #6. Total drill pad disturbed area was approximately 3.1 acres, which has been reclaimed to a fenced area of approximately 0.4 acres.

Schwingel #2 5/6/2009

Photos 6.7 Well #7 (Hole number 23134) was completed as a horizontal well in 2004 to a vertical depth of 9,695 and a total drilled depth of 12,050 feet Well unit size is 624 acres. The drill pad disturbed area was approximately 4.2 acres which has been reclaimed to a gravel pad of approximately 1.3 acres of which approximately 0.5 acres is fenced for equipment.

Soderblom #1 8/19/2004

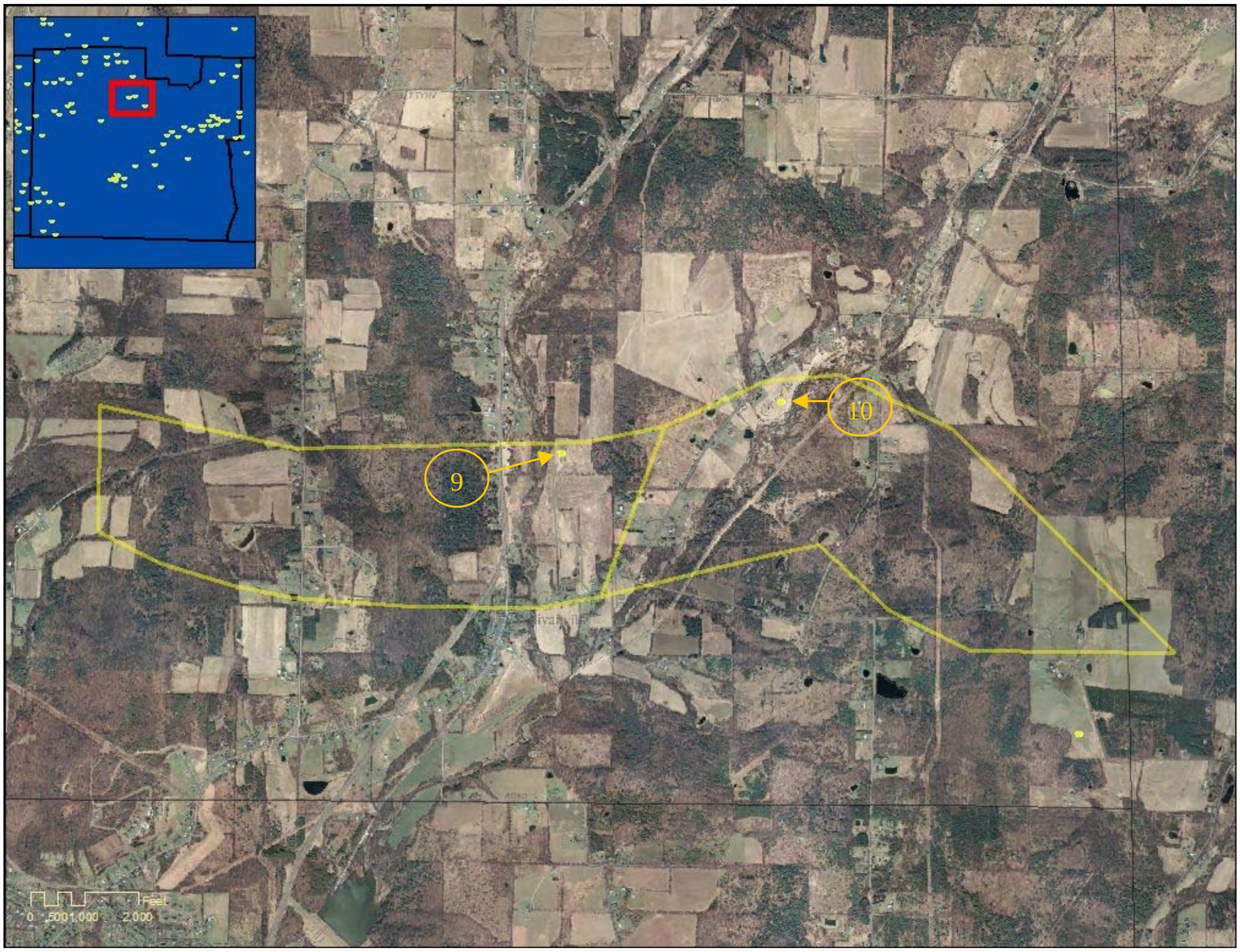
Soderblom #1 8/19/2004

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Soderblom #1 5/6/2009

Photo 6.8 This photo shows two Trenton-Black River wells in north-central Chemung County. The two units were established as separate natural gas fields, the Veteran Hill Field and the Brick House Field.



Photos 6.9 Well #9 (Hole number 23228) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a total vertical depth of 9,461 and a total drilled depth of 12,550 feet. The well unit is approximately 622 acres.

Little 1 10/6/2005

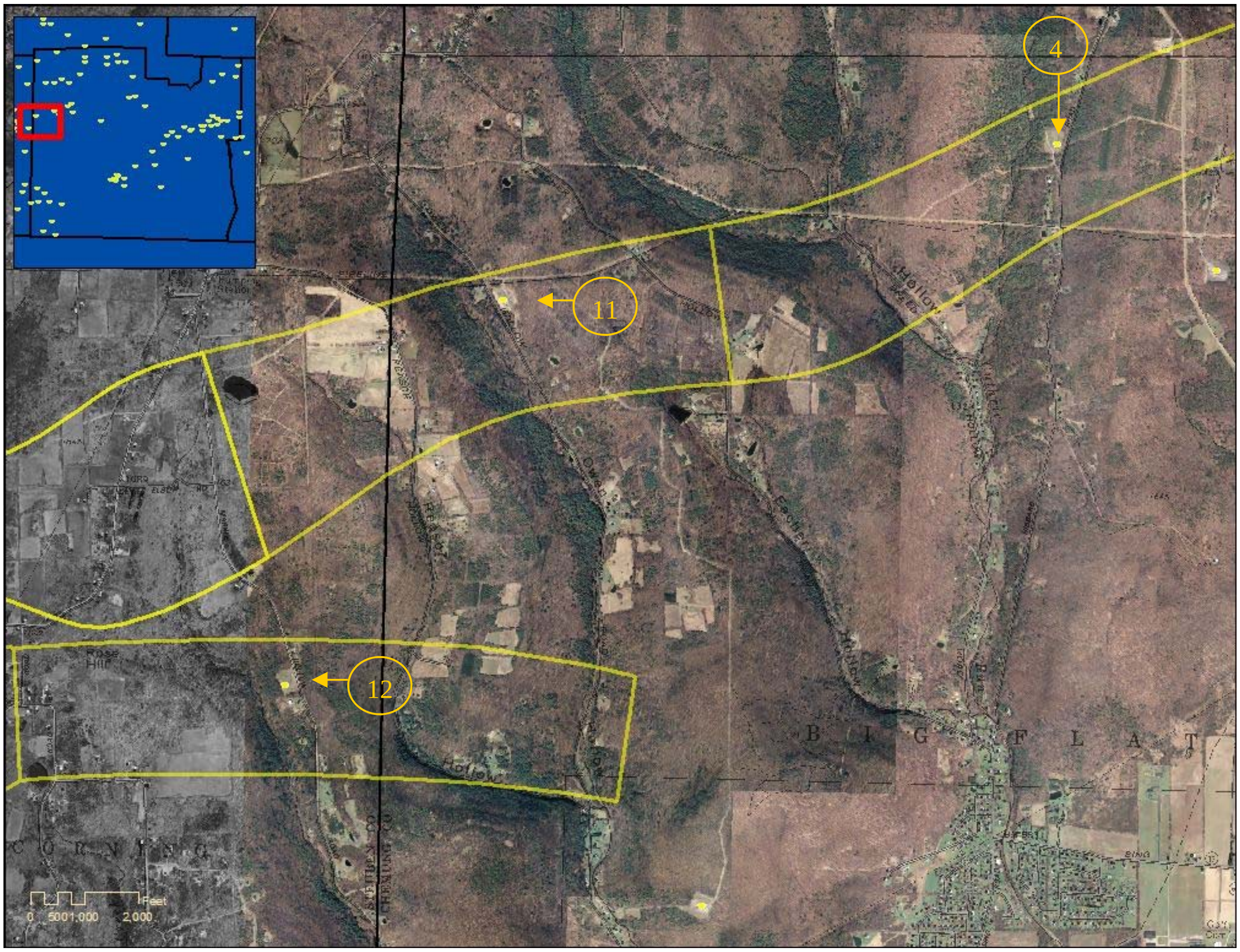
Little 1 11/3/2005

Photos 6.10 Well #10 (Hole number 23827) was drilled as a horizontal Trenton-Black River well and completed in 2006. The well was drilled to a total vertical depth of 9,062 and a total drilled depth of 13,360 feet. The production unit is approximately 650 acres.

Hulett #1 10/5/2006

Hulett #1 5/6/2009

Photo 6.11 This photo shows another portion of the Quackenbush Hill Field in western Chemung County and eastern Steuben County. As with other portions of Quackenbush Hill Field, production unit sizes are approximately 640 acres each.



Photos 6.12 Well #11 (Hole number 22831) was completed in 2000 as a directional well to a total vertical depth of 9,824 feet. The drill site disturbed area was approximately 3.6 acres which has been reclaimed to a fenced area of 0.5 acres.

Lovell 11/13/2001

Lovell 5/6/2009

Photos 6.13 Well #12 (Hole number 22871) was completed in 2002 as a horizontal well to a total vertical depth of 9,955 feet and a total drilled depth of 12,325 feet. The drill site disturbed area was approximately 3.2 acres which has been reclaimed to a fenced area of 0.45 acres.

Henkel 10/22/2002

Henkel 5/6/2009