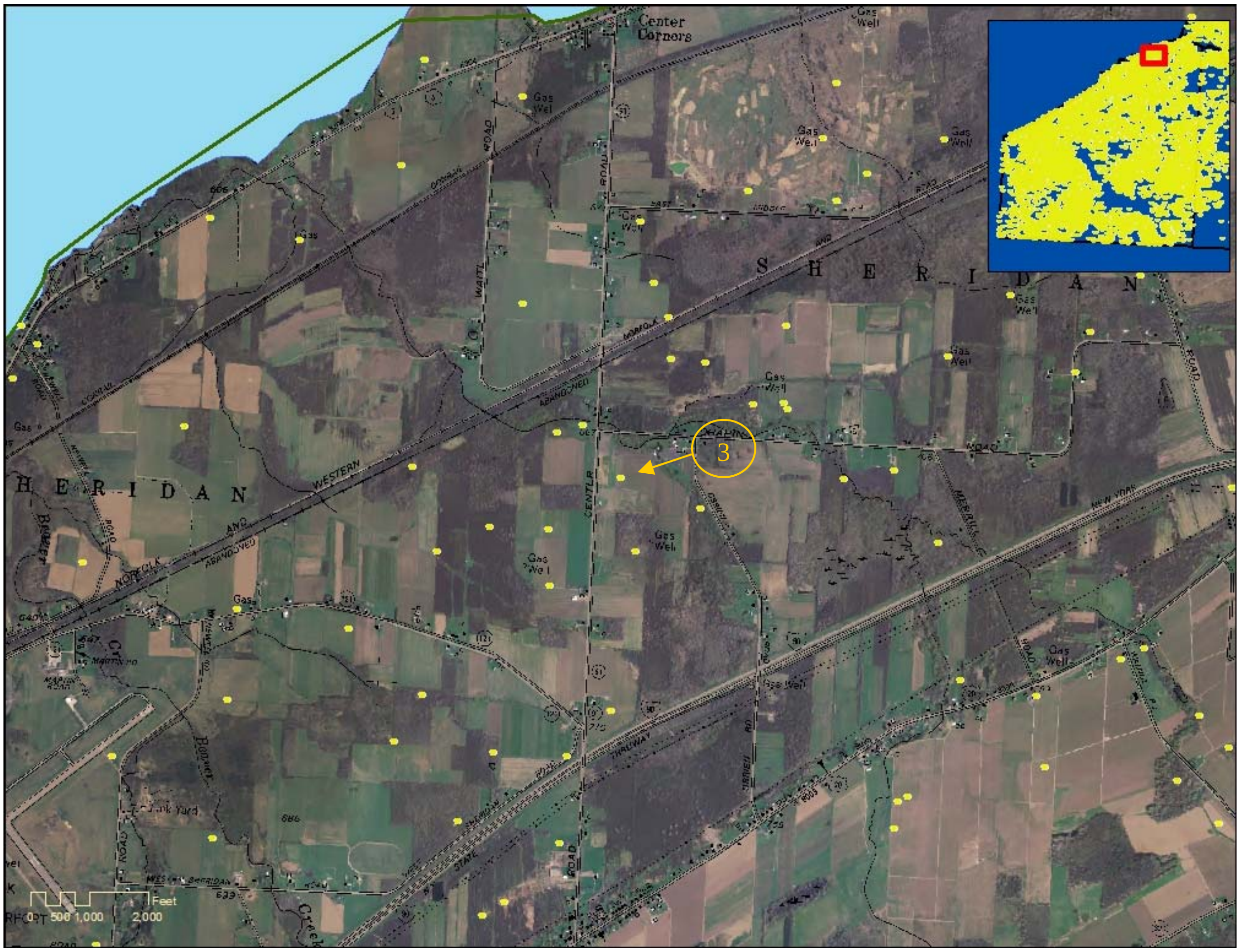


Photo 5.11 a & b The map above shows 77 wells. Well #3 (API Hole number 16427) identified in the map above, and shown in the photo below, was completed in the Town of Sheridan, Chautauqua County in 1981 and was drilled to a depth of 2,012 feet. The map indicates that the nearest producing well to Well #3 is 1/4 mile away.

Horizontal Wells in Single-Well Spacing Units

Statewide spacing for horizontal wells where only one well will be drilled at the surface site provides for one well per 40 acres plus the necessary and sufficient acreage so that there will be 330 feet between the wellbore in the target formation and the spacing unit boundary. This means that the width of the spacing unit will be at least 660 feet and the distance within the target formation between wellbores will also always be at least 660 feet. Surface locations may be somewhat closer together because of the need to begin building angle in the wellbore about 500 feet above the target formation. However, unless the horizontal length of the wellbores within the target formation is limited to 1,980 feet, the spacing units will exceed 40 acres in size. Although it is possible to drill horizontal wellbores of this length, all information provided to date indicates that, in actual practice, lateral distance drilled will normally exceed 2,000 feet and as an example would most likely be 4,000 feet or more, requiring substantially more than 40 acres. Therefore, the overall density of surface locations would be less than 16 wells per square mile. For example, with 4,000 feet as the length of a horizontal wellbore in the target shale formation, a spacing unit would be 4,660 feet long by 660 feet wide, or about 71 acres in size. Nine, instead of 16, spacing units would fit within a square mile, necessitating nine instead of 16 access roads and nine instead of 16 gas gathering lines. Longer laterals would further reduce the number of well pads per square mile. The Department anticipates that the vast majority of horizontal wells will be drilled from common pads (i.e., multi-well pads), reducing surface disturbance even more.

Horizontal Wells with Multiple Wells Drilled from Common Pads

The third statewide spacing option for shale wells provides, initially, for spacing units of up to 640 acres with all the horizontal wells in the unit drilled from a common well pad. Industry estimates that 90% of the wells drilled to develop shale resources by high-volume hydraulic fracturing will be horizontal;[19] as stated above, the Department anticipates that the vast majority of them will be drilled from multi-well pads. This method provides the most flexibility to avoid environmentally sensitive locations within the acreage to be developed and significantly reduces the number of needed well pads and associated roads.

---

[19] ALL Consulting, 2010, p. 7.

With respect to overall land disturbance, the larger surface area of an individual multi-well pad will be more than offset by the fewer total number of well pads within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells.[20] For example, a spacing of 40 acres per well for vertical shale gas wells would result in, on average, of 70 – 80 acres of disturbance for the well pads, access roads and utility corridors (4.8 acres per well[21]) to develop an area of 640 acres. By contrast, a single well pad with 6 to 8 horizontal shale gas wells could access all 640 acres with an average of 7.4 acres of total land disturbance. Table 5.1 below provides another comparison between the well pad acreage disturbed within a 10-square mile area completely developed by multi-well pad horizontal drilling versus single-well pad vertical drilling.[22]

Table 5.1 - Ten square mile area (i.e., 6,400 acres), completely drilled with horizontal wells in multi-well units or vertical wells in single-well units (Updated July 2011)

Spacing Option	Multi-Well 640 Acre	Single-Well 40 Acre
Number of Pads	10	160
Total Disturbance - Drilling Phase	74 Acres (7.4 acres per pad)	768 Acres (4.8 ac. per pad)
% Disturbance - Drilling Phase	1.2%	12%
Total Disturbance - Production Phase	15 Acres (1.5 ac. per pad)	80 Acres (0.5 ac. per pad)
% Disturbance - Production Phase	0.23%	1.25%

It is possible that a single well-pad could be positioned to site wells to reach adjacent units, thereby developing 1,280 acres or more without increasing the land disturbance described above for multi-well pads. Use of longer lateral wellbores is another potential method for developing larger areas with less land disturbance.[23]

---

[20] Alpha, 2009, p. 6-2.

[21] ALL Consulting, 2010, p. 14.

[22] NTC, 2009, p. 29, updated with information from ALL Consulting, 2010.

[23] ALL Consulting, 2010, p. 87.

Variances or Non-Conforming Spacing Units

The ECL has always provided for variances from statewide spacing or non-conforming spacing units, with justification, which could result in a greater well density for any of the above options. A variance from statewide spacing or a non-conforming spacing unit requires the Department to issue a well-specific spacing order following public comment and, if necessary, an adjudicatory hearing. Environmental impacts associated with any well to be drilled under a particular spacing order will continue to be reviewed separately from the spacing variance upon receipt of a specific well permit application.

5.2 Horizontal Drilling

The first horizontal well in New York was drilled in 1989, and in 2008 approximately 10% of the well permit applications received by the Department were for directional or horizontal wells. The predominant use of horizontal drilling associated with natural gas development in New York has been for production from the Black River and Herkimer Formations during the past several years. The combination of horizontal drilling and hydraulic fracturing is widely used in other areas of the United States as a means of recovering gas from tight shale formations.

Except for the use of specialized downhole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling, with the same protocols in place for aquifer protection, fluid containment and waste handling. As described below, there are four primary differences between horizontal drilling for shale gas development and the drilling described in the 1992 GEIS. One is that larger rigs may be used for all or part of the drilling, with longer per-well drilling times than were described in the 1992 GEIS. The second is that multiple wells are likely to be drilled from each well site (or well pad). The third is that drilling mud rather than air may be used while drilling the horizontal portion of the wellbore to lubricate and cool the drill bit and to clean the wellbore. Fourth and finally, the volume of rock cuttings returned to the surface from the target formation will be greater for a horizontal well than for a vertical well.

Vertical drilling depth will vary based on target formation and location within the state. Chapter 5 of the 1992 GEIS discusses New York State's geology with respect to oil and gas production. Chapter 4 of this SGEIS expands upon that discussion, with emphasis on the Marcellus and Utica Shales. Chapter 4 includes maps which show depths and thicknesses related to these two shales.

In general, wells will be drilled vertically to a depth of about 500 feet above the top of a target interval, such as the Union Springs Member of the Marcellus Shale. Drilling may continue with the same rig, or a larger drill rig may be brought onto the location to build angle and drill the horizontal portion of the wellbore. A downhole motor behind the drill bit at the end of the drill pipe is used to accomplish the angled or directional drilling deep within the earth. The drill pipe is also equipped with inclination and azimuth sensors located about 60 feet behind the drill bit to continuously record and report the drill bit's location.

Current drilling technology for onshore consolidated strata results in maximum lateral lengths that do not greatly exceed the depth of the well. For example, a 5,000-foot deep well would generally not have a lateral length of significantly greater than 5,000 feet.[24] This may change, however, as drilling technology continues to evolve. The length of the horizontal wellbore can also be affected by the operator's lease position or compulsory integration status within the spacing unit, the configuration of the approved spacing unit and wellbore paths, and other factors which influence well design.

5.2.1 Drilling Rigs

Wells for shale gas development using high-volume hydraulic fracturing will be drilled with rotary rigs. Rotary rigs are described in the 1992 GEIS, with the typical rotary rigs used in New York at the time characterized as either 40 to 45-foot high "singles" or 70 to 80-foot high "doubles." These rigs can, respectively, hold upright one joint of drill pipe or two connected joints. "Triples," which hold three connected joints of drill pipe upright and are over 100 feet high, were not commonly used in New York State when the 1992 GEIS was prepared. However, triples have been more common in New York since 1992 for natural gas storage field drilling and to drill some Trenton-Black River wells, and may be used for drilling wells in the Marcellus Shale and other low-permeability reservoirs.

Operators may use one large rig to drill an entire wellbore from the surface to toe of the horizontal bore, or may use two or three different rigs in sequence. For each well, only one rig is over the hole at a time. At a multi-well site, two rigs may be present on the pad at once, but more than two are unlikely because of logistical and space considerations as described below.

---

[24] ALL Consulting, 2010, pp. 87-88.

When two rigs are used (in sequence) to drill a well, a smaller rig of similar dimensions to the typical rotary rigs described in the 1992 GEIS would first drill the vertical portion of the well. Only the rig used to drill the horizontal portion of the well is likely to be significantly larger than what is described in the 1992 GEIS. This rig may be a triple, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Auxiliary equipment includes various tanks (for water, fuel and drilling mud), generators, compressors, solids control equipment (shale shaker, de-silter, de-sander), choke manifold, accumulator, pipe racks and the crew's office space (dog house). Initial work with the smaller rig would typically take up to two weeks, followed by another up to two weeks of work with the larger rig. These estimates include time for casing and cementing the well, and may be extended if drilling is slower than anticipated because of properties of the rock, or if other problems or unexpected delays occur.

When three rigs are used to drill a well, the first rig is used to drill, case, and cement the surface hole. This event generally takes about 8 to12 hours. The dimensions of this rig would be consistent with what is described in the 1992 GEIS. The second rig for drilling the remainder of the vertical hole would also be consistent with 1992 GEIS descriptions and would again typically be working for up to 14 days, or longer if drilling is slow or problems occur. The third rig, equipped to drill horizontally, would, as noted above, be the only one that might exceed 1992 GEIS dimensions, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Work with this rig would take up to 14 days, or longer if drilling is slow or other problems or delays occur.

An important component of the drilling rig is the blow-out prevention (BOP) system. This system is discussed in the 1992 GEIS. In summary, BOP system on a rotary drilling rig is a pressure control system designed specifically to contain and control a "kick" (i.e., unexpected pressure resulting in the flow of formation fluids into the wellbore during drilling operations). Other than the well itself, the BOP system basically consists of four parts: 1) the blow-out preventer stack, 2) the accumulator unit, 3) the choke manifold, and 4) the kill line. Blow-out preventers are manually or hydraulically operated devices installed at the top of the surface casing. Within the blow-out preventer there may be a combination of different types of devices to seal off the well. Pipe rams contain two metal blocks with semi-circular notches that fit together around the outside of the drill pipe when it is in the hole to block movement of fluids around the pipe. Blind rams contain two rubber faced metal blocks that can completely seal off the hole when there is no drill pipe in it. Annular or "bag" type blowout preventers contain a resilient packing element which expands inward to seal off the hole with or without drill pipe. In accordance with 6 NYCRR §554.4, the BOP system must be maintained and in proper working order during operations. A BOP test program is employed to ensure the BOP system is functioning properly if and when needed.

Appendix 7 includes sample rig specifications provided by Chesapeake Energy. As noted on the specs, fuel storage tanks associated with the larger rigs would hold volumes of 10,000 to 12,000 gallons.

In summary, the rig work for a single horizontal well – including drilling, casing and cementing – would generally last about four to five weeks, subject to extension for slow drilling or other unexpected problems or delays. A 150-foot tall, large-footprint rotary rig may be used for the entire duration or only for the actual horizontal drilling. In the latter case, smaller, 1992 GEIS-consistent rigs would be used to drill the vertical portion of the wellbore. The rig and its associated auxiliary equipment would typically move off the well before fracturing operations commence.

Photos 5.12 – 5.15 are photographs of drilling rigs.

Photo 5.12 Double. Union Drilling Rig 54, Olsen 1B, Town of Fenton, Broome County NY. Credit: NYS DEC 2005.

Photo 5.13 Double. Union Drilling Rig 48. Trenton-Black River well, Salo 1, Town of Barton, Tioga County NY. Source: NYS DEC 2008.

Photo 5.14 Triple. Precision Drilling Rig 26. Ruger 1 well, Horseheads, Chemung County. Credit: NYS DEC 2009.

Photo 5.15 Top Drive Single. Barber and DeLine rig, Sheckells 1, Town of Cherry Valley, Otsego County. Credit: NYS DEC 2007.

5.2.2 Multi-Well Pad Development

Horizontal drilling from multi-well pads is the common development method employed to develop Marcellus Shale reserves in the northern tier of Pennsylvania and is expected to be common in New York as well. In New York, ECL 23 requires that all horizontal wells in a multi-well shale unit be drilled within three years of the date the first well in the unit commences drilling, to prevent operators from holding acreage within large spacing units without fully developing the acreage.[25]

As described above, the space required for hydraulic fracturing operations for a multi-well pad is dictated by a number of factors but is expected to most commonly be about 3.5 acres.[26] The well pad is often centered in the spacing unit.

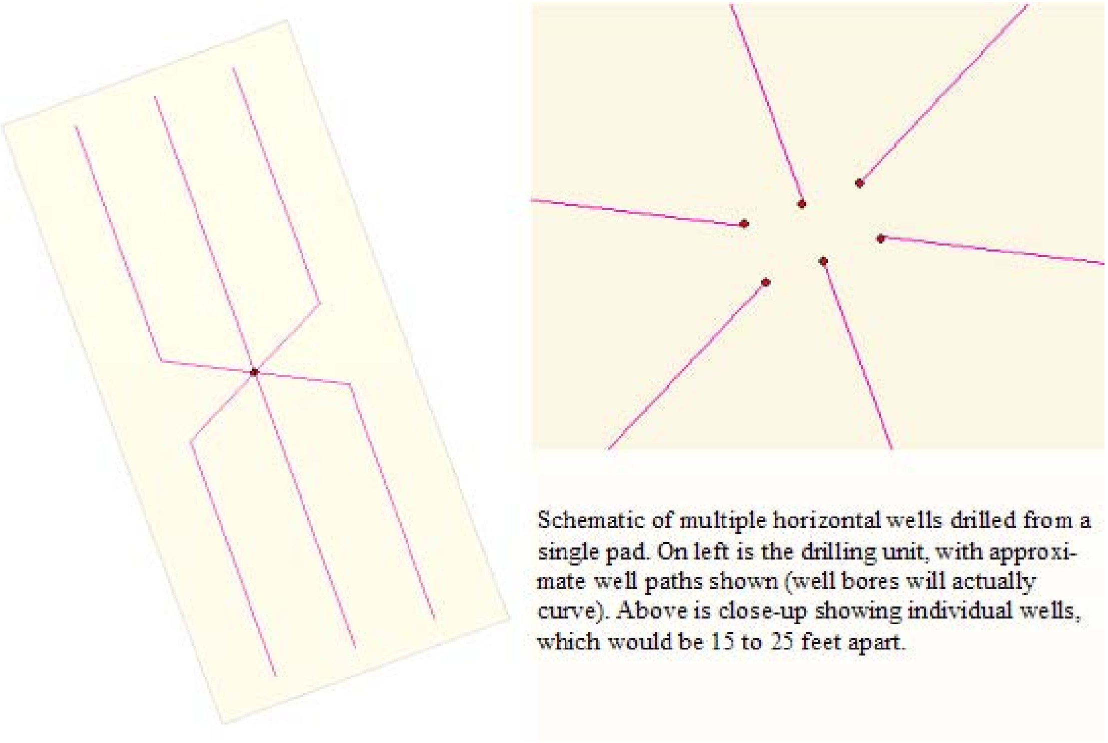
Several factors determine the optimal drilling pattern within the target formation. These include geologic controls such as formation depth and thickness, mechanical and physical factors associated with the well construction program, production experience in the area, lease position and topography or surface restrictions that affect the size or placement of pads.[27] Often, evenly spaced parallel horizontal bores are drilled in opposite directions from surface locations arranged in two parallel rows. When fully developed, the resultant horizontal well pattern underground could resemble two back-to-back pitchforks [Figure 5.2]. Other, more complex patterns may also be proposed.

---

[25] ECL §23-0501.

[26] Cornue, 2011.

[27] ALL Consulting, 2010, p. 88.



Schematic of multiple horizontal wells drilled from a single pad. On left is the drilling unit, with approximate well paths shown (well bores will actually curve). Above is close-up showing individual wells, which would be 15 to 25 feet apart.

Figure 5.2 - Possible well spacing unit configurations and wellbore paths

Because of the close well spacing at the surface, most operators have indicated that only one drilling rig at a time would be operating on any given well pad. One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently. Efficiency and the economics of mobilizing equipment and crews would dictate that all wells on a pad be drilled sequentially, during a single mobilization. However, this may be affected by the timing of compulsory integration proceedings if wellbores are proposed to intersect unleased acreage.[28] Other considerations may result in gaps between well drilling episodes at a well pad. For instance, early development in a given area may consist of initially drilling and stimulating one to three wells on a pad to test productivity, followed by additional wells later, but within the required 3-year time frame. As development in a given area matures and the results become more predictable, the frequency of drilling and completing all the wells on each pad with continuous activity in a single mobilization would be expected to increase.

---

[28] ECL §23-0501 2.b. prohibits the wellbore from crossing unleased acreage prior to issuance of a compulsory integration order.

5.2.3 Drilling Mud

The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid. Operators who provided responses to the Department's information requests stated that the horizontal portion, drilled after any fresh water aquifers have been sealed behind cemented surface casing, and typically cemented intermediate casing, may be drilled with a mud that may be (i) water-based, (ii) potassium chloride/polymer-based with a mineral oil lubricant, or (iii) synthetic oil-based. Synthetic oil-based muds are described as "food-grade" or "environmentally friendly." When drilling horizontally, mud is needed for (1) powering and cooling the downhole motor and bit used for directional drilling, (2) using navigational tools which require mud to transmit sensor readings, (3) providing stability to the horizontal borehole while drilling and (4) efficiently removing cuttings from the horizontal hole. Other operators may drill the horizontal bore "on air," (i.e., with compressed air) using special equipment to control fluids and gases that enter the wellbore. Historically, most wells in New York are drilled on air and air drilling is addressed by the 1992 GEIS.

Drilling mud is contained and managed on-site through the rig's mud system which is comprised of a series of piping, separation equipment, and tanks. Photo 5.16 depicts some typical mud-system components. During drilling or circulating mud is pumped from the mud holding tanks at the surface down hole through the drill string and out the drill bit, and returns to the surface through the annular space between the drill string and the walls of the bore hole, where it enters the flowline and is directed to the separation equipment. Typical separation equipment includes shale shakers, desanders, desilters and centrifuges which separate the mud from the rock cuttings. The mud is then re-circulated back into the mud tanks where it is withdrawn by the mud pump for continued use in the well. As described in the 1992 GEIS, used drilling mud is typically reconditioned for use at a subsequent well. The subsequent well may be located on the same well pad or at another location.

Photo 5.16 - Drilling rig mud system (blue tanks)

5.2.4 Cuttings

The rock chips and very fine-grained rock fragments removed by the drilling process and returned to the surface in the drilling fluid are known as "cuttings" and are contained and managed either in a lined on-site reserve pit or in a closed-loop tank system.[29] As described in Section 5.13.1, the proper disposal method for cuttings is determined by the composition of the fluid or fluids used during drilling. The proper disposal method will also dictate how the cuttings must be contained on-site prior to disposal, as described by Section 7.1.9.

5.2.4.1 Cuttings Volume

Horizontal drilling penetrates a greater linear distance of rock and therefore produces a larger volume of drill cuttings than does a well drilled vertically to the same depth below the ground

---

[29] Adapted from Alpha, 2009, p. 133.

surface. For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.

5.2.4.2 NORM in Marcellus Cuttings

To determine NORM concentrations and the potential for exposure to NORM contamination in Marcellus rock cuttings and cores (i.e., continuous rock samples, typically cylindrical, recovered during specialized drilling operations), the Department conducted field and sample surveys using portable Geiger counter and gamma ray spectroscopy methods. Gamma ray spectroscopy analyses were performed on composited Marcellus samples collected from two vertical wells drilled through the Marcellus, one in Lebanon (Madison County), and one in Bath (Steuben County). The results of these analyses are presented in Table 5.2a. Department staff also used a Geiger counter to screen three types of Marcellus samples: cores from the New York State Museum's collection in Albany; regional outcrops of the unit; and various Marcellus well sites from the west-central part of the state, where most of the vertical Marcellus wells in NYS are currently located. These screening data are presented in Table 5.2b. Additional radiological analytical data for Marcellus Shale drill cuttings has been reported from Marcellus wells in Pennsylvania. Samples were collected from loads of drill cuttings being transported for disposal, as well as directly from the drilling rigs during drilling of the horizontal legs of the wells. The materials sampled were screened in-situ with a micro R meter, and analyzed by gamma ray spectroscopy. These data are provided in Table 5.3. As discussed further in Chapter 6, the results, which indicate levels of radioactivity that are essentially equal to background values, do not indicate an exposure concern for workers or the general public associated with Marcellus cuttings.

Table 5.2 - 2009 Marcellus Radiological Data

Table 5.2a Marcellus Radiological Data from Gamma Ray Spectroscopy Analyses

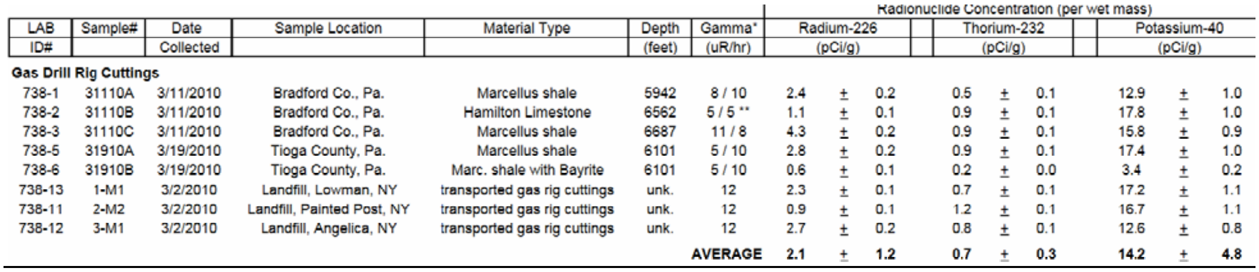
Well (Depth)	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Crouch C 4H (1040 feet - 1115 feet)	31-053-26305-00-00	3/17/09	Lebanon (Madison)	K-40	14.438 +/- 1.727 pCi/g
				Tl-208	0.197 +/- 0.069 pCi/g
				Pb-210	2.358 +/- 1.062 pCi/g
				Bi-212	0.853 +/- 0.114 pCi/g
				Bi-214	1.743 +/- 0.208 pCi/g
				Pb-214	1.879 +/- 0.170 pCi/g
				Ra-226	1.843 +/- 0.573 pCi/g
				Ac-228	0.850 +/- 0.169 pCi/g
				Th-234	1.021 +/- 0.412 pCi/g
				U-235	0.185 +/- 0.083 pCi/g
Blair 2A (2550’ - 2610’)	31-101-02698-01-00	3/26/09	Bath (Steuben)	K-40	22.845 +/- 2.248 pCi/g
				Tl-208	0.381 +/- 0.065 pCi/g
				Pb-210	0.535 +/- 0.712 pCi/g
				Bi-212	1.174 +/- 0.130 pCi/g
				Bi-214	0.779 +/- 0.120 pCi/g
				Pb-214	0.868 +/- 0.114 pCi/g
				Ra-226	0.872 +/- 0.330 pCi/g
				Ac-228	1.087 +/- 0.161 pCi/g
				Th-234	0.567 +/- 0.316 pCi/g
				U-235	0.079 +/- 0.058 pCi/g

Table 5.2b Marcellus Radiological Data from Geiger Counter Screening

Media Screened	Well	Date	Location (County)	Results
Cores	Beaver Meadow 1	3/12/09	NYS Museum (Albany)	0.005 - 0.080 mR/hr
	Oxford 1	3/12/09	NYS Museum (Albany)	0.005 - 0.065 mR/hr
	75 NY-14	3/12/09	NYS Museum (Albany)	0.015 - 0.065 mR/hr
	EGSP #4	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Jim Tiede	3/12/09	NYS Museum (Albany)	0.005 - 0.025 mR/hr
	75 NY-18	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	75 NY-12	3/12/09	NYS Museum (Albany)	0.015 - 0.045 mR/hr
	75 NY-21	3/12/09	NYS Museum (Albany)	0.005 - 0.040 mR/hr
	75 NY-15	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Matejka	3/12/09	NYS Museum (Albany)	0.005 - 0.090 mR/hr
Outcrops	N/A	3/24/2009	Onesquethaw Creek (Albany)	0.02 - 0.04 mR/hr
	N/A	3/24/2009	DOT Garage, CR 2 (Albany)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	SR 20, near SR 166 (Otsego)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	Richfield Springs (Otsego)	0.01 - 0.06 mR/hr
	N/A	3/24/2009	SR 20 (Otsego)	0.01 - 0.03 mR/hr
	N/A	3/24/2009	Gulf Rd (Herkimer)	0.01 - 0.04 mR/hr
Well Sites	Beagell 2B	4/7/2009	Kirkwood (Broome)	0.04 mR/hr *
	Hulsebosch 1	4/2/2009	Elmira City (Chemung)	0.03 mR/hr *
	Bush S1	4/2/2009	Elmira (Chemung)	0.03 mR/hr *

	Parker 1	4/7/2009	Oxford (Chenango)	0.05 mR/hr *
Well Sites	Donovan Farms 2	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Fee 1	3/30/2009	Sparta (Livingston)	0.02 mR/hr *
	Meter 1	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Schiavone 2	4/6/2009	Reading (Schuyler)	0.05 mR/hr *
	WGI 10	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	WGI 11	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	Calabro T1	3/26/2009	Orange (Schuyler)	0.03 mR/hr *
	Calabro T2	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Frost 2A	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Webster T1	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Haines 1	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	Haines 2	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	McDaniels 1A	4/1/2009	Urbana (Steuben)	0.03 mR/hr *
	Drumm G2	4/1/2009	Bradford (Steuben)	0.07 mR/hr *
	Hemley G2	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Lancaster M1	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Maxwell 1C	4/2/2009	Caton (Steuben)	0.07 mR/hr *
	Scudder 1	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Blair 2A	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Retherford 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Carpenter 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Cook 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Zinck 1	4/1/2009	Woodhull (Steuben)	0.07 mR/hr *
	Tiffany 1	4/7/2009	Owego (Tioga)	0.03 mR/hr *
*maximum values detected				

Table 5.3 - Gamma Ray Spectroscopy



							Radionuclide Concentration (per wet mass)								
LAB	Sample#	Date	Sample Location	Material Type	Depth	Gamma*	Radium-226			Thorium-232			Potassium-40		
ID#		Collected			(feet)	(uR/hr)	(pCi/g)			(pCi/g)			(pCi/g)		
Gas Drill Rig Cuttings															
738-1	31110A	3/11/2010	Bradford Co., Pa.	Marcellus shale	5942	8 / 10	2.4	±	0.2	0.5	±	0.1	12.9	±	1.0
738-2	31110B	3/11/2010	Bradford Co., Pa.	Hamilton Limestone	6562	5 / 5 **	1.1	±	0.1	0.9	±	0.1	17.8	±	1.0
738-3	31110C	3/11/2010	Bradford Co., Pa.	Marcellus shale	6687	11 / 8	4.3	±	0.2	0.9	±	0.1	15.8	±	0.9
738-5	31910A	3/19/2010	Tioga County, Pa.	Marcellus shale	6101	5 / 10	2.8	±	0.2	0.9	±	0.1	17.4	±	1.0
738-6	31910B	3/19/2010	Tioga County, Pa.	Marc. shale with Bayrite	6101	5 / 10	0.6	±	0.1	0.2	±	0.0	3.4	±	0.2
738-13	1-M1	3/2/2010	Landfill, Lowman, NY	transported gas rig cuttings	unk.	12	2.3	±	0.1	0.7	±	0.1	17.2	±	1.1
738-11	2-M2	3/2/2010	Landfill, Painted Post, NY	transported gas rig cuttings	unk.	12	0.9	±	0.1	1.2	±	0.1	16.7	±	1.1
738-12	3-M1	3/2/2010	Landfill, Angelica, NY	transported gas rig cuttings	unk.	12	2.7	±	0.2	0.8	±	0.1	12.6	±	0.8
						AVERAGE	**2.1**	±	**1.2**	**0.7**	±	**0.3**	**14.2**	±	**4.8**

5.2.5 Management of Drilling Fluids and Cuttings

The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases.

5.2.5.1 Reserve Pits on Multi-Well Pads

The 1992 GEIS describes the construction, use and reclamation of lined reserve pits, (also called "drilling pits" or "mud pits") to contain cuttings and fluids associated with the drilling process. Rather than using a separate pit for each well on a multi-well pad, operators may propose to maintain a single pit on the well pad until all wells are drilled and completed. The pit would need to be adequately sized to hold cuttings from all the wells, unless the cuttings are removed intermittently as needed to ensure adequate room for drilling-associated fluids and precipitation. Under existing regulations, fluid associated with each well would have to be removed within 45 days of the cessation of drilling operations, unless the operator has submitted a plan to use the fluids in subsequent operations and the Department has inspected and approved the pit.[30] Chapter 7 discusses restrictions related to the use of reserve pits for managing drilling fluids and cuttings for high-volume hydraulic fracturing.

5.2.5.2 Closed-Loop Tank Systems

The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit. The containers may include tanks or bins that may have closed tops, open tops or open tops in combination with open sides. They may be stationary or truck-, trailer-, or skid-mounted. Regardless of the specific design of the containers, the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.

Depending on the drilling fluid utilized, a variety of types of separation equipment may be employed within a closed-loop tank system to separate the liquids from the cuttings prior to

---

[30] 6 NYCRR §554.1(c)(3).

capture within the system's containers. For air drilling employing a closed-loop tank system, shale shakers or other gravity-based equipment would likely be utilized to separate any formation fluids from the cuttings whereas mud drilling would employ equipment which is virtually identical to that of the drilling mud systems described previously in Section 5.2.3.

In addition to the equipment typically employed in a drilling mud system, operators may elect to utilize additional solids control equipment within the closed-loop system when drilling on mud, in an effort to further separate liquids from the cuttings. Such equipment could include but is not limited to drying shakers, vertical or horizontal rotary cuttings dryers, squeeze presses, or centrifuges[31] and when oil-based drilling muds are utilized the separation process may also include treatment to reduce surface tension between the mud and the cuttings.[32,33] The additional separation results in greater recovery of the drilling mud for re-circulation and produces dryer cuttings for off-site disposal.

Depending on the moisture-content of the cuttings, operators may drain or vacuum free-liquids from the cuttings container, or they may mix absorbent agents such as lime, saw dust or wood chips into the cuttings in order to absorb any free-liquids prior to hauling off-site for disposal. This mixing may take place in the primary capture container where the cuttings are initially collected following separation or in a secondary container located on the well pad.

Operators may simply employ primary capture containers which are suitable for capturing and transporting cuttings from the well site, or they may transfer cuttings from the primary capture container to a secondary capture container for transport purposes. If cuttings will be transferred between containers, front end loaders, vacuum trucks or other equipment would be utilized and all transfers will be required to occur in a designated transfer area on the well pad, which will be required to be lined.

---

[31] ANL, 2011(a).

[32] The American Oil & Gas Reporter, August 2010, p. 92-93.

[33] Dugan, April 2008.

Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:

- Eliminates the time and expense associated with reserve pit construction and reclamation;
- Reduces the surface disturbance associated with the well pad;
- Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;
- Lowers mud replacement costs by capturing and re-circulating drilling mud;
- Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and
- Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.

5.3 Hydraulic Fracturing

The 1992 GEIS discusses, in Chapter 9, hydraulic fracturing operations using water-based gel and foam, and describes the use of water, hydrochloric acid and additives including surfactants, bactericides,[34] clay and iron inhibitors and nitrogen. The fracturing fluid is an engineered product; service providers vary the design of the fluid based on the characteristics of the reservoir formation and the well operator's objectives. In the late 1990s, operators and service companies in other states developed a technology known as "slickwater fracturing" to develop shale formations, primarily by increasing the amount and proportion of water used, reducing the use of gelling agents and adding friction reducers. Any fracturing fluid may also contain scale and corrosion inhibitors.

ICF International, which reviewed the current state of practice of hydraulic fracturing under contract with NYSERDA, states that the development of water fracturing technologies has reduced the quantity of chemicals required to hydraulically fracture target reservoirs and that

---

[34] Bactericides must be registered for use in New York in accordance with ECL §33-0701. Well operators, service companies, and chemical supply companies were reminded of this requirement in an October 28, 2008 letter from the Division of Mineral Resources formulated in consultation with the former Division of Solid and Hazardous Materials, now Materials Management. This correspondence also reminded industry of the corresponding requirement that all bactericides be properly labeled and that the labels for such products be kept on-site during application and storage.

slickwater treatments have yielded better results than gel treatments in the Barnett Shale.[35] Poor proppant suspension and transport characteristics of water versus gel are overcome by the low permeability of shale formations which allow the use of finer-grained proppants and lower proppant concentrations.[36] The use of friction reducers in slickwater fracturing procedures reduce the required pumping pressure at the surface, thereby reducing the number and power of pumping trucks needed.[37] In addition, according to ICF, slickwater fracturing causes less formation damage than other techniques such as gel fracturing.[38]

Both slickwater fracturing and foam fracturing have been proposed for Marcellus Shale development. As foam fracturing is already addressed by the 1992 GEIS, this document focuses on slickwater fracturing. This type of hydraulic fracturing is referred to herein as "high-volume hydraulic fracturing" because of the large water volumes required.

5.4 Fracturing Fluid

The fluid used for slickwater fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid.[39] The Department has collected compositional information on many of the additives proposed for use in fracturing shale formations in New York directly from chemical suppliers and service companies. This information has been evaluated by the Department's Division of Air Resources (DAR) and DOW as well as the NYSDOH's Bureaus of Water Supply Protection and Toxic Substances Assessment. It has also been reviewed by technical consultants contracted by NYSERDA[40] to conduct research related to the preparation of this document. Discussion of potential environmental impacts and mitigation measures in Chapters 6 and 7 of this SGEIS reflect analysis and input by all of the foregoing entities.

---

[35] ICF Task 1, 2009. pp. 10, 19.

[36] ICF Task 1, 2009. pp. 10, 19.

[37] ICF Task 1, 2009. P. 12.

[38] ICF Task 1, 2009. P. 19.

[39] GWPC, April 2009, pp. 61-62.

[40] Alpha Environmental Consultants, Inc., ICF International, URS Corporation.

Six service companies[41] and 15 chemical suppliers[42] have provided additive product compositional information to the Department in the form of product Material Safety Data Sheets (MSDSs)[43] and product composition disclosures consisting of chemical constituent names and their associated Chemical Abstract Service (CAS) Numbers,[44] as well as chemical constituent percent by weight information. Altogether, some compositional information is on file with the Department for 235 products, with complete[45] product composition disclosures and MSDSs on file for 167 of those products. Within these products are 322 unique chemicals whose CAS Numbers have been disclosed to the Department and at least 21 additional compounds whose CAS Numbers have not been disclosed due to the fact that many are mixtures. Table 5.4 is an alphabetical list of all products for which complete chemical information, including complete product composition disclosures and MSDSs, has been provided to the Department. Table 5.5 is an alphabetical list of products for which only partial chemical composition information has been provided to the Department, either in the form of product MSDSs or product composition disclosures which appear to be lacking information. Any product whose name does not appear within Table 5.4 or Table 5.5 was not evaluated in this SGEIS either because no chemical information was submitted to the Department or because the product has not been proposed for use in high-volume hydraulic fracturing operations in New York to date. These tables are included for informational purposes only and are not intended to restrict the proposal of additional additive products. See Chapter 8, Section 8.2.1.2 for a description of the permitting requirements related to fracturing additive information.

---

[41] BJ Services, Frac Tech Services, Halliburton, Superior Well Services, Universal Well Services, Schlumberger.

[42] Baker Petrolite, CESI/Floteck, Champion Technologies/Special Products, Chem EOR, Cortec, Fleurin Fragrances, Industrial Compounding, Kemira, Nalco, PfP Technologies, SNF Inc., Stepan Company, TBC-Brinadd/Texas United Chemical, Weatherford/Clearwater, and WSP Chemicals & Technology.

[43] MSDSs are regulated by the Occupational Safety and Health Administration (OSHA)'s Hazard Communication Standard, 29 CFR 1910.1200(g) and are described in Chapter 8.

[44] Chemical Abstracts Service (CAS) is a division of the American Chemical Society. CAS assigns unique numerical identifiers to every chemical described in the literature. The intention is to make database searches more convenient, as chemicals often have many names.

[45] The Department defines a complete product composition disclosure to include the chemical names and associated CAS Numbers of every constituent within a product, as well as the percent by weight information associated with each constituent of a product.

Table 5.4 - Fracturing Additive Products – Complete Composition
Disclosure Made to the Department (Updated July 2011)

Product Name
ABF
Acetic Acid 0.1-10%
Acid Pensurf / Pensurf
Activator W
AGA 150 / Super Acid Gell 150
AI-2
Aldacide G
Alpha 125
Ammonium Persulfate/OB Breaker
APB-1, Ammonium Persulfate Breaker
AQF-2
ASP-820
B315 / Friction Reducer B315
B317 / Scale Inhibitor B317
B859 / EZEFLO Surfactant B859 / EZEFLO F103 Surfactant
B867 / Breaker B867 / Breaker J218
B868 / EB-CLEAN B868 LT Encapsulated Breaker / EB-Clean J479 LT Encapsulated Breaker
B875 / Borate Crosslinker B875 / Borate Crosslinker J532
B880 / EB-CLEAN B880 Breaker / EB-CLEAN J475 Breaker
B890 / EZEFLO Surfactant B890 / EZEFLO F100 Surfactant
B900 / EZEFLO Surfactant B900/ EZEFLO F108 Surfactant
B910 / Corrosion Inhibitor B910 / Corrosion Inhibitor A264
B916 / Gelling Agent ClearFRAC XT B916 / Gelling Agent ClearFRAC XT J590
BA-2
BA-20
BA-40L
BA-40LM
BC-140
BC-140 X2
BE-3S
BE-6
BE-7

Product Name
BE-9
BF-1
BF-7 / BF-7L
BioClear 1000 / Unicide 1000
Bio-Clear 200 / Unicide 2000
Breaker FR
BXL-2, Crosslinker/ Buffer
BXL-STD / XL-300MB
Carbon Dioxide
CC-302T
CI-14
CL-31
CLA-CHEK LP
Claproteck CF
CLA-STA XP
Clay Treat PP
Clay Treat TS
Clay Treat-3C
Clayfix II
Clayfix II plus
CPF-X Plus
Cronox 245 ES
CS-250 SI
CS-650 OS, Oxygen Scavenger
CS-Polybreak 210
CS-Polybreak 210 Winterized
CT-ARMOR
EB-4L
Enzyme G-NE
FAC-1W / Petrostep FAC-1W
FAC-3W / Petrostop FAC-3W
FE-1A
FE-2
FE-2A
FE-5A
Ferchek
Ferchek A
Ferrotrol 300L
Flomax 50
Flomax 70 / VX9173

Product Name
FLOPAM DR-6000 / DR-6000
FLOPAM DR-7000 / DR-7000
Formic Acid
FR-46
FR-48W
FR-56
FRP-121
FRW-14
GasPerm 1000
GBL-8X / LEB-10X / GB-L / En-breaker
GBW-30 Breaker
Green-Cide 25G / B244 / B244A
H015 / Hydrochloric Acid 15% H15
HAI-OS Acid Inhibitor
HC-2
High Perm SW-LB
HPH Breaker
HPH foamer
Hydrochloric Acid
Hydrochloric Acid (HCl)
Hydrochloric Acid 10.1-15%
HYG-3
IC 100L
ICA-720 / IC-250
ICA-8 / IC-200
ICI-3240
Inflo-250
InFlo-250W / InFlo-250 Winterized
Iron Check / Iron Chek
Iron Sta IIC / Iron Sta II
Isopropyl Alcohol
J313 / Water Friction-Reducing Agent J313
J534 / Urea Ammonium Nitrate Solution J534
J580 / Water Gelling-Agent J580
K-34
K-35
KCI
L058 / Iron Stabilizer L58
L064 / Temporary Clay Stabilizer L64
LGC-35 CBM

Product Name
LGC-36 UC
LGC-VI UC
Losurf 300M
M003 / Soda Ash M3
MA-844W
Methanol
MO-67
Morflo III
MSA-II
Muriatic Acid 36%
Musol A
N002 / Nitrogen N_2
NCL-100
Nitrogen
Nitrogen, Liquid N_2
OptiKleen-WF
Para Clear D290 / ParaClean II
Paragon 100 E+
Parasperse
Parasperse Cleaner
PSI-720
PSI-7208
Salt
SAS-2
Scalechek LP-55
Scalechek LP-65
Scalechek SCP-2 / SCP-2
Scalehib 100 / Super Scale Inhibitor / Scale Clear SI-112
SGA II
Shale Surf 1000
Shale Surf 1000 Winterized
SI 103
Sodium Citrate
SP Breaker
STIM-50 / LT-32
Super OW 3
Super Pen 2000
SuperGel 15
U042 / Chelating Agent U42
U066 / Mutual Solvent U66

Product Name
Unicide 100 / EC6116A
Unifoam
Unigel 5F
UniHibA / SP-43X
UnihibG / S-11
Unislik ST 50 / Stim Lube
Vicon NF
WG-11
WG-17
WG-18
WG-35
WG-36
WLC-6
XL-1
XL-8
XLW-32
Xylene

Table 5.5 - Fracturing Additive Products – Partial Composition Disclosure to the Department (Updated July 2011)

Product Name
20 Degree Baume Muriatic Acid
AcTivator / 78-ACTW
AMB-100
B869 / Corrosion Inhibitor B869 / Corrosion Inhibitor A262
B885 / ClearFRAC LT B885 / ClearFRAC LT J551A
B892 / EZEFLO B892 / EZEFLO F110 Surfactant
CL-22UC
CL-28M
Clay Master 5C
Corrosion Inhibitor A261
FAW- 5
FDP-S798-05
FDP-S819-05
FE ACID
FR-48
FRW-16
FRW-18
Fracsal FR-143
Fracsal III
Fracsal NE-137
Fracsal Ultra
Fracsal Ultra-FM1
Fracsal Ultra-FM2
Fracsal Ultra-FM3
Fracsal Waterbase
Fracsal Waterbase-M1
FRW-25M
GA 8713
GBW-15L
GW-3LDF
HVG-1, Fast Hydrating Guar Slurry
ICA 400
ICP-1000
Inflo-102
Inhibisal Ultra CS-135
Inhibisal Ultra SI-141
J134L / Enzyme Breaker J134L
KCLS-2, KCL Substitute

Product Name
L065 / Scale Inhibitor L065
LP-65
Magnacide 575 Microbiocide
MSA ACID
Multifunctional Surfactant F105
Nitrogen, Refrigerated Liquid
Product 239
PS 550
S-150
SandWedge WF
SilkWater FR-A
Super TSC / Super Scale Control TSC
Super Sol 10/20/30
Ultra Breake-C
Ultra Breake-CG
Ultra Breake-M
Ultra-Breake-MG
Unislick 30 / Cyanaflo 105L
WC-5584
WCS 5177 Corrosion Scale Inhibitor
WCW219 Combination Inhibitor
WF-12B Foamer
WF-12B Salt Inhibitor Stix
WF-12B SI Foamer/Salt Inhibitor
WF12BH Foamer
WRR-5
WFR-C
XLBHT-1
XLBHT-2

Information in sections 5.4.1-3 below was compiled primarily by URS Corporation,[46] under contract to NYSERDA.

5.4.1 Properties of Fracturing Fluids

Additives are used in hydraulic fracturing operations to elicit certain properties and characteristics that would aide and enhance the operation. The desired properties and characteristics include:

- Non-reactive;
- Non-flammable;
- Minimal residuals;
- Minimal potential for scale or corrosion;
- Low entrained solids;
- Neutral pH (pH 6.5 – 7.5) for maximum polymer hydration;
- Limited formation damage;
- Appropriately modify properties of water to carry proppant deep into the shale;
- Economical to modify fluid properties; and
- Minimal environmental effects.

5.4.2 Classes of Additives

Table 5.6 lists the types, purposes and examples of additives that have been proposed to date for use in hydraulic fracturing of gas wells in New York State.

---

[46] URS, 2011, p. 2-1 & 2009, p. 2-1.

Table 5.6 - Types and Purposes of Additives Proposed for Use in New York State (Updated July 2011)

Additive Type	**Description of Purpose**	**Examples of Chemicals**[47]
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide / Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2,2-dibromo-3-nitrilopropionamide
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control /KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride Potassium chloride (KCl)
Corrosion Inhibitor (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for Oxygen Scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate salts
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillates
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid;
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol;
Solvent	Additive which is soluble in oil, water & acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol; ethoxylated alcohol

5.4.3 Composition of Fracturing Fluids

The composition of the fracturing fluid used may vary from one geologic basin or formation to another or from one area to another in order to meet the specific needs of each operation; but the

---

[47] Chemicals in brackets [ ] have not been proposed for use in the State of New York to date, but are known to be used in other states or shale formations.

range of additive types available for potential use remains the same. There are a number of different products for each additive type; however, only one product of each type is typically utilized in any given hydraulic fracturing job. The selection may be driven by the formation and potential interactions between additives. Additionally not all additive types will be utilized in every fracturing job.

Sample compositions, by weight, of fracturing fluid are provided in Figure 5.3, Figure 5.4 and Figure 5.5. The composition depicted in Figure 5.3 is based on data from the Fayetteville Shale[48] while those depicted in Figure 5.4 and Figure 5.5 are based on data from Marcellus Shale development in Pennsylvania. Based on this data, between approximately 84 and 90 percent of the fracturing fluid is water; between approximately 8 and 15 % is proppant (Photo 5.17); the remainder, typically less than 1 % consists of chemical additives listed above.

Photo 5.17 - Sand used as proppant in hydraulic fracturing operation in Bradford County, PA

---

[48] Similar to the Marcellus Shale, the Fayetteville Shale is a marine shale rich in unoxidized carbon (i.e. a black shale). The two shales are at similar depths, and vertical and horizontal wells have been drilled/fractured at both shales.

Barnett Shale is considered to be the first instance of extensive high-volume hydraulic fracturing technology use; the technology has since been applied in other areas such as the Fayetteville Shale and the Haynesville Shale. URS notes that data collected from applications to drill Marcellus Shale wells in New York indicate that the typical fracture fluid composition for operations in the Marcellus Shale is similar to the provided composition in the Fayetteville Shale. Even though no horizontal wells have been drilled in the Marcellus Shale in New York, applications filed to date as well as information provided by the industry[49] indicate that it is realistic to expect that the composition of fracture fluids used in the Marcellus Shale in New York would be similar to the fluids used in the Fayetteville Shale and the Marcellus Shale in Pennsylvania.

---

[49] ALL Consulting, 2010, p. 80.

Figure 5.3 - Sample Fracturing Fluid Composition (12 Additives), by Weight, from Fayetteville Shale[50]

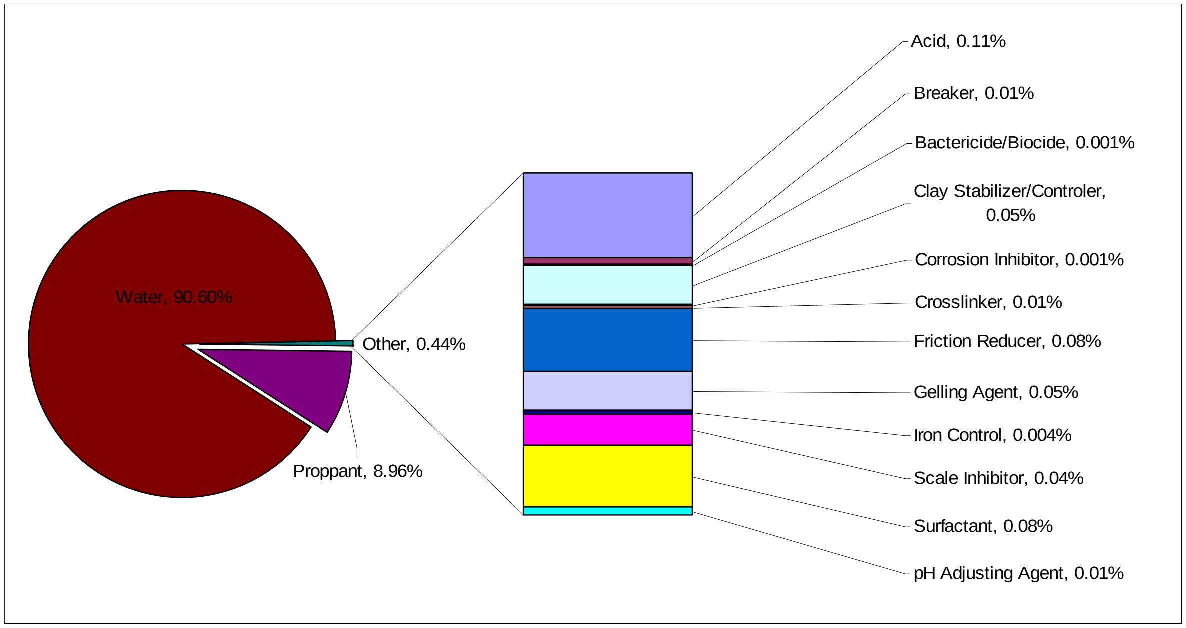
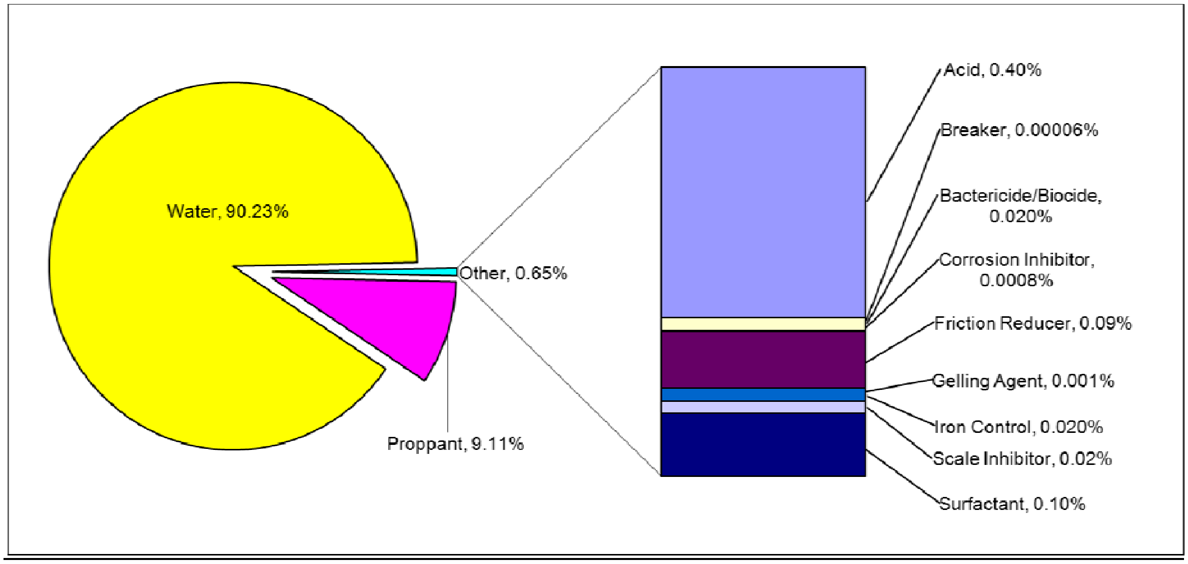


Figure 5.4 - Sample Fracturing Fluid Composition (9 Additives), by Weight, from Marcellus Shale[51] (New July 2011)

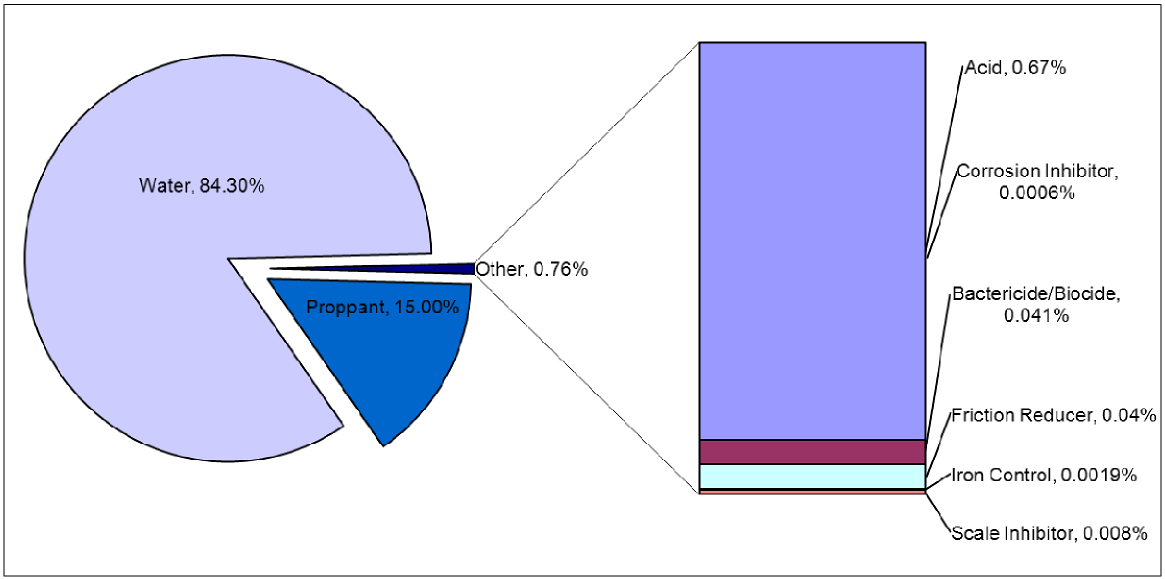


---

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

[51] URS, 2011, p. 2-4, adapted from ALL Consulting, 2010, p.81.

Figure 5.5 - Sample Fracturing Fluid Composition (6 Additives), by Weight, from Marcellus Shale[52] (New July 2011)



Each product within the 13 classes of additives may be made up of one or more chemical constituents. Table 5.7 is a list of chemical constituents and their CAS numbers, that have been extracted from product composition disclosures and MSDSs submitted to the Department for 235 products used or proposed for use in hydraulic fracturing operations in the Marcellus Shale in New York. It is important to note that several manufacturers/suppliers provide similar products (i.e., chemicals that would serve the same purpose) for any class of additive, and that not all types of additives are used in a single well.

Data provided to the Department to date indicates similar fracturing fluid compositions for vertically and horizontally drilled wells.

---

[52] URS, 2011, p.2-5, adapted from ALL Consulting, 2010, p. 81.

Table 5.7 - Chemical Constituents in Additives[53,54,55] (Updated July 2011)

CAS Number[56]	Chemical Constituent
106-24-1	(2E)-3,7-dimethylocta-2,6-dien-1-ol
67701-10-4	(C8-C18) and (C18) Unsaturated Alkylcarboxylic Acid Sodium Salt
2634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one
95-63-6	1,2,4 trimethylbenzene
93858-78-7	1,2,4-Butanetricarboxylicacid, 2-phosphono-, potassium salt
123-91-1	1,4 Dioxane
3452-07-1	1-eicosene
629-73-2	1-hexadecene
104-46-1	1-Methoxy-4-propenylbenzene
124-28-7	1-Octadecanamine, N, N-dimethyl- / N,N-Dimthyloctadecylamine
112-03-8	1-Octadecanaminium, N,N,N-Trimethyl-, Chloride /Trimethyloctadecylammonium chloride
112-88-9	1-octadecene
40623-73-2	1-Propanesulfonic acid
1120-36-1	1-tetradecene
95077-68-2	2- Propenoic acid, homopolymer sodium salt
98-55-5	2-(4-methyl-1-cyclohex-3-enyl)propan-2-ol
10222-01-2	2,2 Dibromo-3-nitrilopropionamide
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride
73003-80-2	2,2-Dobromomalonamide
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride
52-51-7	2-Bromo-2-nitro-1,3-propanediol
111-76-2	2-Butoxy ethanol / Ethylene glycol monobutyl ether / Butyl Cellusolve
1113-55-9	2-Dibromo-3-Nitriloprionamide /~~(~~2-Monobromo-3-nitriilopropionamide~~)~~
104-76-7	2-Ethyl Hexanol
67-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer
9003-03-6	2-propenoic acid, homopolymer, ammonium salt
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite

---

[53] Table 5.7, is a list of chemical constituents and their CAS numbers that have been extracted from product composition disclosures and MSDSs submitted to the Department. It was compiled by URS Corporation (2011) and was adapted by the Department to ensure that it accurately reflects the data submitted.

[54] These are the chemical constituents of all chemical additives proposed to be used in New York for hydraulic fracturing operations at shale wells. Only a few chemicals would be used in a single well; the list of chemical constituents used in an individual well would be correspondingly smaller.

[55] This list does not include chemicals that are exclusively used for drilling.

[56] Chemical Abstracts Service (CAS) is a division of the American Chemical Society. CAS assigns unique numerical identifiers to every chemical described in the literature. The intention is to make database searches more convenient, as chemicals often have many names. Almost all molecule databases today allow searching by CAS number.

CAS Number[56]	Chemical Constituent
107-19-7	2-Propyn-1-ol / Progargyl Alcohol
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,
106-22-9	3,7 - dimethyl-6-octen-1-ol
5392-40-5	3,7-_dimethyl-2,6-octadienal
115-19-5	3-methyl-1-butyn-3-ol
104-55-2	3-phenyl-2-propenal
127-41-3	4-(2,6,6-trimethyl-1-cyclohex-2-enyl)-3-buten-2-one
121-33-5	4-hydroxy-3-methoxybenzaldehyde
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol
64-19-7	Acetic acid
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine
108-24-7	Acetic Anhydride
67-64-1	Acetone
79-06-1	Acrylamide
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer
25085-02-3	Acrylamide - Sodium Acrylate Copolymer / Anionic Polyacrylamide / 2-Propanoic Acid
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride / Ethanaminium, N, N, N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, polymer with 2-propenamide (9Cl)
68891-29-2	Alcohols C8-10, ethoxylated, monoether with sulfuric acid, ammonium salt
68526-86-3	Alcohols, C11-14-iso, C13-rich
68551-12-2	Alcohols, C12-C16, Ethoxylated / Ethoxylated alcohol
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent
64743-02-8	Alkenes
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt
9016-45-9	Alkylphenol ethoxylate surfactants
1327-41-9	Aluminum chloride
68155-07-7	Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated
71011-04-6	Amines, Ditallow alkyl, ethoxylated
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates
1336-21-6	Ammonia
631-61-8	Ammonium acetate
68037-05-8	Ammonium Alcohol Ether Sulfate
7783-20-2	Ammonium bisulfate
10192-30-0	Ammonium Bisulphite
12125-02-9	Ammonium Chloride
7632-50-0	Ammonium citrate
37475-88-0	Ammonium Cumene Sulfonate
1341-49-7	Ammonium hydrogen-difluoride
6484-52-2	Ammonium nitrate
7727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate

CAS Number[56]	Chemical Constituent
1762-95-4	Ammonium Thiocyanate
12174-11-7	Attapulgite Clay
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay
71-43-2	Benzene
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide
122-91-8	Benzenemethanol,4-methoxy-, 1-formate
1300-72-7	Benzenesulfonic acid, Dimethyl-, Sodium salt /Sodium xylene sulfonate
140-11-4	Benzyl acetate
76-22-2	Bicyclo (2.2.1) heptan-2-one, 1,7,7-trimethyl-
68153-72-0	Blown lard oil amine
68876-82-4	Blown rapeseed amine
1319-33-1	Borate Salt
10043-35-3	Boric acid
1303-86-2	Boric oxide / Boric Anhydride
71-36-3	Butan-1-ol
68002-97-1	C10 - C16 Ethoxylated Alcohol
68131-39-5	C12-15 Alcohol, Ethoxylated
1317-65-3	Calcium Carbonate
10043-52-4	Calcium chloride
1305-62-0	Calcium Hydroxide
1305-79-9	Calcium Peroxide
124-38-9	Carbon Dioxide
68130-15-4	Carboxymethylhydroxypropyl guar
9012-54-8	Cellulase / Hemicellulase Enzyme
9004-34-6	Cellulose
10049-04-4	Chlorine Dioxide
78-73-9	Choline Bicarbonate
67-48-1	Choline Chloride
91-64-5	Chromen-2-one
77-92-9	Citric Acid
94266-47-4	Citrus Terpenes
61789-40-0	Cocamidopropyl Betaine
68155-09-9	Cocamidopropylamine Oxide
68424-94-2	Coco-betaine
7758-98-7	Copper (II) Sulfate
14808-60-7	Crystalline Silica (Quartz)
7447-39-4	Cupric chloride dihydrate
1490-04-6	Cyclohexanol,5-methyl-2-(1-methylethyl)
8007-02-1	Cymbopogon citratus leaf oil
8000-29-1	Cymbopogon winterianus jowitt oil
1120-24-7	Decyldimethyl Amine
2605-79-0	Decyl-dimethyl Amine Oxide

CAS Number[56]	Chemical Constituent
3252-43-5	Dibromoacetonitrile
25340-17-4	Diethylbenzene
111-46-6	Diethylene Glycol
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt
28757-00-8	Diisopropyl naphthalenesulfonic acid
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt
7398-69-8	Dimethyldiallylammonium chloride
25265-71-8	Dipropylene glycol
34590-94-8	Dipropylene Glycol Methyl Ether
139-33-3	Disodium Ethylene Diamine Tetra Acetate
64741-77-1	Distillates, petroleum, light hydrocracked
5989-27-5	D-Limonene
123-01-3	Dodecylbenzene
27176-87-0	Dodecylbenzene sulfonic acid
42504-46-1	Dodecylbenzenesulfonate isopropanolamine
50-70-4	D-Sorbitol / Sorbitol
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase
149879-98-1	Erucic Amidopropyl Dimethyl Betaine
89-65-6	Erythorbic acid, anhydrous
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer
107-21-1	Ethane-1,2-diol / Ethylene Glycol
111-42-2	Ethanol, 2,2-iminobis-
26027-38-3	Ethoxylated 4-nonylphenol
9002-93-1	Ethoxylated 4-tert-octylphenol
68439-50-9	Ethoxylated alcohol
126950-60-5	Ethoxylated alcohol
67254-71-1	Ethoxylated alcohol (C10-12)
68951-67-7	Ethoxylated alcohol (C14-15)
68439-46-3	Ethoxylated alcohol (C9-11)
66455-15-0	Ethoxylated Alcohols
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)
68439-51-0	Ethoxylated Alcohols (C12-14)
78330-21-9	Ethoxylated branch alcohol
34398-01-1	Ethoxylated C11 alcohol
78330-21-8	Ethoxylated C11-14-iso, C13-rich alcohols
61791-12-6	Ethoxylated Castor Oil
61791-29-5	Ethoxylated fatty acid, coco
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine
68439-45-2	Ethoxylated hexanol
9036-19-5	Ethoxylated octylphenol
9005-67-8	Ethoxylated Sorbitan Monostearate
9005-70-3	Ethoxylated Sorbitan Trioleate
64-17-5	Ethyl alcohol / ethanol
100-41-4	Ethyl Benzene

CAS Number[56]	Chemical Constituent
93-89-0	Ethyl benzoate
97-64-3	Ethyl Lactate
9003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)
75-21-8	Ethylene oxide
5877-42-9	Ethyloctynol
8000-48-4	Eucalyptus globulus leaf oil
61790-12-3	Fatty Acids
68604-35-3	Fatty acids, C 8-18 and C18-unsaturated compounds with diethanolamine
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea
9043-30-5	Fatty alcohol polyglycol ether surfactant
7705-08-0	Ferric chloride
7782-63-0	Ferrous sulfate, heptahydrate
50-00-0	Formaldehyde
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide
75-12-7	Formamide
64-18-6	Formic acid
110-17-8	Fumaric acid
111-30-8	Glutaraldehyde
56-81-5	Glycerol / glycerine
9000-30-0	Guar Gum
64742-94-5	Heavy aromatic petroleum naphtha
9025-56-3	Hemicellulase
7647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid
7722-84-1	Hydrogen Peroxide
64742-52-5	Hydrotreated heavy napthenic (petroleum) distillate
79-14-1	Hydroxy acetic acid
35249-89-9	Hydroxyacetic acid ammonium salt
9004-62-0	Hydroxyethyl cellulose
5470-11-1	Hydroxylamine hydrochloride
39421-75-5	Hydroxypropyl guar
35674-56-7	Isomeric Aromatic Ammonium Salt
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic
64-63-0	Isopropanol
98-82-8	Isopropylbenzene (cumene)
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline
8008-20-6	Kerosene
64742-81-0	Kerosine, hydrodesulfurized
63-42-3	Lactose
8022-15-9	Lavandula hybrida abrial herb oil
64742-95-6	Light aromatic solvent naphtha
1120-21-4	Light Paraffin Oil

CAS Number[56]	Chemical Constituent
546-93-0	Magnesium Carbonate
1309-48-4	Magnesium Oxide
1335-26-8	Magnesium Peroxide
14807-96-6	Magnesium Silicate Hydrate (Talc)
1184-78-7	methanamine, N,N-dimethyl-, N-oxide
67-56-1	Methanol
119-36-8	Methyl 2-hydroxybenzoate
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched
8052-41-3	Mineral spirits / Stoddard Solvent
64742-46-7	Mixture of severely hydrotreated and hydrocracked base oil
141-43-5	Monoethanolamine
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride
64742-48-9	Naphtha (petroleum), hydrotreated heavy
91-20-3	Naphthalene
38640-62-9	Naphthalene bis(1-methylethyl)
93-18-5	Naphthalene, 2-ethoxy-
68909-18-2	N-benzyl-alkyl-pyridinium chloride
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine
68424-94-2	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine
7727-37-9	Nitrogen, Liquid form
68412-54-4	Nonylphenol Polyethoxylate
8000-27-9	Oils, cedarwood
121888-66-2	Organophilic Clays
628-63-7	Pentyl acetate
540-18-1	Pentyl butanoate
8009-03-8	Petrolatum
64742-65-0	Petroleum Base Oil
64741-68-0	Petroleum naphtha
101-84-8	Phenoxybenzene
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt
8000-41-7	Pine Oil
8002-09-3	Pine Oils
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol
31726-34-8	Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-
9004-32-4	Polyanionic Cellulose
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized
56449-46-8	Polyethlene glycol oleate ester
9046-01-9	Polyethoxylated tridecyl ether phosphate
63428-86-4	Polyethylene glycol hexyl ether sulfate, ammonium salt
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate
9005-65-6	Polyoxyethylene Sorbitan Monooleate

CAS Number[56]	**Chemical Constituent**
61791-26-2	Polyoxylated fatty amine salt
65997-18-4	Polyphosphate
127-08-2	Potassium acetate
12712-38-8	Potassium borate
1332-77-0	Potassium borate
20786-60-1	Potassium Borate
584-08-7	Potassium carbonate
7447-40-7	Potassium chloride
590-29-4	Potassium formate
1310-58-3	Potassium Hydroxide
13709-94-9	Potassium metaborate
24634-61-5	Potassium Sorbate
112926-00-8	Precipitated silica / silica gel
57-55-6	Propane-1,2-diol, /Propylene glycol
107-98-2	Propylene glycol monomethyl ether
68953-58-2	Quaternary Ammonium Compounds
62763-89-7	Quinoline,2-methyl-, hydrochloride
62763-89-7	Quinoline,2-methyl-, hydrochloride
15619-48-4	Quinolinium, 1-(phenylmethl),chloride
8000-25-7	Rosmarinus officinalis l. leaf oil
7631-86-9	Silica, Dissolved
5324-84-5	Sodium 1-octanesulfonate
127-09-3	Sodium acetate
95371-16-7	Sodium Alpha-olefin Sulfonate
532-32-1	Sodium Benzoate
144-55-8	Sodium bicarbonate
7631-90-5	Sodium bisulfate
7647-15-6	Sodium Bromide
497-19-8	Sodium carbonate
7647-14-5	Sodium Chloride
7758-19-2	Sodium chlorite
3926-62-3	Sodium Chloroacetate
68-04-2	Sodium citrate
6381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt
2836-32-0	Sodium Glycolate
1310-73-2	Sodium Hydroxide
7681-52-9	Sodium hypochlorite
7775-19-1	Sodium Metaborate .8H_2O
10486-00-7	Sodium perborate tetrahydrate
7775-27-1	Sodium persulphate
68608-26-4	Sodium petroleum sulfonate
9003-04-7	Sodium polyacrylate
7757-82-6	Sodium sulfate
1303-96-4	Sodium tetraborate decahydrate
7772-98-7	Sodium Thiosulfate

CAS Number[56]	Chemical Constituent
1338-43-8	Sorbitan Monooleate
57-50-1	Sucrose
5329-14-6	Sulfamic acid
68442-77-3	Surfactant: Modified Amine
112945-52-5	Syntthetic Amorphous / Pyrogenic Silica / Amorphous Silica
68155-20-4	Tall Oil Fatty Acid Diethanolamine
8052-48-0	Tallow fatty acids sodium salt
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized
68647-72-3	Terpene and terpenoids
68956-56-9	Terpene hydrocarbon byproducts
533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)
75-57-0	Tetramethyl ammonium chloride
64-02-8	Tetrasodium Ethylenediaminetetraacetate
68-11-1	Thioglycolic acid
62-56-6	Thiourea
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone
68917-35-1	Thuja plicata donn ex. D. don leaf oil
108-88-3	Toluene
81741-28-8	Tributyl tetradecyl phosphonium chloride
68299-02-5	Triethanolamine hydroxyacetate
68442-62-6	Triethanolamine hydroxyacetate
112-27-6	Triethylene Glycol
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated
150-38-9	Trisodium Ethylenediaminetetraacetate
5064-31-3	Trisodium Nitrilotriacetate
7601-54-9	Trisodium ortho phosphate
57-13-6	Urea
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer
7732-18-5	Water
8042-47-5	White Mineral Oil
11138-66-2	Xanthan gum
1330-20-7	Xylene
13601-19-9	Yellow Sodium of Prussiate

Chemical Constituent
Aliphatic acids
Aliphatic alcohol glycol ether
Alkyl Aryl Polyethoxy Ethanol
Alkylaryl Sulfonate
Anionic copolymer
Aromatic hydrocarbons
Aromatic ketones
Citric acid base formula
Ethoxylated alcohol blend/mixture

Hydroxy acetic acid
Oxyalkylated alkylphenol
Petroleum distillate blend
Polyethoxylated alkanol
Polymeric Hydrocarbons
Quaternary amine
Quaternary ammonium compound
Salt of amine-carbonyl condensate
Salt of fatty acid/polyamine reaction product
Sugar
Surfactant blend
Triethanolamine

The chemical constituents listed in Table 5.7 are not linked to the product names listed in Table 5.4 and Table 5.5 because a significant number of product compositions have been properly justified as trade secrets within the coverage of disclosure exceptions of the Freedom of Information Law [Public Officers Law §87.2(d)] and the Department's implementing regulation, 6 NYCRR § 616.7. The Department however, considers MSDSs to be public information ineligible for exception from disclosure as trade secrets or confidential business information.

5.4.3.1 Chemical Categories and Health Information

The Department requested assistance from NYSDOH in identifying potential exposure pathways and constituents of concern associated with high-volume hydraulic fracturing for low-permeability gas reservoir development. The Department provided DOH with fracturing additive product constituents based on MSDSs and product-composition disclosures for hydraulic fracturing additive products that were provided by well-service companies and the chemical supply companies that manufacture the products.

Compound-specific toxicity data are very limited for many chemical additives to fracturing fluids, so chemicals potentially present in fracturing fluids were grouped together into categories according to their chemical structure (or function in the case of microbiocides) in Table 5.8, compiled by NYSDOH. As explained above, any given individual fracturing job will only involve a handful of chemicals and may not include every category of chemicals.

Table 5.8 - Categories based on chemical structure of potential fracturing fluid constituents.[57] (Updated July 2011)

Chemical	CAS Number
Amides	
Formamide	75-12-7
acrylamide	79-06-1
Amides, C8-18 and C19-Unsatd., N,N-Bis(hydroxyethyl)	68155-07-7
Amines	
urea	57-13-6
thiourea	62-56-6
Choline chloride	67-48-1
tetramethyl ammonium chloride	75-57-0
Choline Bicarbonate	78-73-9
Ethanol, 2,2-Iminobis-	111-42-2
1-Octadecanaminium, N,N,N, Trimethyl-, Chloride (aka Trimethyloctadecylammonium choride)	112-03-8
1-Octadecanamine, N,N-Dimethyl- (aka N,N-Dimethyloctadecylamine)	124-28-7
monoethanolamine	141-43-5
Decyldimethyl Amine	1120-24-7
methanamine, N,N-dimethyl-, N-oxide	1184-78-7
Decyl-dimethyl Amine Oxide	2605-79-0
dimethyldiallylammonium chloride	7398-69-8
polydimethyl dially ammonium chloride	26062-79-3
dodecylbenzenesulfonate isopropanolamine	42504-46-1
N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	44992-01-0
2-acryloyloxyethyl(benzyl)dimethylammonium chloride	46830-22-2
ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	54076-97-0
Cocamidopropyl Betaine	61789-40-0
Quaternary Ammonium Chloride	61789-71-7
polyoxylated fatty amine salt	61791-26-2
quinoline, 2-methyl, hydrochloride	62763-89-7
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68139-30-0
tall oil fatty acid diethanolamine	68155-20-4
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68424-94-2
amines, tallow alkyl, ethoxylated, acetates	68551-33-7
quaternary ammonium compounds, bis(hydrogenated tallow alkyl) dimethyl, salts with bentonite	68953-58-2

---

[57] The chemicals listed in this table are organized in order of ascending CAS Number by category.

Chemical	CAS Number
amines, ditallow alkyl, ethoxylated	71011-04-6
amines, C-12-14-tert-alkyl, ethoxylated	73138-27-9
benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	74153-51-8
Erucic Amidopropyl Dimethyl Betaine	149879-98-1
Petroleum Distillates	
light paraffin oil	1120-21-4
kerosene	8008-20-6
Petrolatum	8009-03-8
White Mineral Oil	8042-47-5
stoddard solvent	8052-41-3
Distillates, petroleum, light hydrocracked	64741-77-1
petroleum naphtha	64741-68-0
Mixture of severely hydrotreated and hydrocracked base oil	64742-46-7
Multiple names listed under same CAS#: LVP aliphatic hydrocarbon, hydrotreated light distillate, low odor paraffin solvent, paraffin solvent, paraffinic napthenic solvent, isoparaffinic solvent, distillates (petroleum) hydrotreated light, petroleum light distillate, aliphatic hydrocarbon, petroleum distillates, mixture of severely hydrotreated and hydrocracked base oil	64742-47-8
naphtha, hydrotreated heavy	64742-48-9
Multiple names listed under same CAS#: hydrotreated heavy napthenic distillate, Petroleum distillates	64742-52-5
petroleum base oil	64742-65-0
kerosine (petroleum, hydrodesulfurized)	64742-81-0
kerosine (petroleum, hydrodesulfurized)	64742-88-7
Multiple names listed under same CAS#: heavy aromatic petroleum naphtha, light aromatic solvent naphtha	64742-94-5
light aromatic solvent naphtha	64742-95-6
alkenes, C> 10 α-	64743-02-8
Aromatic Hydrocarbons	
benzene	71-43-2
naphthalene	91-20-3
naphthalene, 2-ethoxy	93-18-5

Chemical	CAS Number
1,2,4-trimethylbenzene	95-63-6
cumene	98-82-8
ethyl benzene	100-41-4
toluene	108-88-3
dodecylbenzene	123-01-3
xylene	1330-20-7
diethylbenzene	25340-17-4
naphthalene bis(1-methylethyl)	38640-62-9
Alcohols & Aldehydes	
formaldehyde	50-00-0
sorbitol (or) D-sorbitol	50-70-4
Glycerol	56-81-5
propylene glycol	57-55-6
ethanol	64-17-5
isopropyl alcohol	67-63-0
methanol	67-56-1
isopropyl alcohol	67-63-0
butanol	71-36-3
2-(4-methyl-1-cyclohex-3-enyl)propan-2-ol	98-55-5
3-phenylprop-2-enal	104-55-2
2-ethyl-1-hexanol	104-76-7
3,7 - dimethyloct-6-en-1-ol	106-22-9
(2E)-3,7-dimethylocta-2,6-dien-1-ol	106-24-1
propargyl alcohol	107-19-7
ethylene glycol	107-21-1
Diethylene Glycol	111-46-6
3-methyl-1-butyn-3-ol	115-19-5
4-hydroxy-3-methyoxybenzaldehyde	121-33-5
5-methyl-2-propan-2-ylcyclohexan-1-ol	1490-04-6
3,7-dimethylocta-2,6-dienal	5392-40-5
Ethyloctynol	5877-42-9
Glycol Ethers, Ethoxylated Alcohols & Other Ethers	
phenoxybenzene	101-84-8
1-methyoxy-4-prop-1-enylbenzene	104-46-1
propylene glycol monomethyl ether	107-98-2
ethylene glycol monobutyl ether	111-76-2

Chemical	CAS Number
triethylene glycol	112-27-6
ethoxylated 4-tert-octylphenol	9002-93-1
ethoxylated sorbitan trioleate	9005-70-3
Polysorbate 80	9005-65-6
ethoxylated sorbitan monostearate	9005-67-8
Polyethylene glycol-(phenol) ethers	9016-45-9
Polyethylene glycol-(phenol) ethers	9036-19-5
fatty alcohol polyglycol ether surfactant	9043-30-5
Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-	24938-91-8
Dipropylene glycol	25265-71-8
Nonylphenol Ethoxylate	26027-38-3
crissanol A-55	31726-34-8
Polyethylene glycol-(alcohol) ethers	34398-01-1
dipropylene glycol methyl ether	34590-94-8
Trimethylolpropane, Ethoxylated, Propoxylated	52624-57-4
Polyethylene glycol-(alcohol) ethers	60828-78-6
Ethoxylated castor oil [PEG-10 Castor oil]	61791-12-6
ethoxylated alcohols	66455-15-0
ethoxylated alcohol	67254-71-1
Ethoxylated alcohols (9 – 16 carbon atoms)	68002-97-1
ammonium alcohol ether sulfate	68037-05-8
Polyethylene glycol-(alcohol) ethers	68131-39-5
Polyethylene glycol-(phenol) ethers	68412-54-4
ethoxylated hexanol	68439-45-2
Polyethylene glycol-(alcohol) ethers	68439-46-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68439-50-9
C12-C14 ethoxylated alcohols	68439-51-0
Exxal 13	68526-86-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68551-12-2
alcohols, C-14-15, ethoxylated	68951-67-7
Ethoxylated C11-14-iso, C13-rich alcohols	78330-21-8
Ethoxylated Branched C11-14, C-13-rich Alcohols	78330-21-9
Ethoxylated alcohols (9 – 16 carbon atoms)	84133-5-6
alcohol ethoxylated	126950-60-5
Polyethylene glycol-(phenol) ethers	127087-87-0
Microbiocides	
bronopol	52-51-7

Chemical	CAS Number
glutaraldehyde	111-30-8
2-monobromo-3-nitrilopropionamide	1113-55-9
1,2-benzisothiazolin-3-one	2634-33-5
dibromoacetonitrile	3252-43-5
dazomet	533-74-4
Hydrogen Peroxide	7722-84-1
2,2-dibromo-3-nitrilopropionamide	10222-01-2
tetrakis	55566-30-8
2,2-dibromo-malonamide	73003-80-2
Organic Acids, Salts, Esters and Related Chemicals	
tetrasodium EDTA	64-02-8
formic acid	64-18-6
acetic acid	64-19-7
sodium citrate	68-04-2
thioglycolic acid	68-11-1
hydroxyacetic acid	79-14-1
erythorbic acid, anhydrous	89-65-6
ethyl benzoate	93-89-0
ethyl lactate	97-64-3
acetic anhydride	108-24-7
fumaric acid	110-17-8
ethyl 2-hydroxybenzoate	118-61-6
methyl 2-hydroxybenzoate	119-36-8
(4-methoxyphenyl) methyl formate	122-91-8
potassium acetate	127-08-2
sodium acetate	127-09-3
Disodium Ethylene Diamine Tetra Acetate	139-33-3
benzyl acetate	140-11-4
Trisodium Ethylenediamine tetraacetate	150-38-9
sodium benzoate	532-32-1
pentyl butanoate	540-18-1
potassium formate	590-29-4
pentyl acetate	628-63-7
ammonium acetate	631-61-8
Benzenesulfonic acid, Dimethyl-, Sodium salt (aka Sodium xylene sulfonate)	1300-72-7
Sodium Glycolate	2836-32-0
Sodium Chloroacetate	3926-62-3

Chemical	CAS Number
trisodium nitrilotriacetate	5064-31-3
sodium 1-octanesulfonate	5324-84-5
Sodium Erythorbate	6381-77-7
ammonium citrate	7632-50-0
tallow fatty acids sodium salt	8052-48-0
Polyethoxylated tridecyl ether phosphate	9046-01-9
quinolinium, 1-(phenylmethyl), chloride	15619-48-4
diethylenetriamine penta (methylenephonic acid) sodium salt	22042-96-2
potassium sorbate	24634-61-5
dodecylbenzene sulfonic acid	27176-87-0
diisopropyl naphthalenesulfonic acid	28757-00-8
hydroxyacetic acid ammonium salt	35249-89-9
isomeric aromatic ammonium salt	35674-56-7
ammonium cumene sulfonate	37475-88-0
Fatty Acids	61790-12-3
Fatty acids, coco, reaction products with ethanolamine, ethoxylated	61791-08-0
fatty acid, coco, ethoxylated	61791-29-5
2-propenoic acid, telomer with sodium hydrogen sulfite	66019-18-9
fatty acides, c8-18 and c18-unsatd., sodium salts	67701-10-4
carboxymethylhydroxypropyl guar	68130-15-4
Blown lard oil amine	68153-72-0
Tall oil Fatty Acid Diethanolamine	68155-20-8
fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	68188-40-9
triethanolamine hydroxyacetate	68299-02-5
alkyl (C14-C16) olefin sulfonate, sodium salt	68439-57-6
triethanolamine hydroxyacetate	68442-62-6
Modified Amine	68442-77-3
fatty acids, c-18-18 and c18-unsatd., compds with diethanolamine	68604-35-3
Sodium petroleum sulfonate	68608-26-4
Blown rapeseed amine	68876-82-4
Poly(oxy-1,2-ethanediyl), α-sulfo-ω-hydroxy-, c8-10-alkyl ethers, ammonium salts	68891-29-2
N-benzyl-alkyl-pyridinium chloride	68909-18-2
phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis (methylene)]]tetrakis-ammonium salt	70714-66-8
tributyl tetradecyl phosphonium chloride	81741-28-8
2-Phosphonobutane-1,2,4-tricarboxylic acid, potassium salt	93858-78-7
sodium alpha-olefin sulfonate	95371-16-7
benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	119345-04-9

Chemical	CAS Number
Polymers	
guar gum	9000-30-0
guar gum	9000-30-01
2-propenoic acid, homopolymer, ammonium salt	9003-03-6
low mol wt polyacrylate	9003-04-7
Low Mol. Wt. Polyacrylate	9003-04-7
Multiple names listed under same CAS#: oxirane, methyl-, polymer with oxirane, Ethylene Glycol-Propylene Glycol Copolymer	9003-11-6
Polyanionic Cellulose	9004-32-4
cellulose	9004-34-6
hydroxyethyl cellulose	9004-62-0
cellulase/hemicellulase enzyme	9012-54-8
hemicellulase	9025-56-3
xanthan gum	11138-66-2
acrylamide-sodium acrylate copolymer	25085-02-3
Vinylidene Chloride/Methylacrylate Copolymer	25038-72-6
polyethylene glycol	25322-68-3
copolymer of acrylamide and sodium acrylate	25987-30-8
formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	29316-47-0
hemicellulase	37288-54-3
acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	38193-60-1
TerPoly (Acrylamide-AMPS Acrylic Acid)	40623-73-2
oxiranemthanaminium, N,N,N-trimethyl-, chloride, homopolymer (aka: polyepichlorohydrin, trimethylamine quaternized)	51838-31-4
polyethlene glycol oleate ester	56449-46-8
polymer with 2-propenoic acid and sodium 2-propenoate	62649-23-4
modified thiourea polymer	68527-49-1
methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	68891-11-2
acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	69418-26-4
2-propenoic acid, polymer with sodium phosphinate (1:1)	71050-62-9
2- Propenoic acid, homopolymer sodium salt	95077-68-2
formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	153795-76-7
Minerals, Metals and other Inorganics	
carbon dioxide	124-38-9
sodium bicarbonate	144-55-8
Sodium Carbonate	497-19-8
Magnesium Carbonate	546-93-0

Chemical	CAS Number
Potassium Carbonate	584-08-7
Boric Anhydride (a.k.a. Boric Oxide)	1303-86-2
sodium tetraborate decahydrate	1303-96-4
Calcium Hydroxide	1305-62-0
Calcium Peroxide	1305-79-9
Magnesium Oxide	1309-48-4
Potassium Hydroxide	1310-58-3
sodium hydroxide	1310-73-2
Calcium Carbonate	1317-65-3
Borate Salt	1319-33-1
aluminum chloride, basic	1327-41-9
Magnesium Peroxide	1335-26-8
sodium tetraborate decahydrate	1332-77-0
aqua ammonia 29.4%	1336-21-6
ammonium hydrogen-difluoride	1341-49-7
ammonium thiocyanate	1762-95-4
sulfamic acid	5329-14-6
hydroxylamine hydrochloride	5470-11-1
ammonium nitrate	6484-52-2
cupric chloride dihydrate	7447-39-4
potassium chloride	7447-40-7
Trisodium ortho phosphate	7601-54-9
Non-Crystaline Silica	7631-86-9
sodium bisulfate	7631-90-5
hydrochloric acid	7647-01-0
sodium chloride	7647-14-5
sodium bromide	7647-15-6
aqueous ammonia	7664-41-7
sodium hypochlorite	7681-52-9
ferric chloride	7705-08-0
nitrogen	7727-37-9
ammonium persulfate	7727-54-0
water	7732-18-5
sodium sulfate	7757-82-6
sodium chlorite	7758-19-2
sodium thiosulfate	7772-98-7
Sodium Metaborate.8H2O	7775-19-01
Sodium Persulphate	7775-27-1

Chemical	CAS Number
ferrous sulfate, heptahydrate	7782-63-0
ammonium bisulfate	7783-20-2
boric acid	10043-35-3
Calcium Chloride	10043-52-4
Chlorine Dioxide	10049-04-4
ammonium bisulphite	10192-30-0
sodium perborate tetrahydrate	10486-00-7
ammonium chloride	12125-02-9
Attapulgite Clay	12174-11-7
potassium borate	12714-38-8
Yellow Sodium of Prussiate	13601-19-9
potassium metaborate	13709-94-9
Magnesium Silicate Hydrate (Talc)	14807-96-6
crystalline silica (quartz)	14808-60-7
glassy calcium magnesium phosphate	65997-17-3
Polyphosphate	65997-18-4
silica gel	112926-00-8
synthetic amorphous, pyrogenic silica	112945-52-5
synthetic amorphous, pyrogenic silica	121888-66-2
Miscellaneous	
Sucrose	57-50-1
lactose	63-42-3
acetone	67-64-1
ethylene oxide	75-21-8
1,7,7-trimethylbicyclo[2.2.1]heptan-2one	76-22-2
chromen-2-one	91-64-5
1-octadecene	112-88-9
1,4-dioxane	123-91-1
(E)-4-(2,6,6-trimethyl-1-cyclohex-2-enyl)but-3-en-2-one	127-41-3
1-hexadecene	629-73-2
1-tetradecene	1120-36-1
sorbitan monooleate	1338-43-8
1-eicosene	3452-07-1
D-Limonene	5989-27-5
rosmarinus officinalis l. leaf oil	8000-25-7
oils, cedarwood	8000-27-9
cymbopogan winterianus jowitt oil	8000-29-1

Chemical	CAS Number
Pine Oil	8000-41-7
eucalyptus globulus leaf oil	8000-48-4
oils, pine	8002-09-3
cymbopogon citratus leaf oil	8007-02-1
lavandula hydrida abrial herb oil	8022-15-9
2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	27776-21-2
3,5,7-triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride	51229-78-8
alkenes	64743-02-8
Cocamidopropyl Oxide	68155-09-9
terpene and terpenoids	68647-72-3
thuja plicata donn ex. D. don leaf oil	68917-35-1
terpene hydrocarbon byproducts	68956-56-9
tar bases, quinoline derivs., benzyl chloride-quaternized	72780-70-7
citrus terpenes	94266-47-4
organophilic clays	121888-68-4
Listed without CAS Number[58]	
belongs with amines	
proprietary quaternary ammonium compounds	NA
quaternary ammonium compound	NA
triethanolamine (tea) 85%, drum	NA
Quaternary amine	NA
Fatty amidoalkyl betaine	NA
belongs with petroleum distillates	
petroleum distillate blend	NA
belongs with aromatic hydrocarbons	
aromatic hydrocarbon	NA
aromatic ketones	NA
belongs with glycol ethers, ethoxylated alcohols & other ethers	
Acetylenic Alcohol	NA
Aliphatic Alcohols, ethoxylated	NA
Aliphatic Alcohol glycol ether	NA
Ethoxylated alcohol linear	NA
Ethoxylated alcohols	NA
aliphatic alcohol polyglycol ether	NA

---

[58] Constituents listed without CAS #'s were tentatively placed in chemical categories based on the name listed on the MSDS or within confidential product composition disclosures. Many of the constituents reported without CAS #s, are mixtures which require further disclosure to the Department.

Chemical	CAS Number
alkyl aryl polyethoxy ethanol	NA
mixture of ethoxylated alcohols	NA
nonylphenol ethoxylate	NA
oxyalkylated alkylphenol	NA
polyethoxylated alkanol	NA
Oxyalkylated alcohol	NA
belongs with organic acids, salts, esters and related chemicals	
Aliphatic acids derivative	NA
Aliphatic Acids	NA
hydroxy acetic acid	NA
citric acid 50%, base formula	NA
Alkylaryl Sulfonate	NA
belongs with polymers	
hydroxypropyl guar	NA
2-acrylamido-2-methylpropanesulphonic acid sodium salt polymer	NA
Anionic copolymer	NA
Anionic polymer	NA
belongs with minerals, metals and other inorganics	
precipitated silica	NA
sodium hydroxide	NA
belongs with miscellaneous	
epa inert ingredient	NA
non-hazardous ingredients	NA
proprietary surfactant	NA
salt of fatty acid/polyamine reaction product	NA
salt of amine-carbonyl condensate	NA
surfactant blend	NA
sugar	NA
polymeric hydrocarbon mixture	NA
water and inert ingredients	NA

Although exposure to fracturing additives would not occur absent a failure of operational controls such as an accident, a spill or other non-routine incident, the health concerns noted by NYSDOH for each chemical category are discussed below. The discussion is based on available qualitative hazard information for chemicals from each category. Qualitative descriptions of potential health concerns discussed below generally apply to all exposure routes (i.e., ingestion, inhalation or skin contact) unless a specific exposure route is mentioned. For most chemical categories, health information is available for only some of the chemicals in the category. Toxicity testing data is quite limited for some chemicals, and less is known about their potential adverse effects. In particular, there is little meaningful information one way or the other about the potential impact on human health of chronic low level exposures to many of these chemicals, as could occur if an aquifer were to be contaminated as the result of a spill or release that is undetected and/or unremediated.

The overall risk of human health impacts occurring from hydraulic fracturing would depend on whether any human exposure occurs, such as, for example, in the event of a spill. If an actual contamination event such as a spill were to occur, more specific assessment of health risks would require obtaining detailed information specific to the event such as the specific additives being used and site-specific information about exposure pathways and environmental contaminant levels. Potential human health risks of a specific event would be assessed by comparison of case-specific data with existing drinking water standards or ambient air guidelines.[59] If needed, other chemical-specific health comparison values would be developed, based on a case-specific review of toxicity literature for the chemicals involved. A case-specific assessment would include information on how potential health effects might differ (both qualitatively and quantitatively) depending on the route of exposure.

Petroleum Distillate Products

Petroleum-based constituents are included in some fracturing fluid additive products. They are listed in MSDSs as various petroleum distillate fractions including kerosene, petroleum naphtha, aliphatic hydrocarbon, petroleum base oil, heavy aromatic petroleum naphtha, mineral spirits, hydrotreated light petroleum distillates, stoddard solvent or aromatic hydrocarbon. These can be found in a variety of additive products including corrosion inhibitors, friction reducers and solvents. Petroleum distillate products are mixtures that vary in their composition, but they have similar adverse health effects. Accidental ingestion that results in exposure to large amounts of petroleum distillates is associated with adverse effects on the gastrointestinal system and central nervous system. Skin contact with kerosene for short periods can cause skin irritation, blistering or peeling. Breathing petroleum distillate vapors can adversely affect the central nervous system.

---

[59] 10 NYCRR Part 5: Drinking Water Supplies; Subpart 5-1: Public Water Systems, Maximum Contaminant Levels; Department Policy DAR-1: Guidelines for the Control of Toxic Ambient Air Contaminants.

Aromatic Hydrocarbons

Some fracturing additive products contain specific aromatic hydrocarbon compounds that can also occur in petroleum distillates (benzene, toluene, ethylbenzene and xylenes or BTEX; naphthalene and related derivatives, trimethylbenzene, diethylbenzene, dodecylbenzene, cumene). BTEX compounds are associated with adverse effects on the nervous system, liver, kidneys and blood-cell-forming tissues. Benzene has been associated with an increased risk of leukemia in industrial workers who breathed elevated levels of the chemical over long periods of time in workplace air. Exposure to high levels of xylene has damaged the unborn offspring of laboratory animals exposed during pregnancy. Naphthalene is associated with adverse effects on red blood cells when people consumed naphthalene mothballs or when infants wore cloth diapers stored in mothballs. Laboratory animals breathing naphthalene vapors for their lifetimes had damage to their respiratory tracts and increased risk of nasal and lung tumors.

Glycols

Glycols occur in several fracturing fluid additives including crosslinkers, breakers, clay and iron controllers, friction reducers and scale inhibitors. Propylene glycol has low inherent toxicity and is used as an additive in food, cosmetic and drug products. However, high exposure levels of ethylene glycol adversely affect the kidneys and reproduction in laboratory animals.

Glycol Ethers

Glycol ethers and related ethoxylated alcohols and phenols are present in fracturing fluid additives, including corrosion inhibitors, surfactants and friction reducers. Some glycol ethers [e.g., monomethoxyethanol, monoethoxyethanol, propylene glycol monomethyl ether, ethylene glycol monobutyl ether (also known as 2-butoxyethanol)] can affect the male reproductive system and red blood cell formation in laboratory animals at high exposure levels.

Alcohols and Aldehydes

Alcohols are present in some fracturing fluid additive products, including corrosion inhibitors, foaming agents, iron and scale inhibitors and surfactants. Exposure to high levels of some alcohols (e.g., ethanol, methanol) affects the central nervous system.

Aldehydes are present in some fracturing fluid additive products, including corrosion inhibitors, scale inhibitors, surfactants and foaming agents. Aldehydes can be irritating to tissues when coming into direct contact with them. The most common symptoms include irritation of the skin, eyes, nose and throat, along with increased tearing. Formaldehyde is present in several additive products, although in most cases the concentration listed in the product is relatively low (< 1%) and is listed alongside a formaldehyde-based polymer constituent. Severe pain, vomiting, coma and possibly death can occur after drinking large amounts of formaldehyde. Several studies of laboratory rats exposed for life to high amounts of formaldehyde in air found that the rats developed nose cancer. Some studies of humans exposed to lower amounts of formaldehyde in workplace air found more cases of cancer of the nose and throat (nasopharyngeal cancer) than expected, but other studies have not found nasopharyngeal cancer in other groups of workers exposed to formaldehyde in air.

Amides

Acrylamide is used in some fracturing fluid additives to create polymers during the stimulation process. These polymers are part of some friction reducers and scale inhibitors. Although the reacted polymers that form during fracturing are of low inherent toxicity, unreacted acrylamide may be present in the fracturing fluid, or breakdown of the polymers could release acrylamide back into the flowback water. High levels of acrylamide damage the nervous system and reproductive system in laboratory animals and also cause cancer in laboratory animals.

Formamide may be used in some corrosion inhibitors products. Ingesting high levels of formamide adversely affects the female reproductive system in laboratory animals.

Amines

Amines are constituents of fracturing fluid products including corrosion inhibitors, cross-linkers, friction reducers, iron and clay controllers and surfactants. Chronic ingestion of mono-, di- or tri-ethanolamine adversely affects the liver and kidneys of laboratory animals.

Some quaternary ammonium compounds, such as dimethyldiallyl ammonium chloride, can react with chemicals used in some systems for drinking water disinfection to form nitrosamines. Nitrosamines cause genetic damage and cancer when ingested by laboratory animals.

Organic Acids, Salts, Esters and Related Chemicals

Organic acids and related chemicals are constituents of fracturing fluid products including acids, buffers, corrosion and scale inhibitors, friction reducers, iron and clay controllers, solvents and surfactants. Some short-chain organic acids such as formic, acetic and citric acids can be corrosive or irritating to skin and mucous membranes at high concentrations. However, acetic and citric acids are regularly consumed in foods (such as vinegar and citrus fruits) where they occur naturally at lower levels that are not harmful.

Some foaming agents and surfactant products contain organic chemicals included in this category that contain a sulfonic acid group (sulfonates). Exposure to elevated levels of sulfonates is irritating to the skin and mucous membranes.

Microbiocides

Microbiocides are antimicrobial pesticide products intended to inhibit the growth of various types of bacteria in the well. A variety of different chemicals are used in different microbiocide products that are proposed for Marcellus wells. Toxicity information is limited for several of the microbiocide chemicals. However, for some, high exposure has caused effects in the respiratory and gastrointestinal tracts, the kidneys, the liver and the nervous system in laboratory animals.

Other Constituents

The remaining chemicals listed in MSDSs and confidential product composition disclosures provided to the Department are included in Table 5.8 under the following categories: polymers, miscellaneous chemicals that did not fit another chemical category and product constituents that were not identified by a CAS number. Readily available health effects information is lacking for many of these constituents, but one that is relatively well studied is discussed here. In the event of environmental contamination involving chemicals lacking readily available health effects information, the toxicology literature would have to be researched for chemical-specific toxicity data or toxicity data for closely- related chemicals.

1,4-dioxane may be used in some surfactant products. 1,4-Dioxane is irritating to the eyes and nose when vapors are breathed. Exposure to very high levels may cause severe kidney and liver effects and possibly death. Studies in animals have shown that breathing vapors of 1,4-dioxane, swallowing liquid 1,4-dioxane or contaminated drinking water, or having skin contact with liquid 1,4-dioxane affects mainly the liver and kidneys. Laboratory rats and mice that drank water containing 1,4-dioxane during most of their lives developed liver cancer; the rats also developed cancer inside the nose.

Conclusions

The hydraulic fracturing product additives proposed for use in NYS and used for fracturing horizontal Marcellus Shale wells in other states contain similar types of chemical constituents as the products that have been used for many years for hydraulic fracturing of traditional vertical wells in NYS. Some of the same products are used in both well types. Chemicals in products proposed for use in high-volume hydraulic fracturing include some that, based mainly on occupational studies or high-level exposures in laboratory animals, have been shown to cause effects such as carcinogenicity, mutagenicity, reproductive toxicity, neurotoxicity or organ damage. This information only indicates the types of toxic effects these chemicals can cause under certain circumstances but does not mean that use of these chemicals would cause exposure in every case or that exposure would cause those effects in every case. Whether or not people actually experience a toxic effect from a chemical depends on whether or not they experience any exposure to the chemical along with many other factors including, among others, the amount, timing, duration and route of exposure and individual characteristics that can contribute to differences in susceptibility.

The total amount of fracturing additives and water used in hydraulic fracturing of horizontal wells is considerably larger than for traditional vertical wells. This suggests the potential environmental consequences of an upset condition could be proportionally larger for horizontal well drilling and fracturing operations. As mentioned earlier, the 1992 GEIS addressed hydraulic fracturing in Chapter 9, and NYSDOH's review did not identify any potential exposure scenarios associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the 1992 GEIS.

5.5 Transport of Hydraulic Fracturing Additives

Fracturing additives are transported in "DOT-approved" trucks or containers. The trucks are typically flat-bed trucks that carry a number of strapped-on plastic totes which contain the liquid additive products. (Totes are further described in Section 5.6.). Liquid products used in smaller quantities are transported in one-gallon sealed jugs carried in the side boxes of the flat-bed. Some liquid constituents, such as hydrochloric acid, are transferred in tank trucks.

Dry additives are transported on flat-beds in 50- or 55-pound bags which are set on pallets containing 40 bags each and shrink-wrapped, or in five-gallon sealed plastic buckets. When smaller quantities of some dry products such as powdered biocides are used, they are contained in a double-bag system and may be transported in the side boxes of the truck that constitutes the blender unit.

Regulations that reference "DOT-approved" trucks or containers that are applicable to the transportation and storage of hazardous fracturing additives refer to federal (USDOT) regulations for registering and permitting commercial motor carriers and drivers, and established standards for hazardous containers. The United Nations (UN) also has established standards and criteria for containers. New York is one of many states where the state agency (NYSDOT) has adopted the federal regulations for transporting hazardous materials interstate. The NYSDOT has its own requirements for intrastate transportation.[60] For informational purposes, Chapter 8 contains descriptions of applicable NYSDOT and USDOT regulations.

Transporting fracturing additives that are hazardous is comprehensively regulated under existing regulations. The regulated materials include the hazardous additives and mixtures containing threshold levels of hazardous materials. These transported materials are maintained in the USDOT or UN-approved storage containers until the materials are consumed at the drill sites.[61]

5.6 On-Site Storage and Handling of Hydraulic Fracturing Additives

Prior to use, additives remain at the wellsite in the containers and on the trucks in which they are transported and delivered. Storage time is generally less than a week for economic and logistical reasons, materials are not delivered until fracturing operations are set to commence, and only the amount needed for scheduled continuous fracturing operations is delivered at any one time.

---

[60] Alpha 2009, p. 31.

[61] Alpha 2009, p. 31.

As detailed in Section 5.4.3, there are 13 classes of additives, based on their purpose or use; not all classes would be used at every well; and only one product in each class would typically be used per job. Therefore, although the chemical lists in Table 5.7 and Table 5.8 reflect the constituents of 235 products, typically no more than 12 products consisting of far fewer chemicals than listed would be present at one time at any given site.

When the hydraulic fracturing procedure commences, hoses are used to transfer liquid additives from storage containers to a truck-mounted blending unit. The flat-bed trucks that deliver liquid totes to the site may be equipped with their own pumping systems for transferring the liquid additive to the blending unit when fracturing operations are in progress. Flat-beds that do not have their own pumps rely on pumps attached to the blending unit. Additives delivered in tank trucks are pumped to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is not stored, but is immediately mixed with proppant and pumped into the cased and cemented wellbore. This process is conducted and monitored by qualified personnel, and devices such as manual valves provide additional controls when liquids are transferred. Common observed practices during visits to drill sites in the northern tier of Pennsylvania included lined containments and protective barriers where chemicals were stored and blending took place.[62]

5.6.1 Summary of Additive Container Types

The most common containers are 220-gallon to 375-gallon high-density polyethylene (HDPE) totes, which are generally cube-shaped and encased in a metal cage. These totes have a bottom release port to transfer the chemicals, which is closed and capped during transport, and a top fill port with a screw-on cap and temporary lock mechanism. Photo 5.18 depicts a transport truck with totes.

---

[62] Alpha, 2009, p. 35.

Photo 5.18 - Transport trucks with totes

To summarize, the storage containers at any given site during the short period of time between delivery and completion of continuous fracturing operations will consist of all or some of the following:

- Plastic totes encased in metal cages, ranging in volume from 220 gallons to 375 gallons, which are strapped on to flat bed trucks pursuant to USDOT and NYSDOT regulations;
- Tank trucks;
- Palletized 50-55 gallon bags, made of coated paper or plastic (40 bags per pallet, shrink-wrapped as a unit and then wrapped again in plastic);
- One-gallon jugs with perforated sealed twist lids stored inside boxes on the flat-bed; and
- Smaller double-bag systems stored inside boxes on the blending unit.

5.7 Source Water for High-Volume Hydraulic Fracturing

As discussed in Chapter 6, it is estimated, based on water withdrawals in the Susquehanna River Basin in Pennsylvania, that average water use per well in New York could be 3.6 million gallons. Operators could withdraw water from surface or ground water sources themselves or may purchase it from suppliers. The suppliers may include, among others, municipalities with excess capacity in their public supply systems, or industrial entities with wastewater effluent streams that meet usability criteria for hydraulic fracturing. Potential environmental impacts of water sourcing are discussed in Chapter 6, and mitigation measures to address potential environmental impacts are discussed in Chapter 7. Photos 5.19 a and b depict a water withdrawal facility along the Chemung River in the northern tier of Pennsylvania.

Factors affecting usability of a given source include:[63]

Availability – The "owner" of the source needs to be identified, contact made, and agreements negotiated.

Distance/route from the source to the point of use – The costs of trucking large quantities of water increases and water supply efficiency decreases when longer distances and travel times are involved. Also, the selected routes need to consider roadway wear, bridge weight limits, local zoning limits, impacts on residents, and related traffic concerns.

Available quantity – Use of fewer, larger water sources avoids the need to utilize multiple smaller sources.

Reliability – A source that is less prone to supply fluctuations or periods of unavailability would be more highly valued than an intermittent and less steady source.

Accessibility –Water from deep mines and saline aquifers may be more difficult to access than a surface water source unless adequate infrastructure is in place. Access to a municipal or industrial plant or reservoir may be inconvenient due to security or other concerns. Access to a stream may be difficult due to terrain, competing land uses, or other issues.

---

[63] URS, 2009, p. 7-1.

Quality of water – The fracturing fluid serves a very specific purpose at different stages of the fracturing process. The composition of the water could affect the efficacy of the additives and equipment used. The water may require pre-treatment or additional additives may be needed to overcome problematic characteristics.

Potential concerns with water quality include scaling from precipitation of barium sulfate and calcium sulfate; high concentrations of chlorides, which could increase the need for friction reducers; very high or low pH (e.g., water from mines); high concentrations of iron (water from quarries or mines) which could potentially plug fractures; microbes that can accelerate corrosion, scaling or other gas production; and high concentrations of sulfur (e.g. water from flue gas desulfurization impoundments), which could contaminate natural gas. In addition, water sources of variable quality could present difficulties.

Permittability – Applicable permits and approvals would need to be identified and assessed as to feasibility and schedule for obtaining approvals, conditions and limitations on approval that could impact the activity or require mitigation, and initial and ongoing fees and charges. Preliminary discussions with regulating authorities would be prudent to identify fatal flaws or obstacles.

Disposal – Proper disposal of flowback from hydraulic fracturing will be necessary, or appropriate treatment for re-use provided. Utilizing an alternate source with sub-standard quality water could add to treatment and disposal costs.

Cost – Sources that have a higher associated cost to acquire, treat, transport, permit, access or dispose, typically will be less desirable.

5.7.1 Delivery of Source Water to the Well Pad

Water could be delivered by truck or pipeline directly from the source to the well pad, or could be delivered by trucks or pipeline from centralized water storage or staging facilities consisting of tanks or engineered impoundments. Photo 5.21 shows a fresh water pipeline in Bradford County, Pennsylvania, to move fresh water from an impoundment to a well pad.

At the well pad, water is typically stored in 500-barrel steel tanks. These mobile storage tanks provide temporary storage of fresh water, and preclude the need for installation of centralized impoundments. They are double-walled, wheeled tanks with sealed entry and fill ports on top and heavy-duty drain valves with locking mechanisms at the base. These tanks are similar in construction to the ones used to temporarily store flowback water; see Photo 5.7.

Potential environmental impacts related to water transportation, including the number and duration of truck trips for moving both fluid and temporary storage tanks, will be addressed in Chapter 6. Mitigation measures are described in Chapter 7.

5.7.2 Use of Centralized Impoundments for Fresh Water Storage

Operators have indicated that centralized water storage impoundments will likely be utilized as part of a water management plan. Such facilities would allow the operators to withdraw water from surface water bodies during periods of high flow and store the water for use in future hydraulic fracturing activities, thus avoiding or reducing the need to withdraw water during lower-flow periods when the potential for negative impacts to aquatic environments and municipal drinking water suppliers is greater.

The proposed engineered impoundments would likely be constructed from compacted earth excavated from the impoundment site and then compressed to form embankments around the excavated area. Typically, such impoundments would then be lined to minimize the loss of water due to infiltration. See Section 8.2.2.2 for a description of the Department's existing regulatory program related to construction, operation and maintenance of such impoundments.

It is likely that an impoundment would service well pads within a radius of up to four miles, and that impoundment volume could be several million gallons with surface acreage of up to five acres. The siting and sizing of such impoundments would be affected by factors such as terrain, environmental conditions, natural barriers, surrounding land use and proximity to nearby development, particularly residential development, as well as by the operators' lease positions. It is not anticipated that a single centralized impoundment would service wells from more than one well operator.

Photo 5.22 depicts a centralized freshwater impoundment and its construction.

Photos 5.19 a & b Fortuna SRBC-approved Chemung River water withdrawal facility, Towanda PA. Source:

Photo 5.20 Fresh water supply pond. Black pipe in pond is a float to keep suction away from pond bottom liner. Ponds are completely enclosed by wire fence. Source: NYS DEC 2009.

Photo 5.21 Water pipeline from Fortuna central freshwater impoundments, Troy PA. Source: NYS DEC 2009.

Photo 5.22 Construction of freshwater impoundment in Upshur Co. WV. Source: Chesapeake Energy

5.8 Hydraulic Fracturing Design

Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected. In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures.[64] After the procedure is actually performed, the data gathered can be used to optimize future treatments.[65] Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging.[66,67] ICF International, under contract to NYSERDA to provide research assistance for this document, observed that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models.[68] Comparison of production pressure and flow-rate analysis to pre-fracture modeling is a more common method for evaluating the results of a hydraulic fracturing procedure.[69]

The objective in any hydraulic fracturing procedure is to limit fractures to the target formation. Excessive fracturing is undesirable from a cost standpoint because of the expense associated with unnecessary use of time and materials.[70] Economics would also dictate limiting the use of water, additives and proppants, as well as the need for fluid storage and handling equipment, to what is needed to treat the target formation.[71] In addition, if adjacent rock formations contain water, then fracturing into them would bring water into the reservoir formation and the well. This could

---

[64] GWPC, April 2009, p. 57.

[65] GWPC, April 2009, p. 57.

[66] GWPC, April 2009, p. 57.

[67] ICF, 2009, pp. 5-6.

[68] ICF, 2009, p.6.

[69] ICF, 2009, pp. 6-8.

[70] GWPC, April 2009, p. 58.

[71] ICF, 2009, p. 14.

result in added costs to handle production brine, or could result in loss of economic hydrocarbon production from the well.[72]

5.8.1 Fracture Development

ICF reviewed how hydraulic fracturing is affected by the rock's natural compressive stresses.[73] The dimensions of a solid material are controlled by major, intermediate and minor principal stresses within the material. In rock layers in their natural setting, these stresses are vertical and horizontal. Vertical stress increases with the thickness of overlying rock and exerts pressure on a rock formation to compress it vertically and expand it laterally. However, because rock layers are nearly infinite in horizontal extent relative to their thickness, lateral expansion is constrained by the pressure of the horizontally adjacent rock mass.[74]

Rock stresses may decrease over geologic time as a result of erosion acting to decrease vertical rock thickness. Horizontal stress decreases due to erosion more slowly than vertical stress, so rock layers that are closer to the surface have a higher ratio of horizontal stress to vertical stress.[75]

Fractures form perpendicular to the direction of least stress. If the minor principal stress is horizontal, fractures will be vertical. The vertical fractures would then propagate horizontally in the direction of the major and intermediate principal stresses.[76]

ICF notes that the initial stress field created during deposition and uniform erosion may become more complex as a result of geologic processes such as non-uniform erosion, folding and uplift. These processes result in topographic features that create differential stresses, which tend to die out at depths approximating the scale of the topographic features.[77] ICF – citing PTTC, 2006 – concludes that: "In the Appalachian Basin, the stress state would be expected to lead to

---

[72] GWPC, April 2009, p. 58.

[73] ICF, 2009, pp. 14-15.

[74] ICF, 2009, pp. 14-15.

[75] ICF, 2009, pp. 14-15.

[76] ICF, 2009, pp. 14-15.

[77] ICF, 2009, pp. 14-15.

predominantly vertical fractures below about 2500 feet, with a tendency towards horizontal fractures at shallower depths."[78]

5.8.2 Methods for Limiting Fracture Growth

ICF reports that, despite ongoing laboratory and field experimentation, the mechanisms that limit vertical fracture growth are not completely understood.[79] Pre-treatment modeling, as discussed above, is one tool for designing fracture treatments based on projected fracture behavior. Other control techniques identified by ICF include:[80]

- Use of a friction reducer, which helps to limit fracture height by reducing pumping loss within fractures, thereby maintaining higher fluid pressure at the fracture tip;
- Measuring fracture growth in real time by microseismic analysis, allowing the fracturing process to be stopped upon achieving the desired fracturing extent; and
- Reducing the length of wellbore fractured in each stage of the procedure, thereby focusing the applied pressure and proppant placement, and allowing for modifications to the procedure in subsequent stages based on monitoring the results of each stage.

5.8.3 Hydraulic Fracturing Design – Summary

ICF provided the following summary of the current state of hydraulic fracturing design to contain induced fractures in the target formation:

> Hydraulic fracturing analysis, design, and field practices have advanced dramatically in the last quarter century. Materials and techniques are constantly evolving to increase the efficiency of the fracturing process and increase reservoir production. Analytical techniques to predict fracture development, although still imperfect, provide better estimates of the fracturing results. Perhaps most significantly, fracture monitoring techniques are now available that provide confirmation of the extent of fracturing, allowing refinement of the procedures for subsequent stimulation activities to confine the fractures to the desired production zone.[81]

Photo 5.23 shows personnel monitoring a hydraulic fracturing procedure.

---

[78] ICF, 2009, pp. 14-15.

[79] ICF, 2009, p. 16.

[80] ICF, 2009, p. 17.

[81] ICF, 2009, p. 19.

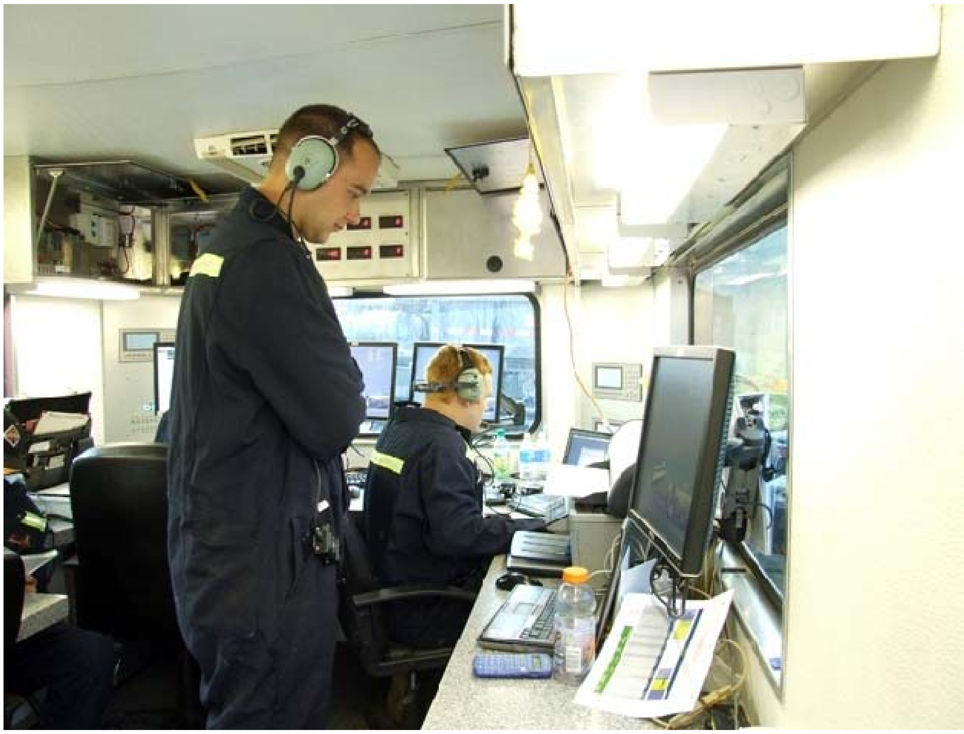


Photo 5.23 - Personnel monitoring a hydraulic fracturing procedure. Source: Fortuna Energy.

5.9 Hydraulic Fracturing Procedure

The fracturing procedure involves the controlled use of water and chemical additives, pumped under pressure into the cased and cemented wellbore. Composition, purpose, transportation, storage and handling of additives are addressed in previous sections of this document. Water and fluid management, including source, transportation, storage and disposition, are also discussed elsewhere in this document. Potential impacts, mitigation measures and the permit process are addressed in Chapters 6, 7, and 8. The discussion in this section describes only the specific physical procedure of high-volume hydraulic fracturing. Except where other references are specifically noted, operational details are derived from permit applications on file with the Department's Division of Mineral Resources (DMN) and responses to the Department's information requests provided by several operators and service companies about their planned operations in New York.

Hydraulic fracturing occurs after the well is cased and cemented to protect fresh water zones and isolate the target hydrocarbon-bearing zone, and after the drilling rig and its associated equipment have been removed. There will typically be at least three strings of cemented casing in the well during fracturing operations. The outer string (i.e., surface casing) extends below fresh ground water and would have been cemented to the surface before the well was drilled deeper. The intermediate casing string, also called protective string, is installed between the surface and production strings. The inner string (i.e., production casing) typically extends from the ground surface to the toe of the horizontal well. Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing strings. The inner production casing is the only casing string that will experience the high pressures associated with the fracturing treatment.[82] Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.

The last steps prior to fracturing are installation of a wellhead (referred to as a “frac tree”) that is designed and pressure-rated specifically for the fracturing operation, and pressure testing of the hydraulic fracturing system. Photo 5.24 depicts a frac tree that is pressure-rated for 10,000 psi. Before perforating the casing and pumping fracturing fluid into the well, the operator pumps fresh water, brine or drilling mud to pressure test the production casing, frac tree and associated lines. Test pumping is performed to at least the maximum anticipated treatment pressure, which is maintained for a period of time while the operator monitors pressure gauges. The purpose of this test is to verify, prior to pumping fracturing fluid, that the casing, frac tree and associated lines will successfully hold pressure and contain the treatment. The test pressure may exceed the maximum anticipated treatment pressure, but must remain below the working pressure of the lowest rated component of the hydraulic fracturing system, including the production casing.

Flowback equipment, including pipes, manifolds, a gas-water separator and tanks are connected to the frac tree and this portion of the flowback system is pressure tested prior to flowing the well.

---

[82] For more details on wellbore casing and cement: see Appendix 8 for current casing and cementing practices required for all wells in New York, Appendix 9 for additional permit conditions for wells drilled within the mapped areas of primary and principal aquifers, and Chapter 7 and Appendix 10 for proposed new permit conditions to address high-volume hydraulic fracturing.

Photo 5.24 - Three Fortuna Energy wells being prepared for hydraulic fracturing, with 10,000 psi well head and goat head attached to lines. Troy PA. Source: New York State Department of Environmental Conservation 2009

The hydraulic fracturing process itself is conducted in stages by successively isolating, perforating and fracturing portions of the horizontal wellbore starting with the far end, or toe. Reasons for conducting the operation in stages are to maintain sufficient pressure to fracture the entire length of the wellbore,[83] to achieve better control of fracture placement and to allow changes from stage to stage to accommodate varying geological conditions along the wellbore if necessary.[84] The length of wellbore treated in each stage will vary based on site-specific geology and the characteristics of the well itself, but may typically be 300 to 500 feet. In that case, the multi-stage fracturing operation for a 4,000-foot lateral would consist of eight to 13 fracturing stages. Each stage may require 300,000 to 600,000 gallons of water, so that the entire multi-stage fracturing operation for a single well would require 2.4 million to 7.8 million gallons

---

[83] GPWC, April 2009, p. 58.

[84] GPWC, April 2009, p. 58.

of water.[85] More or less water may be used depending on local conditions, evolution in fracturing technology, or other factors which influence the operator's and service company's decisions.

The entire multi-stage fracturing operation for a single horizontal well typically takes two to five days, but may take longer for longer lateral wellbores, for many-stage jobs or if unexpected delays occur. Not all of this time is spent actually pumping fluid under pressure, as intervals are required between stages for preparing the hole and equipment for the next stage. Pumping rate may be as high as 1,260 to 3,000 gallons per minute (gpm).[86,87] At these rates, all the stages in the largest volume fracturing job described in the previous paragraph would require between approximately 40 and 100 hours of intermittent pumping during a 2- to 5-day period. Pumping rates may vary from job-to-job and some operators have reported pump rates in excess of 3,000 gpm and hydraulic fracturing at these higher rates could shorten the overall time spent pumping.

The time spent pumping is the only time, except for when the well is shut-in, that wellbore pressure exceeds pressure in the surrounding formation. Therefore, the hours spent pumping are the only time that fluid in fractures and in the rocks surrounding the fractures would move away from the wellbore instead of towards it. ICF International, under contract to NYSERDA, estimated the maximum rate of seepage in strata lying above the target Marcellus zone, assuming hypothetically that the entire bedrock column between the Marcellus and a fresh groundwater aquifer is hydraulically connected. Under most conditions evaluated by ICF, the seepage rate would be substantially less than 10 feet per day, or 5 inches per hour of pumping time.[88] More information about ICF's analysis is in Chapter 6 and in Appendix 11.

Within each fracturing stage is a series of sub-stages, or steps.[89, 90] The first step is typically an acid treatment, which may also involve corrosion inhibitors and iron controls. Acid cleans the

---

[85] Applications on file with the Department propose volumes on the lower end of this range. The higher end of the range is based on GWPC (April 2009), pp. 58-59, where an example of a single-stage Marcellus fracturing treatment using 578,000 gallons of fluid is presented. Stage lengths used in the above calculation (300 – 500 feet) were provided by Fortuna Energy and Chesapeake Energy in presentations to Department staff during field tours of operations in the northern tier of Pennsylvania.

[86] ICF Task 1, 2009, p. 3.

[87] GPWC, April 2009, p. 59.

[88] ICF Task 1, 2009, pp. 27-28.

[89] URS, 2009, pp. 2-12.

near-wellbore area accessed through the perforated casing and cement, while the other additives that may be used in this phase reduce rust formation and prevent precipitation of metal oxides that could plug the shale. The acid treatment is followed by the “slickwater pad,” comprised primarily of water and a friction-reducing agent which helps optimize the pumping rate. Fractures form during this stage when the fluid pressure exceeds the minimum normal stress in the rock mass plus whatever minimal tensile stress exists.[91] The fractures are filled with fluid, and as the fracture width grows, more fluid must be pumped at the same or greater pressure exerted to maintain and propagate the fractures.[92] As proppant is added, other additives such as a gelling agent and crosslinker may be used to increase viscosity and improve the fluid’s capacity to carry proppant. Fine-grained proppant is added first, and carried deepest into the newly induced fractures, followed by coarser-grained proppant. Breakers may be used to reduce the fluid viscosity and help release the proppant into the fractures. Biocides may also be added to inhibit the growth of bacteria that could interfere with the process and produce hydrogen sulfide. Clay stabilizers may be used to prevent swelling and migration of formation clays. The final step in the hydraulic fracturing process is a freshwater or brine flush to clean out the wellbore and equipment. After hydraulic fracturing is complete, the stage plugs are removed through a milling process routinely accomplished by a relatively small workover rig, snubbing unit and/or coiled tubing unit. A snubbing unit or coiled tubing unit may be required if the well is not dead or if pressure is anticipated after milling through the plugs. Stage plugs may be removed before or after initial flowback depending upon the type of plug used.

Photos 5.25 and 5.26 depict the same wellsite during and after hydraulic fracturing operations, with Photo 5.25 labeled to identify the equipment that is present onsite. Photo 5.27 is a labeled close-up of a wellhead and equipment at the site during hydraulic fracturing operations.

---

[90] GWPC, April 2009, pp. 58-60.

[91] ICF Task 1, 2009. p. 16.

[92] ICF Task 1, 2009. p. 16.


16
14
1
4
2
7
12
8
15
13
9
3
11
10
4
5
6
17
18
19

Photo 5.25 (Above) Hydraulic Fracturing Operation

These photos show a hydraulic fracturing operation at a Fortuna Energy multi-well site in Troy PA. At the time the photos were taken, preparations for fracturing were underway but fracturing had not yet occurred for any of the wells.

Hydraulic Fracturing Operation Equipment

1. Well head and frac tree with 'Goat Head' (See Figure 5.27 for more detail)
2. Flow line (for flowback & testing)
3. Sand separator for flowback
4. Flowback tanks
5. Line heaters
6. Flare stack
7. Pump trucks
8. Sand hogs
9. Sand trucks
10. Acid trucks
11. Frac additive trucks
12. Blender
13. Frac control and monitoring center
14. Fresh water impoundment
15. Fresh water supply pipeline
16. Extra tanks

Production equipment

17. Line heaters
18. Separator-meter skid
19. Production manifold

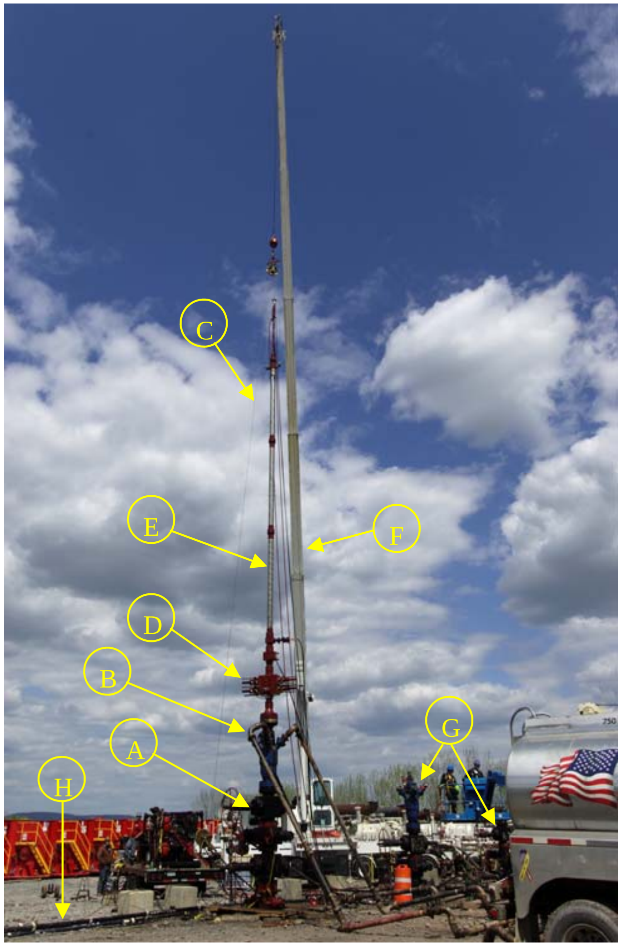


Photo 5.27. Wellhead and Frac Equipment
A. Well head and frac tree (valves)
B. Goat Head (for frac flow connections)
C. Wireline (used to convey equipment into wellbore)
D. Wireline Blow Out Preventer
E. Wireline lubricator
F. Crane to support wireline equipment
G. Additional wells
H. Flow line (for flowback & testing)

Photo 5.26 Fortuna multi-well pad after hydraulic fracturing of three wells and removal of most hydraulic fracturing equipment. Production equipment for wells on right side of photo. Source: Fortuna Energy, July, 2009.

5.10 Re-fracturing

Developers may decide to re-fracture a well to extend its economic life whenever the production rate declines significantly below past production rates or below the estimated reservoir potential.[93] According to ICF International, fractured Barnett Shale wells generally would benefit from re-fracturing within five years of completion, but the time between fracture stimulations can be less than one year or greater than ten years.[94] However, Marcellus operators with whom the Department has discussed this question have stated their expectation that re-fracturing will be a rare event.

It is too early in the development of shale reservoirs in New York to predict the frequency with which re-fracturing of horizontal wells, using the slickwater method, may occur. ICF provided some general information on the topic of re-fracturing.

Wells may be re-fractured multiple times, may be fractured along sections of the wellbore that were not previously fractured, and may be subject to variations from the original fracturing technique.[95] The Department notes that while one stated reason to re-fracture may be to treat sections of the wellbore that were not previously fractured, this scenario does not seem applicable to Marcellus Shale development. Current practice in the Marcellus Shale in the northern tier of Pennsylvania is to treat the entire lateral wellbore, in stages, during the initial procedure.

Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary.[96] Re-fracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.[97] Changes in formation stresses due to the

---

[93] ICF Task 1, 2009, p. 18.

[94] ICF Task 1, 2009, p. 18.

[95] ICF Task 1, 2009, p. 17.

[96] ICF Task 1, 2009, p. 17.

[97] ICF Task 1, 2009, p. 17.

reduction in pressure from production can sometimes cause new fractures to propagate at a different orientation than the original fractures, further extending the fracture zone.[98]

Factors that influence the decision to re-fracture include past well production rates, experience with other wells in the same formation, the costs of re-fracturing, and the current price for gas.[99] Factors in addition to the costs of re-fracturing and the market price for gas that determine cost-effectiveness include the characteristics of the geologic formation and the time value of money.[100]

Regardless of how often it occurs, if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure. The rate of subsurface fluid movement during pumping operations would be the same as discussed above. It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore. Therefore, total fluid movement away from the wellbore as a result of repeated fracture treatments would be less than the sum of the distance moved during each fracture treatment.

5.11 Fluid Return

After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses. The well is "cleaned up" by allowing water and excess proppant to flow up through the wellbore to the surface. Both the process and the returned water are commonly referred to as “flowback.”

5.11.1 Flowback Water Recovery

Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9. This volume is generally recovered within two to eight weeks, then the well’s water production rate sharply

---

[98] ICF Task 1, 2009, pp. 17-18.

[99] ICF Task 1, 2009, p. 18.

[100] ICF Task 1, 2009, p. 18.

declines and levels off at a few barrels per day for the remainder of its producing life. URS Corporation reported that limited time-series data indicates that approximately 60 percent of the total flowback occurs in the first four days after fracturing.[101]

5.11.2 Flowback Water Handling at the Wellsite

As discussed throughout this document, the Department will require water-tight tanks for on-site (i.e., well pad) handling of flowback water for wells covered by the SGEIS.

5.11.3 Flowback Water Characteristics

The 1992 GEIS identified high TDS, chlorides, surfactants, gelling agents and metals as the components of greatest concern in spent gel and foam fracturing fluids (i.e., flowback). Slickwater fracturing fluids proposed for Marcellus well stimulation may contain other additives such as corrosion inhibitors, friction reducers and microbiocides, in addition to the contaminants of concern identified in the GEIS. Most fracturing fluid additives used in a well can be expected in the flowback water, although some are expected to be consumed in the well (e.g., strong acids) or react during the fracturing process to form different products (e.g., polymer precursors).

The following description of flowback water characteristics was provided by URS Corporation,[102] under contract to NYSERDA. This discussion is based on a limited number of analyses from out-of-state operations, without corresponding complete compositional information on the fracturing additives that were used at the source wells. The Department did not direct or oversee sample collection or analysis efforts. Most fracturing fluid components are not included as analytes in standard chemical scans of flowback samples that were provided to the Department, so little information is available to document whether and at what concentrations most fracturing chemicals occur in flowback water. Because of the limited availability at this time of flowback water quality data, conservative and strict mitigation measures regarding flowback water handling are proposed in Chapter 7, and additional data will be required for alternative proposals.

---

[101] URS, 2009, p. 3-2.

[102] URS, 2009, p. 3-2 & 2011, p. 3-2.

Flowback fluids include the fracturing fluids pumped into the well, which consists of water and additives discussed in Section 5.4; any new compounds that may have formed due to reactions between additives; and substances mobilized from within the shale formation due to the fracturing operation. Some portion of the proppant may return to the surface with flowback, but operators strive to minimize proppant return: the ultimate goal of hydraulic fracturing is to convey and deposit the proppant within fractures in the shale to maximize gas flow.

Marcellus Shale is of marine origin and, therefore, contains high levels of salt. This is further evidenced by analytical results of flowback provided to the Department by well operators and service companies from operations based in Pennsylvania. The results vary in level of detail. Some companies provided analytical results for one day for several wells, while other companies provided several analytical results for different days of the same well (i.e. time-series).

Typical classes of parameters present in flowback fluid are:

- Dissolved solids (chlorides, sulfates, and calcium);
- Metals (calcium, magnesium, barium, strontium);
- Suspended solids;
- Mineral scales (calcium carbonate and barium sulfate);
- Bacteria - acid producing bacteria and sulfate reducing bacteria;
- Friction reducers;
- Iron solids (iron oxide and iron sulfide);
- Dispersed clay fines, colloids & silts; and
- Acid gases (carbon dioxide, hydrogen sulfide).

A list of parameters detected in a limited set of analytical results is provided in Table 5.9. Typical concentrations of parameters other than radionuclides, based on limited data from Pennsylvania and West Virginia, are provided in Table 5.10 and Table 5.11. Flowback parameters were organized by CAS number, whenever available. Radionuclides are separately discussed and tabulated in Section 5.11.3.3.

Table 5.9 - Parameters present in a limited set of flowback analytical results[103] (Updated July 2011)

CAS Number	Parameters Detected in Flowback from PA and WV Operations
00087-61-6	1,2,3-Trichlorobenzene
00095-63-6	1,2,4-Trimethylbenzene
00108-67-8	1,3,5-Trimethylbenzene
00105-67-9	2,4-Dimethylphenol
00087-65-0	2,6-Dichlorophenol
00078-93-3	2-Butanone / Methyl ethyl ketone
00091-57-6	2-Methylnaphthalene
00095-48-7	2-Methylphenol
109-06-8	2-Picoline (2-methyl pyridine)
00067-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol
00108-39-4	3-Methylphenol
00106-44-5	4-Methylphenol
00072-55-9	4,4 DDE
00057-97-6	7,12-Dimethylbenz(a)anthracene
00064-19-7	Acetic acid
00067-64-1	Acetone
00098-86-2	Acetophenone
00107-13-1	Acrylonitrile
00309-00-2	Aldrin
07439-90-5	Aluminum
07440-36-0	Antimony
07664-41-7	Aqueous ammonia
12672-29-6	Aroclor 1248
07440-38-2	Arsenic
07440-39-3	Barium
00071-43-2	Benzene
00050-32-8	Benzo(a)pyrene
00205-99-2	Benzo(b)fluoranthene
191-24-2	Benzo(ghi)perylene
00207-08-9	Benzo(k)fluoranthene
00100-51-6	Benzyl alcohol
07440-41-7	Beryllium
00111-44-4	Bis(2-Chloroethyl) ether
00117-81-7	Bis(2-ethylhexyl)phthalate / Di (2-ethylhexyl) phthalate
07440-42-8	Boron
24959-67-9	Bromide
00075-25-2	Bromoform
07440-43-9	Cadmium
07440-70-2	Calcium
00124-38-9	Carbon Dioxide
00075-15-0	Carbondisulfide
00124-48-1	Chlorodibromomethane
00067-66-3	Chloroform
07440-47-3	Chromium

---

[103] This table contains information compiled from flowback analyses submitted to the Department by well operators as well as flowback information from the Marcellus Shale Coalition Study.

CAS Number	Parameters Detected in Flowback from PA and WV Operations
07440-48-4	Cobalt
07440-50-8	Copper
00057-12-5	Cyanide
00319-85-7	Cyclohexane (beta BHC)
00058-89-9	Cyclohexane (gamma BHC)
00055-70-3	Dibenz(a,h)anthracene
00075-27-4	Dichlorobromomethane
00084-74-2	Di-n-butyl phthalate
00122-39-4	Diphenylamine
00959-98-8	Endosulfan I
33213-65-9	Endosulfan II
07421-93-4	Endrin aldehyde
00107-21-1	Ethane-1,2-diol / Ethylene Glycol
00100-41-4	Ethyl Benzene
00206-44-0	Fluoranthene
00086-73-7	Fluorene
16984-48-8	Fluoride
00076-44-8	Heptachlor
01024-57-3	Heptachlor epoxide
00193-39-5	Indeno(1,2,3-cd)pyrene
07439-89-6	Iron
00098-82-8	Isopropylbenzene (cumene)
07439-92-1	Lead
07439-93-2	Lithium
07439-95-4	Magnesium
07439-96-5	Manganese
07439-97-6	Mercury
00067-56-1	Methanol
00074-83-9	Methyl Bromide
00074-87-3	Methyl Chloride
07439-98-7	Molybdenum
00091-20-3	Naphthalene
07440-02-0	Nickel
00086-30-6	N-Nitrosodiphenylamine
00085-01-8	Phenanthrene
00108-95-2	Phenol
57723-14-0	Phosphorus
07440-09-7	Potassium
00057-55-6	Propylene glycol
00110-86-1	Pyridine
00094-59-7	Safrole
07782-49-2	Selenium
07440-22-4	Silver
07440-23-5	Sodium
07440-24-6	Strontium
14808-79-8	Sulfate
14265-45-3	Sulfite
00127-18-4	Tetrachloroethylene
07440-28-0	Thallium

CAS Number	Parameters Detected in Flowback from PA and WV Operations
07440-32-6	Titanium
00108-88-3	Toluene
07440-62-2	Vanadium
07440-66-6	Zinc
	2-Picoline
	Alkalinity
	Alkalinity, Carbonate, as CaCO3
	Alpha radiation
	Aluminum, Dissolved
	Barium Strontium P.S.
	Barium, Dissolved
	Beta radiation
	Bicarbonates
	Biochemical Oxygen Demand
	Cadmium, Dissolved
	Calcium, Dissolved
	Cesium 137
	Chemical Oxygen Demand
	Chloride
	Chromium (VI)
	Chromium (VI), dissolved
	Chromium, (III)
	Chromium, Dissolved
	Cobalt, dissolved
	Coliform
	Color
	Conductivity
	Hardness
	Heterotrophic plate count
	Iron, Dissolved
	Lithium, Dissolved
	Magnesium, Dissolved
	Manganese, Dissolved
	Nickel, Dissolved
	Nitrate, as N
	Nitrogen, Total as N
	Oil and Grease
	Petroleum hydrocarbons
	pH
	Phenols
	Potassium, Dissolved
	Radium
	Radium 226
	Radium 228
	Salt
	Scale Inhibitor
	Selenium, Dissolved
	Silver, Dissolved
	Sodium, Dissolved

CAS Number	Parameters Detected in Flowback from PA and WV Operations
	Strontium, Dissolved
	Sulfide
	Surfactants
	Total Alkalinity
	Total Dissolved Solids
	Total Kjeldahl Nitrogen
	Total Organic Carbon
	Total Suspended Solids
	Volatile Acids
	Xylenes
	Zinc, Dissolved
	Zirconium

Parameters listed in Table 5.9, Table 5.10 and Table 5.11 are based on analytical results of flowback from operations in Pennsylvania or West Virginia. All information is for operations in the Marcellus Shale, however it is not from a single comprehensive study. The data are based on analyses performed by different laboratories; most operators provided only one sample/analysis per well, a few operators provided time-series samples for a single well; the different samples were analyzed for various parameters with some overlap of parameters. Even though the data are not strictly comparable, they provide valuable insight on the likely composition of flowback at New York operations.

Table 5.10 - Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[104,105] (Revised July 2011)

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
00067-64-1	Acetone	3	1	681	681	681	μg/L
	Acidity, Total	4	4	101	240	874	mg/L
	Alkalinity [106]	155	155	0	153	384	mg/L
	Alkalinity, Carbonate, as $CaCO_3$	164	163	0	9485	48336	mg/L
	Total Alkalinity	5	5	28	91	94	mg/L
07439-90-5	Aluminum	43	12	0.02	0.07	1.2	mg/L
	Aluminum, Dissolved	22	1	1.37	1.37	1.37	mg/L
07440-36-0	Antimony	34	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	48	45	11.3	44.8	382	mg/L
07440-38-2	Arsenic	43	7	0.015	0.09	0.123	mg/L
07440-39-3	Barium	48	47	0.553	1450	15700	mg/L
	Barium, Dissolved	22	22	0.313	212	19200	mg/L
00071-43-2	Benzene	35	14	15.7	479.5	1950	μg/L
07440-41-7	Beryllium	43	1	422	422	422	mg/L
	Bicarbonates	150	150	0	183	1708	mg/L
	Biochemical Oxygen Demand	38	37	3	200	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	20	2	10.3	15.9	21.5	μg/L
07440-42-8	Boron	23	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	15	15	11.3	607	3070	mg/L
00075-25-2	Bromoform	26	2	34.8	36.65	38.5	μg/L
07440-43-9	Cadmium	43	6	0.007	0.025	1.2	mg/L
	Cadmium, Dissolved	22	2	0.017	0.026	0.035	mg/L
07440-70-2	Calcium	187	186	29.9	4241	123000	mg/L
	Calcium, Dissolved	3	3	2360	22300	31500	mg/L
	Cesium 137 [107]	16	2	9.9	10.2	10.5	pCi/L
	Chemical Oxygen Demand	38	38	223	5645	33300	mg/L
	Chloride	193	193	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	26	2	3.28	3.67	4.06	μg/L
07440-47-3	Chromium	43	9	0.009	0.082	760	mg/L
	Chromium (VI), dissolved	19	10	0.0126	0.539	7.81	mg/L

---

[104] Table 5.9 was provided by URS Corporation (based on data submitted to the Department) with the following note: Information presented is based on limited data from Pennsylvania and West Virginia. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. In addition, the raw data for these tables came from several sources, with likely varying degrees of reliability. Also, the analytical methods used were not all the same for given parameters. Sometimes laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days soon after the well is fractured. This data does not control for any of these variables. Additionally, it should be noted that several of these compounds could be traced back to potential laboratory contamination. Further comparisons of analytical results with those results from associated laboratory method blanks may be required to further assess the extent of actual concentrations found in field samples versus elevated concentrations found in field samples due to blank contamination.

[105] This table does not include results from the Marcellus Shale Coalition Study.

[106] Different data sources reported alkalinity in different and valid forms. Total alkalinity reported here is smaller than carbonate alkalinity because the data came from different sources.

[107] Regulated under beta particles [19].

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	Chromium, Dissolved	22	2	0.058	0.075	0.092	mg/L
07440-48-4	Cobalt	30	6	0.03	0.3975	0.62	mg/L
	Cobalt, dissolved	19	1	0.489	0.489	0.489	mg/L
	Coliform, Total	5	2	1	42	83	Col/100mL
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	43	8	0.01	0.0245	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	µg/L
00100-41-4	Ethyl Benzene	38	14	3.3	53.6	164	µg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
	Heterotrophic plate count	5	3	25	50	565	CFU/mL
07439-89-6	Iron	193	168	0	29.2	810	mg/L
	Iron, Dissolved	34	26	6.75	63.25	196	mg/L
07439-92-1	Lead	43	6	0.008	0.035	27.4	mg/L
	Lithium	13	13	34.4	90.4	297	mg/L
	Lithium, Dissolved	4	4	24.5	61.35	144	mg/L
07439-95-4	Magnesium	193	180	9	177	3190	mg/L
	Magnesium, Dissolved	3	3	218	2170	3160	mg/L
	Mg as CaCO3	145	145	36	547	8208	mg/L
07439-96-5	Manganese	43	29	0.15	1.89	97.6	mg/L
	Manganese, Dissolved	22	12	0.401	2.975	18	mg/L
07439-97-6	Mercury	30	2	0.0006	0.295	0.59	mg/L
00074-83-9	Methyl Bromide	26	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	26	1	15.6	15.6	15.6	µg/L
07439-98-7	Molybdenum	34	12	0.16	0.44	1.08	mg/L
00091-20-3	Naphthalene	23	1	11.3	11.3	11.3	µg/L
07440-02-0	Nickel	43	15	0.01	0.03	0.137	mg/L
	Nickel, Dissolved	22	2	0.03	0.0715	0.113	mg/L
	Nitrate, as N	1	1	0.025	0.025	0.025	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	39	9	5	17	1470	mg/L
	Petroleum hydrocarbons	1	1	0.21	0.21	0.21	mg/L
	pH	191	191	0	6.6	8.58	S.U.
00108-95-2	Phenol	20	1	459	459	459	µg/L
	Phenols	35	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L
07440-09-7	Potassium	33	17	15.5	125	7810	mg/L
	Potassium, Dissolved	3	3	84.2	327	7080	mg/L
	Scale Inhibitor	145	145	315	744	1346	mg/L
07782-49-2	Selenium	34	1	0.058	0.058	0.058	mg/L
	Selenium, Dissolved	22	1	1.06	1.06	1.06	mg/L
07440-22-4	Silver	43	3	0.129	0.204	6.3	mg/L
	Silver, Dissolved	22	2	0.056	0.0825	0.109	mg/L
07440-23-5	Sodium	42	41	83.1	23500	96700	mg/L
	Sodium, Dissolved	3	3	9290	54800	77400	mg/L
07440-24-6	Strontium	36	36	0.501	1115	5841	mg/L
	Strontium, Dissolved	22	21	8.47	629	7290	mg/L
14808-79-8	Sulfate (as SO_4)	193	169	0	1	1270	mg/L
	Sulfide (as S)	8	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO_3)	3	3	2.56	64	64	mg/L
	Surfactants [108]	12	12	0.1	0.21	0.61	mg/L

---

[108] Regulated under foaming agents.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
00127-18-4	Tetrachloroethylene	26	1	5.01	5.01	5.01	μg/L
07440-28-0	Thallium	34	2	0.1	0.18	0.26	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	38	15	2.3	833	3190	μg/L
	Total Dissolved Solids	193	193	1530	63800	337000	mg/L
07440-62-2	Vanadium	24	1	40.4	40.4	40.4	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [109]	28	23	69.2	449	1080	mg/L
	Total Suspended Solids	43	43	16	129	2080	mg/L
	Xylenes	38	15	15.3	444	2670	μg/L
07440-66-6	Zinc	43	18	0.011	0.036	8570	mg/L
	Zinc, Dissolved	22	1	0.07	0.07	0.07	mg/L
	Fluid Density	145	145	8.39004	8.7	9.2	lb/gal
	Hardness by Calculation	170	170	203	11354	98000	mg $CaCO_3$/L
	Salt %	145	145	0.9	5.8	13.9	%
	Specific Conductivity	15	15	1030	110000	165000	pmhos/cm
	Specific Gravity	150	154	0	1.04	1.201	
	Temperature	31	31	0	15.3	32	°C
	Temperature	145	145	24.9	68	76.1	°F

Table 5.11 - Typical concentrations of flowback constituents based on limited samples from PA and WV, not regulated in NY[110](Revised July 2011)

Parameter Name	Total Number of Samples	Detects	Min	Median	Max	Units
Barium Strontium P.S.	145	145	17	1320	6400	mg/L
Carbon Dioxide	5	5	193	232	294	mg/L
Zirconium	19	1	0.054	0.054	0.054	mg/L

---

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

[110] Table 5-10.

Recognizing the dearth of comparable flowback information that existed at that time within the Marcellus Shale, the Marcellus Shale Coalition (MSC) facilitated a more rigorous study in 2009. The study:

- Gathered and analyzed flowback samples from 19 gas well sites (names A through S) in Pennsylvania or West Virginia;
- Took samples at different points in time, typically of the influent water stream, and flowback water streams 1, 5, 14, and 90 days after stimulating the well. In addition, the water supply and the fracturing fluid (referred to as Day 0) were also sampled at a few locations;
- Included both vertical and horizontal wells;
- All samples were collected by a single contractor;
- All analyses were performed by a single laboratory;
- Sought input from regulatory agencies in Pennsylvania and West Virginia; and
- Most samples were analyzed for conventional parameters, Metals, VOCs, Semi-Volatile Organic Compounds (SVOCs), Organochlorine Pesticides, Polychlorinated Biphenyls (PCBs), an Organophosphorus Pesticide, Alcohols, Glycols, and Acids. The specific parameters analyzed in the MSC report are listed by class as follows:
    - 29 conventional parameters (presented in Table 5.12);
    - 59 total or dissolved metals (presented in Table 5.13);
    - 70 VOCs (presented in Table 5.14);
    - 107 SVOCs (presented in Table 5.15);
    - 20 Organochlorine Pesticides (presented in Table 5.16);
    - 7 PCB Arochlors (presented in Table 5.17);
    - 1 Organophosphorus Pesticide (presented in Table 5.18);
    - 5 Alcohols (presented in Table 5.19);
    - 2 Glycols (presented in Table 5.20); and
    - 4 Acids (presented in Table 5.21).

Table 5.12 - Conventional Analytes In MSC Study (New July 2011)

Acidity	Nitrate as N	Total phosphorus
Amenable cyanide	Nitrate-nitrite	Total suspended solids
Ammonia nitrogen	Nitrite as N	Turbidity
Biochemical oxygen demand	Oil & grease (HEM)	Total cyanide
Bromide	Specific conductance	Total sulfide
Chemical oxygen demand (COD)	Sulfate	pH
Chloride	TOC	Total recoverable phenolics
Dissolved organic carbon	Total alkalinity	Sulfite
Fluoride	Total dissolved solids	MBAS (mol.wt 320)
Hardness, as $CaCO_3$	Total Kjeldahl nitrogen	

Table 5.13 - Total and Dissolved Metals Analyzed In MSC Study (New July 2011)

	Copper	Silver
Aluminum-dissolved	Copper-dissolved	Silver-dissolved
Antimony	Iron	Sodium
Antimony-dissolved	Iron-dissolved	Sodium-dissolved
Arsenic	Lead	Strontium
Arsenic-dissolved	Lead-dissolved	Strontium-dissolved
Barium	Lithium	Thallium
Barium-dissolved	Lithium-dissolved	Thallium-dissolved
Beryllium	Magnesium	Tin
Beryllium-dissolved	Magnesium-dissolved	Tin-dissolved
Boron	Manganese	Titanium
Boron-dissolved	Manganese-dissolved	Titanium-dissolved
Cadmium	Molybdenum	Trivalent chromium
Cadmium-dissolved	Molybdenum-dissolved	Zinc
Calcium	Nickel	Zinc-dissolved
Calcium-dissolved	Nickel-dissolved	Hexavalent chromium-dissolved
Chromium	Potassium	Hexavalent chromium
Chromium-dissolved	Potassium-dissolved	Mercury
Cobalt	Selenium	Mercury-dissolved
Cobalt-dissolved	Selenium-dissolved	

Table 5.14 - Volatile Organic Compounds Analyzed in MSC Study (New July 2011)

	2-Chloroethyl vinyl ether	Ethylbenzene
1,1,1-Trichloroethane	2-Hexanone	Isopropylbenzene
1,1,2,2-Tetrachloroethane	4-Chlorotoluene	Methyl tert-butyl ether (MTBE)
1,1,2-Trichloroethane	4-Methyl-2-pentanone (MIBK)	Methylene chloride
1,1-Dichloroethane	Acetone	Naphthalene
1,1-Dichloroethene	Acrolein	n-Butylbenzene
1,1-Dichloropropene	Acrylonitrile	n-Propylbenzene
1,2,3-Trichlorobenzene	Benzene	p-Isopropyltoluene
1,2,3-Trichloropropane	Benzyl chloride	sec-Butylbenzene
1,2,4-Trichlorobenzene	Bromobenzene	Styrene
1,2,4-Trimethylbenzene	Bromodichloromethane	tert-butyl acetate
1,2-Dibromo-3-chloropropane	Bromoform	tert-Butylbenzene
1,2-Dibromoethane (EDB)	Bromomethane	Tetrachloroethene
1,2-Dichlorobenzene	Carbon disulfide	tetrahydrofuran
1,2-Dichloroethane	Carbon tetrachloride	Toluene
1,2-Dichloropropane	Chlorobenzene	trans-1,2-Dichloroethene
1,3,5-Trimethylbenzene	Chloroethane	trans-1,3-Dichloropropene
1,3-Dichlorobenzene	Chloroform	Trichloroethene
1,3-Dichloropropane	Chloromethane	Trichlorofluoromethane
1,4-Dichlorobenzene	cis-1,2-Dichloroethene	Vinyl acetate
1,4-Dioxane	cis-1,3-Dichloropropene	Vinyl chloride
1-chloro-4-trifluoromethylbenzene	Dibromochloromethane	Xylenes (total)
2,2-Dichloropropane	Dibromomethane	
2-Butanone	Dichlorodifluoromethane	

Table 5.15 - Semi-Volatile Organics Analyzed in MSC Study (New July 2011)

1,2,4,5-Tetrachlorobenzene	7,12-Dimethylbenz(a)anthracene	Hexachlorocyclopentadiene
1,2-Diphenylhydrazine	Acenaphthene	Hexachloroethane
1,3-Dinitrobenzene	Acenaphthylene	Hexachloropropene
1,4-Naphthoquinone	Acetophenone	Indeno(1,2,3-cd)pyrene
1-Naphthylamine	Aniline	Isodrin
2,3,4,6-Tetrachlorophenol	Aramite	Isophorone
2,3,7,8-TCDD	Benzidine	Isosafrole
2,4,5-Trichlorophenol	Benzo(a)anthracene	Methyl methanesulfonate
2,4,6-Trichlorophenol	Benzo(a)pyrene	Nitrobenzene
2,4-Dimethylphenol	Benzo(b)fluoranthene	N-Nitrosodiethylamine
2,4-Dinitrophenol	Benzo(ghi)perylene	N-Nitrosodimethylamine
2,4-Dinitrotoluene	Benzo(k)fluoranthene	N-Nitrosodi-n-butylamine
2,6-Dichlorophenol	Benzyl alcohol	N-Nitrosodi-n-propylamine
2,6-Dinitrotoluene	bis(2-Chloroethoxy)methane	N-Nitrosodiphenylamine
2-Acetylaminofluorene	bis(2-Chloroethyl) ether	N-Nitrosomethylethylamine
2-Chloronaphthalene	bis(2-Chloroisopropyl) ether	N-Nitrosomorpholine
2-Chlorophenol	bis(2-Ethylhexyl) phthalate	N-Nitrosopiperidine
2-Methylnaphthalene	Butyl benzyl phthalate	N-Nitrosopyrrolidine
2-Methylphenol	Chlorobenzilate	O,O,O-Triethyl phosphorothioate
2-Naphthylamine	Chrysene	o-Toluidine
2-Nitroaniline	Diallate	Parathion
2-Nitrophenol	Dibenz(a,h)anthracene	p-Dimethylaminoazobenzene
2-Picoline	Dibenzofuran	Pentachlorobenzene
3,3'-Dichlorobenzidine	Diethyl phthalate	Pentachloroethane
3-Methylcholanthrene	Dimethoate	Pentachloronitrobenzene
3-Methylphenol & 4-Methylphenol	Dimethyl phthalate	Pentachlorophenol
3-Nitroaniline	Di-n-butyl phthalate	Phenanthrene
4,6-Dinitro-2-methylphenol	Di-n-octyl phthalate	Phenol
4-Aminobiphenyl	Dinoseb	Phorate
4-Bromophenyl phenyl ether	Diphenylamine	Pronamide
4-Chloro-3-methylphenol	Disulfoton	Pyrene
4-Chloroaniline	Ethyl methanesulfonate	Pyridine
4-Chlorophenyl phenyl ether	Fluoranthene	Safrole
4-Nitroaniline	Fluorene	Thionazin
4-Nitrophenol	Hexachlorobenzene	Tetraethyldithiopyrophosphate
5-Nitro-o-toluidine	Hexachlorobutadiene	

Table 5.16 - Organochlorine Pesticides Analyzed in MSC Study (New July 2011)

4,4'-DDD	delta-BHC	Endrin ketone
4,4'-DDE	Dieldrin	gamma-BHC (Lindane)
4,4'-DDT	Endosulfan I	Heptachlor
Aldrin	Endosulfan II	Heptachlor epoxide
alpha-BHC	Endosulfan sulfate	Methoxychlor
beta-BHC	Endrin	Toxaphene
Chlordane	Endrin aldehyde	

Table 5.17 - PCBs Analyzed in MSC Study (New July 2011)

Aroclor 1016	Aroclor 1242	Aroclor 1260
Aroclor 1221	Aroclor 1248	
Aroclor 1232	Aroclor 1254	

Table 5.18 - Organophosphorus Pesticides Analyzed in MSC Study (New July 2011)

Ethyl parathion

Table 5.19 - Alcohols Analyzed in MSC Study (New July 2011)

2-Propanol	Ethanol	n-Propanol
Butyl alcohol	Methanol	

Table 5.20 - Glycols Analyzed in MSC Study (New July 2011)

Ethylene glycol
Propylene glycol

Table 5.21 - Acids Analyzed in MSC Study (New July 2011)

Acetic acid	Propionic acid
Butyric acid	Volatile acids

Table 5.22 is a summary of parameter classes analyzed for (shown with a "•") at each well site. Table 5.23 is a summary of parameters detected at quantifiable levels. The check mark (√) indicates that several samples detected many parameters within a class. The MSC Study Report lists the following qualifiers associated with analytical results:

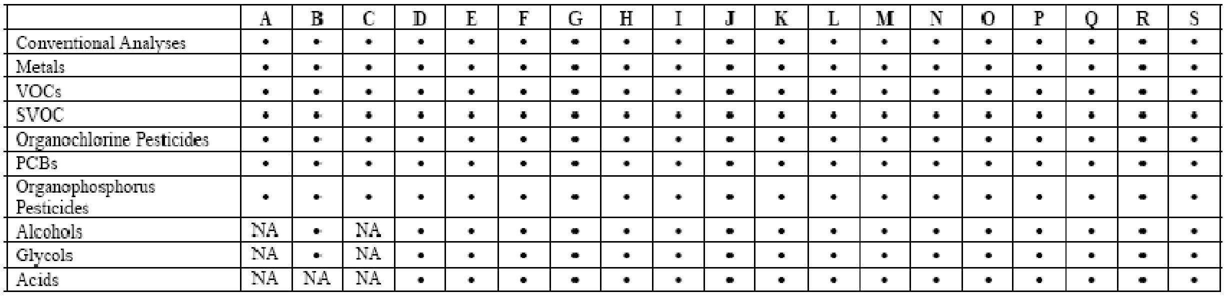
The sample was diluted (from 1X, which means no dilution, to up to 1000X) due to concentrations of analytes exceeding calibration ranges of the instrumentation or due to potential matrix effect. Laboratories use best judgment when analyzing samples at the lowest dilution factors allowable without causing potential damage to the instrumentation;

The analyte was detected in the associated lab method blank for the sample. Sample results would be flagged with a laboratory-generated single letter qualifier (i.e., “B”);

The estimated concentration of the analyte was detected between the method detection limit and the reporting limit. Sample results would be flagged with a laboratory-generated single letter qualifier (i.e., “J”). These results should be considered as estimated concentrations; and

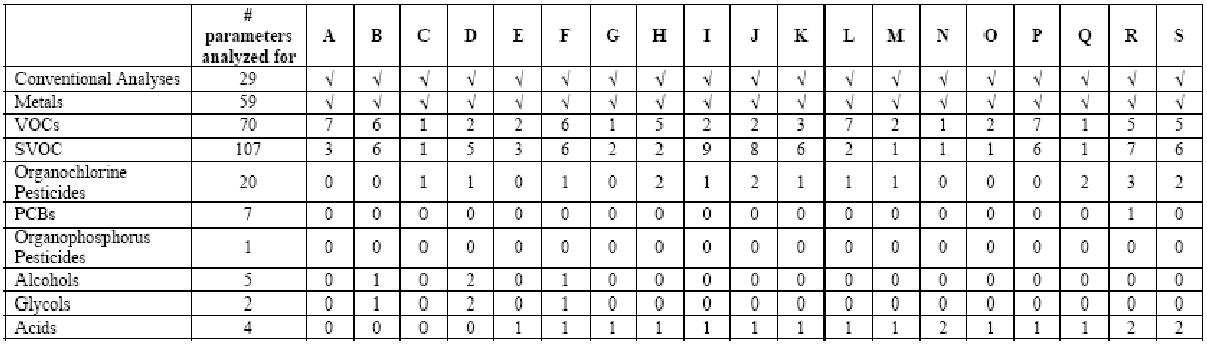
The observed value was less than the method detection limit. These results will be flagged with a “U.”

Table 5.22 - Parameter Classes Analyzed for in the MSC Study (New July 2011)



	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Conventional Analyses	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Metals	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
VOCs	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
SVOC	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Organochlorine Pesticides	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
PCBs	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Organophosphorus Pesticides	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Alcohols	NA	•	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Glycols	NA	•	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Acids	NA	NA	NA	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•

Table 5.23 - Parameter Classes Detected in Flowback Analyticals in MSC Study (New July 2011)



	# parameters analyzed for	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
Conventional Analyses	29	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Metals	59	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
VOCs	70	7	6	1	2	2	6	1	5	2	2	3	7	2	1	2	7	1	5	5
SVOC	107	3	6	1	5	3	6	2	2	9	8	6	2	1	1	1	6	1	7	6
Organochlorine Pesticides	20	0	0	1	1	0	1	0	2	1	2	1	1	1	0	0	0	2	3	2
PCBs	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
Organophosphorus Pesticides	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Alcohols	5	0	1	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Glycols	2	0	1	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Acids	4	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1	1	1	2	2

Metals and conventional parameters were detected and quantified in many of the samples and these observations are consistent with parameters listed in Table 5.9. However, the frequency of occurrence of other parameter classes was much lower: Table 5.23 summarizes the number of VOCs, SVOCs, PCBs, Pesticides, Alcohols, Glycols, and Acids observed in samples taken from each well. For the purposes of Table 5.23, if a particular parameter was detected in any sample from a single well, whether detected in one or all five (Day 0, 1, 5, 14 or 90) samples, it was considered to be one parameter.

- Between 1 and 7 of the 70 VOCs were detected in samples from well sites A through S. VOCs detected include:

1,2,3-Trichlorobenzene	Benzene	Isopropylbenzene
1,2,4-Trimethylbenzene	Bromoform	Naphthalene
1,3,5-Trimethylbenzene	Carbondisulfide	Toluene
2-Butanone	Chloroform	Xylenes
Acetone	Chloromethane	
Acrylonitrile	Ethylbenzene	

- Between 1 and 9 of the 107 SVOCs were detected in samples from well sites A through S. SVOCs detected include:

2,4-Dimethylphenol	Benzo(b)fluoranthene	Fluoranthene
2,6-Dichlorophenol	Benzo(ghi)perylene	Fluorene
2-Methylnaphthalene	Benzo(k)fluoranthene	Indeno(1,2,3-cd)pyrene
2-Methylphenol	Benzyl alcohol	N-Nitrosodiphenylamine
2-Picoline	bis(2-Chloroethyl) ether	Phenanthrene
3-Methylphenol & 4-Methylphenol	bis(2-Ethylhexyl) phthalate	Phenol
7,12-Dimethylbenz(a)anthracene	Dibenz(a,h)anthracene	Pyridine
Acetophenone	Di-n-butyl phthalate	Safrole
Benzo(a)pyrene	Diphenylamine	

- At most, 3 of the 20 Organochlorine Pesticides were detected. Organochlorine Pesticides detected include:

4,4 DDE	cyclohexane (gamma BHC)	endrin aldehyde
Aldrin	endosulfan I	Heptachlor
cyclohexane (beta BHC)	endosulfan II	heptachlor epoxide

- Only 1 (Aroclor 1248) of the 7 PCBs was detected, and that was only from one well site;
- Only 1 Organophosphorus Pesticide was analyzed for, but it was not detected in any sample;
- Of the 5 Alcohols analyzed for, 2 were detected at one well site and 1 each was detected at two well sites. Alcohols that were detected include 2-propanol and methanol;
- Of the 2 Glycols (Ethylene glycol and Propylene glycol) analyzed for, 1 each was detected at three well sites; and
- Of the 4 Acids analyzed for, 1 or 2 Acids (Acetic acid and Volatile Acids) were detected at several well sites.

Some parameters found in analytical results may be due to additives or supply water used in fracturing or drilling; some may be due to reactions between different additives; while others may have been mobilized from within the formation; still other parameters may have been contributed from multiple sources. Some of the volatile and semi-volatile analytical results may be traced back to potential laboratory contamination due to improper ventilation; due to chromatography column breakdown; or due to chemical breakdown of compounds during injection onto the instrumentation. Further study would be required to identify the specific origin of each parameter.

Nine pesticides and one PCB were identified by the MSC Study that were not identified by the flowback analytical results previously received from industry; all other parameters identified in the MSC study were already identified in the additives and/or flowback information received from industry.

Pesticides and PCBs do not originate within the shale play. If pesticides or PCBs were present in limited flowback samples in Pennsylvania or West Virgina, pesticides or PCBs would likely have been introduced to the shale or water during drilling or fracturing operations. Whether the pesticides or PCBs were introduced via additives or source water could not be evaluated with available information.

5.11.3.1 Temporal Trends in Flowback Water Composition

The composition of flowback water changes with time over the course of the flowback process, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water, including data from the MSC Study Report, indicate that:

- The concentrations of total dissolved solids (TDS), chloride, and barium increase;
- The levels of radioactivity increase,[111] and sometimes exceed MCLs;
- Calcium and magnesium hardness increases;
- Iron concentrations increase, unless iron-controlling additives are used;
- Sulfate levels decrease;
- Alkalinity levels decrease, likely due to use of acid; and
- Concentrations of metals increase.[112]

Available literature cited by URS corroborates the above summary regarding the changes in composition with time for TDS, chlorides, and barium. Fracturing fluids pumped into the well, and mobilization of materials within the shale may be contributing to the changes seen in hardness, sulfate, and metals. The specific changes would likely depend on the shale formation, fracturing fluids used and fracture operations control.

5.11.3.2 NORM in Flowback Water

Several radiological parameters were detected in flowback samples, as shown in Table 5.24.

---

[111] Limited data from vertical well operations in NY have reported the following ranges of radioactivity: alpha 22.41 – 18950 pCi/L; beta 9.68 – 7445 pCi/L; Radium^{226} 2.58 - 33 pCi/L.

[112] Metals such as aluminum, antimony, arsenic, barium, boron, cadmium, calcium, cobalt, copper, iron, lead, lithium, magnesium, manganese, molybdenum, nickel, potassium, radium, selenium, silver, sodium, strontium, thallium, titanium, and zinc have been reported in flowback analyses. It is important to note that each well did not report the presence of all these metals.

Table 5.24 - Concentrations of NORM constituents based on limited samples from PA and WV (Revised July 2011)

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
--	Gross Alpha	15	15	22.41	--	18,950	pCi/L
--	Gross Beta	15	15	62	--	7,445	pCi/L
7440-14-4	Total Alpha Radium	6	6	3.8	--	1,810	pCi/L
7440-14-4	Radium-226	3	3	2.58	--	33	pCi/L
7440-14-4	Radium-228	3	3	1.15	--	18.41	pCi/L

5.12 Flowback Water Treatment, Recycling and Reuse

Operators have expressed the objective of maximizing their re-use of flowback water for subsequent fracturing operations at the same well pad or other well pads; this practice is increasing and continuing to evolve in the Marcellus Shale.[113] Reuse involves either straight dilution of the flowback water with fresh water or the introduction on-site of more sophisticated treatment options prior to flowback reuse. Originally operators focused on treating flowback water using polymers and flocculants to precipitate out and remove metals, but more recently operators have begun using filtration technologies to achieve the same goal.[114] As stated above, various on-site treatment technologies may be employed prior to reuse of flowback water. Regardless of the treatment objective, whether for reuse or direct discharge, the three basic issues that need consideration when developing water treatment technologies are:[115]

1. Influent (i.e., flowback water) parameters and their concentrations;
2. Parameters and their concentrations allowable in the effluent (i.e., in the reuse water); and
3. Disposal of residuals.

Untreated flowback water composition is discussed in Section 5.11.3. Table 5.25 summarizes allowable concentrations after treatment (and prior to potential additional dilution with fresh water).[116]

---

[113] ALL Consulting, 2010, p. 73.

[114] ALL Consulting, 2010, p. 73.

[115] URS, 2009, p. 5-2.

[116] URS, 2009, p. 5-3.

Table 5.25 - Maximum allowable water quality requirements for fracturing fluids, based on input from one expert panel on Barnett Shale (Revised July 2011)

Constituent	Concentration
Chlorides	3,000 - 90,000 mg/L
Calcium	350 - 1,000 mg/L
Suspended Solids	< 50 mg/L
Entrained oil and soluble organics	< 25 mg/L
Bacteria	< 100 cells/100 ml
Barium	Low levels

The following factors influence the decision to utilize on-site treatment and the selection of specific treatment options:[117]

Operational

- Flowback fluid characteristics, including scaling and fouling tendencies;
- On-site space availability;
- Processing capacity needed;
- Solids concentration in flowback fluid, and solids reduction required;
- Concentrations of hydrocarbons in flowback fluid, and targeted reduction in hydrocarbons;[118]
- Species and levels of radioactivity in flowback;
- Access to freshwater sources;
- Targeted recovery rate;
- Impact of treated water on efficacy of additives; and
- Availability of residuals disposal options.

---

[117] URS, 2009, p. 5-3.

[118] Liquid hydrocarbons have not been detected in all Marcellus Shale gas analyses.

Cost

- Capital costs associated with treatment system;
- Transportation costs associated with freshwater; and
- Increase or decrease in fluid additives from using treated flowback fluid.

Environmental

- On-site topography;
- Density of neighboring population;
- Proximity to freshwater sources;
- Other demands on freshwater in the vicinity; and
- Regulatory environment.

5.12.1 Physical and Chemical Separation[119]

Some form of physical and/or chemical separation will be required as a part of on-site treatment. Physical and chemical separation technologies typically focus on the removal of oil and grease[120] and suspended matter from flowback. Modular physical and chemical separation units have been used in the Barnett Shale and Powder River Basin plays.

Physical separation technologies include hydrocyclones, filters, and centrifuges; however, filtration appears to be the preferred physical separation technology. The efficiency of filtration technologies is controlled by the size and quantity of constituents within the flowback fluid as well as the pore size and total contact area of the membrane. To increase filtration efficiency, one vendor provides a vibrating filtration unit (several different pore sizes are available) for approximately $300,000; this unit can filter 25,000 gpd.

Microfiltration has been shown to be effective in lab-scale research, nanofiltration has been used to treat production brine from off-shore oil rigs, and modular filtration units have been used in

---

[119] URS, 2009, p. 5-6.

[120] Oil and grease are not expected in the Marcellus.

the Barnett Shale and Powder River Basin.[121] Nanofiltration has also been used in Marcellus development in Pennsylvania, though early experience there indicates that the fouling of filter packs has been a limiting constraint on its use.[122]

Chemical separation utilizes coagulants and flocculants to break emulsions (dissolved oil) and to remove suspended particles. The companion process of precipitation is accomplished by manipulating flowback chemistry such that constituents within the flowback (in particular, metals) will precipitate out of solution. This can also be performed sequentially, so that several chemicals will precipitate, resulting in cleaner flowback.

Separation and precipitation are used as pre-treatment steps within multi-step on-site treatment processes. Chemical separation units have been used in the Barnett Shale and Powder River Basin plays, and some vendors have proprietary designs for sequential precipitation of metals for potential use in the Marcellus Shale play.[123]

If flowback is to be treated solely for blending and re-use as fracturing fluid, chemical precipitation may be one of the only steps needed. By precipitation of scale-forming metals (e.g., barium, strontium, calcium, magnesium), minimal excess treatment may be required. Prices for chemical precipitation systems are dependent upon the cost of the treatment chemicals; one vendor quoted a 15 gpm system for $450,000 or a 500 gpm system for approximately $1 million, with costs ranging from $0.50 to $3.00 per barrel.

5.12.2 Dilution

The dilution option involves blending flowback water with freshwater to make it usable for future fracturing operations. Because high concentrations of different parameters in flowback water may adversely affect the desired fracturing fluid properties, 100% recycling is not always possible without employing some form of treatment.[124,125] Concentrations of chlorides, calcium, magnesium, barium, carbonates, sulfates, solids and microbes in flowback water may be too high

---

[121] URS 2011, p 5-6.

[122] Yoxtheimer, 2011 (personal communication).

[123] URS 2011, p 5-7.

[124] URS, 2009, p. 5-1.

[125] ALL Consulting, 2010, p. 73.

to use as-is, meaning that some form of physical and/or chemical separation is typically needed prior to recycling flowback.[126] In addition, the practice of blending flowback with freshwater involves balancing the additional freshwater water needs with the additional additive needs.[127] For example, the demand for friction reducers increases when the chloride concentration increases; the demand for scale inhibitors increases when concentrations of calcium, magnesium, barium, carbonates, or sulfates increase; biocide requirements increase when the concentration of microbes increases. These considerations do not constrain reuse because both the dilution ratio and the additive concentrations can be adjusted to achieve the desired properties of the fracturing fluid.[128] In addition, service companies and chemical suppliers may develop additive products that are more compatible with the aforementioned flowback water parameters.

5.12.2.1 Reuse

The SRBC's reporting system for water usage within the Susquehanna River Basin (SRB) has provided a partial snapshot of flowback water reuse specific to Marcellus development. For the period June 1, 2008 to June 1, 2011, operators in the SRB in Pennsylvania reused approximately 311 million gallons of the approximately 2.14 billion gallons withdrawn and delivered to Marcellus well pads. The SRBC data indicate that an average of 4.27 million gallons of water were used per well; this figure reflects an average of 3.84 million gallons of fresh water and 0.43 million gallons of reused flowback water per well.[129] The current limiting factors on flowback water reuse are the volume of flowback water recovered and the timing of upcoming fracture treatments.[130] Treatment and reuse of flowback water on the same well pad reduces the number of truck trips needed to haul flowback water to another destination.

Operators may propose to store flowback water prior to or after dilution in on-site tanks, which are discussed in Section 5.11.2. The tanks may be set up to segregate flowback based on estimated water quality. Water that is suitable for reuse with little or no treatment can be stored separately from water that requires some degree of treatment, and any water deemed unsuitable

---

[126] URS, 2009, p. 5-2.

[127] URS, 2009, p. 5-2.

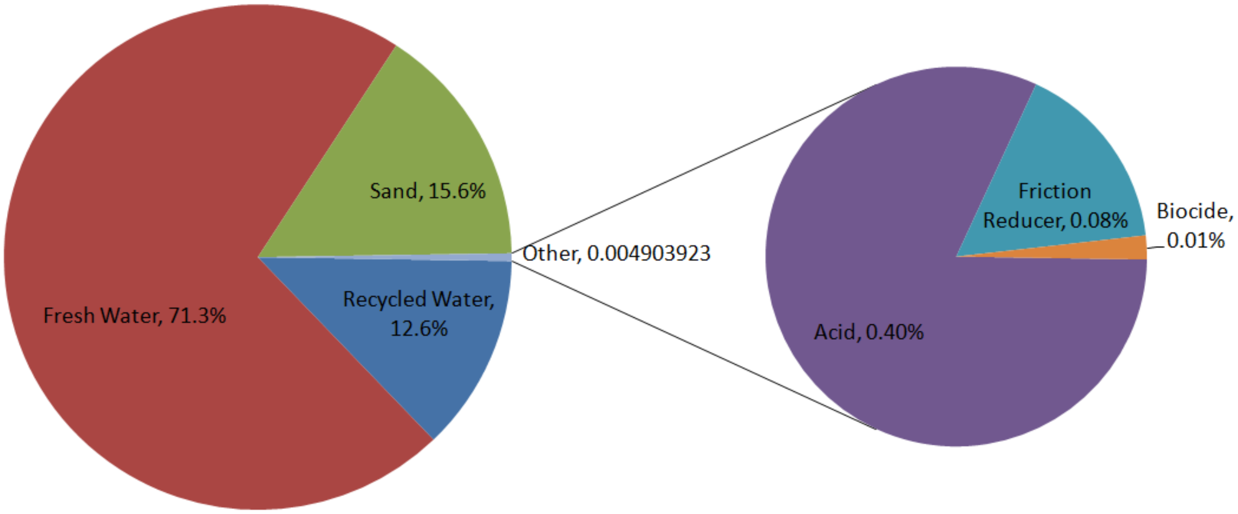
[128] ALLConsulting, 2010, p. 74.

[129] SRBC, 2011.

[130] ALL Consulting, 2010, p. 74.

for reuse can then be separated for appropriate disposal.[131] An example of the composition of a fracturing solution that includes recycled flowback water is shown in Figure 5.6.

Figure 5.6 - Example Fracturing Fluid Composition Including Recycled Flowback Water (New July 2011)



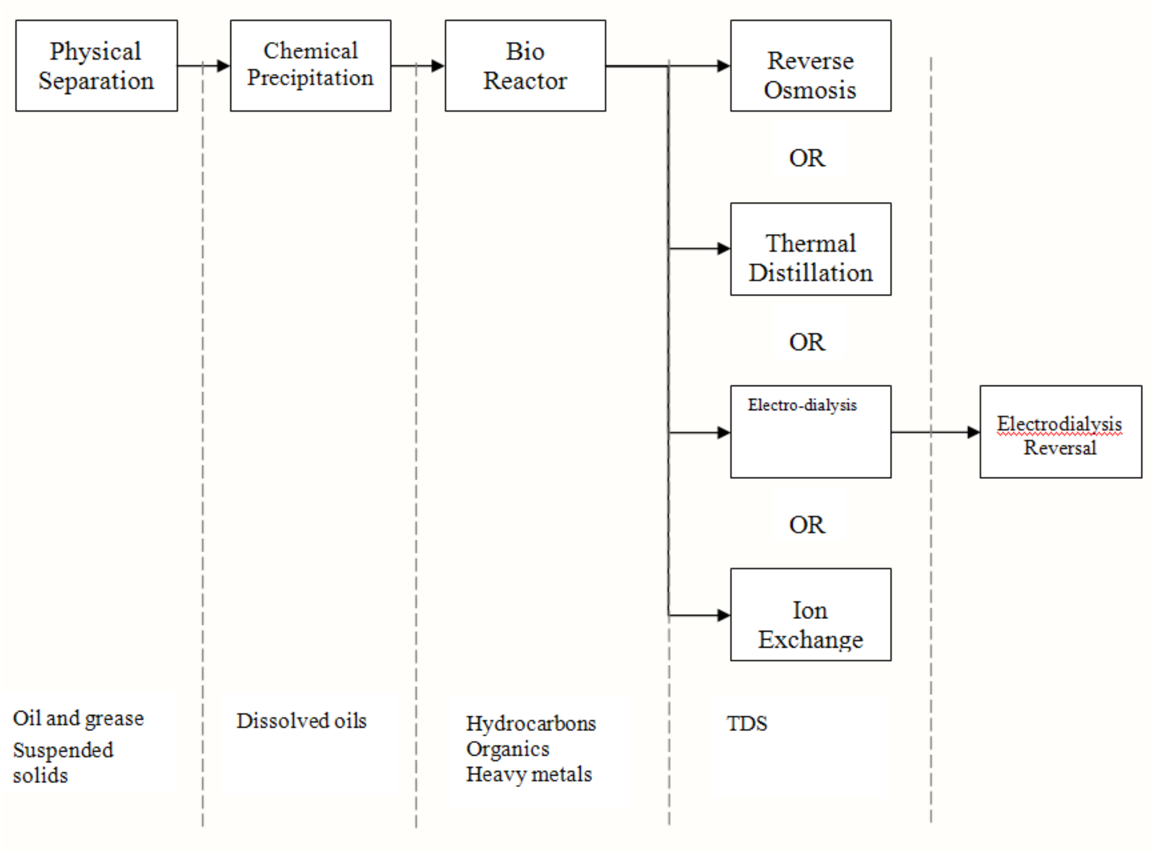
---

[131] ALL Consulting, 2010, p. 74.

5.12.3 Other On-Site Treatment Technologies[132]

One example of an on-site treatment technology configuration is illustrated in Figure 5.7. The parameters treated are listed at the bottom of the figure. The next few sections present several on-site treatment technologies that have been used to some extent in other U.S. gas-shale plays.

Figure 5.7 - One configuration of potential on-site treatment technologies.



5.12.3.1 Membranes / Reverse Osmosis

Membranes are an advanced form of filtration, and may be used to treat TDS in flowback. The technology allows water - the permeate - to pass through the membrane, but the membrane blocks passage of suspended or dissolved particles larger than the membrane pore size. This method may be able to treat TDS concentrations up to approximately 45,000 mg/L, and produce an effluent with TDS concentrations between 200 and 500 mg/L. This technology generates a

---

[132] URS, 2009, p. 5-4.

residual - the concentrate - that would need proper disposal. The flowback water recovery rate for most membrane technologies is typically between 50-75 percent. Membrane performance may be impacted by scaling and/or microbiological fouling; therefore, flowback water would likely require extensive pre-treatment before it is sent through a membrane.

Reverse osmosis (RO) is a membrane technology that uses osmotic pressure on the membrane to provide passage of high-quality water, producing a concentrated brine effluent that will require further treatment and disposal. Reverse osmosis is a well-proven technology and is frequently used in desalination projects, in both modular and permanent configurations, though it is less efficient under high TDS concentrations. High TDS concentrations, such as in Marcellus flowback, [133] will likely result in large quantities of concentrated brine (also referred to as "reject") that will require further treatment or disposal. When designing treatment processes, several vendors use RO as a primary treatment (with appropriate pre-treatment prior to RO); and then use a secondary treatment method for the concentrated brine. The secondary treatment can be completed on-site, or the concentrated brine can be trucked to a centralized brine treatment facility.

Modular membrane technology units have been used in different regions for many different projects, including the Barnett Shale. Some firms have developed modular RO treatment units, which could potentially be used in the Marcellus.[134]

5.12.3.2 Thermal Distillation

Thermal distillation utilizes evaporation and crystallization techniques that integrate a multi-effect distillation column, and this technology may be used to treat flowback water with a large range of parameter concentrations. For example, thermal distillation may be able to treat TDS concentrations from 5,000 to over 150,000 mg/L, and produce water with TDS concentrations between 50 and 150 mg/L. The resulting residual salt would need appropriate disposal. This technology is resilient to fouling and scaling, but is energy intensive and has a large footprint.

Modular thermal distillation units have been used in the Barnett Shale, and have begun to be

---

[133] URS, 2011, p. 4-37.

[134] URS, 2011, p. 5-7.

used in the Marcellus Shale in Pennsylvania. In addition to the units that are already in use, several vendors have designs ready for testing, potentially further decreasing costs in the near future.[135]

5.12.3.3 Ion Exchange

Ion exchange units utilize different resins to preferentially remove certain ions. When treating flowback, the resin would be selected to preferentially remove sodium ions. The required resin volume and size of the ion exchange vessel would depend on the salt concentration and flowback volume treated.

The Higgins Loop is one version of ion exchange that has been successfully used in Midwest coal bed methane applications. The Higgins Loop uses a continuous countercurrent flow of flowback fluid and ion exchange resin. High sodium flowback fluid can be fed into the absorption chamber to exchange for hydrogen ions. The strong acid-cation resin is advanced to the absorption chamber through a unique resin pulsing system.

Modular ion exchange units have been used in the Barnett Shale.

5.12.3.4 Electrodialysis/Electrodialysis Reversal

These treatment units are configured with alternating stacks of cation and anion membranes that allow passage of flowback fluid. Electric current applied to the stacks forces anions and cations to migrate in different directions.

Electrodialysis Reversal (EDR) is similar to electrodialysis, but its electric current polarity may be reversed as needed. This current reversal acts as a backwash cycle for the stacks which reduces scaling on membranes. EDR offers lower electricity usage than standard reverse osmosis systems and can potentially reduce salt concentrations in the treated water to less than 200 mg/L. Modular electrodialysis units have been used in the Barnett Shale and Powder River Basin plays.

Table 5.26 compares EDR and RO by outlining key characteristics of both technologies.

---

[135] URS, 2011 p. 5-8.

Table 5.26 - Treatment capabilities of EDR and RO Systems

Criteria	**EDR**	**RO**
Acceptable influent TDS (mg/L)	400-3,000	100-15,000
Salt removal capacity	50-95%	90-99%
Water recovery rate	85-94%	50-75%
Allowable Influent Turbidity	Silt Density Index (SDI) < 12	SDI < 5
Operating Pressure	<50 psi	> 100 psi
Power Consumption	Lower for <2,500 mg/L TDS	Lower for >2,500 mg/L TDS
Typical Membrane Life	7-10 years	3-5 years

5.12.3.5 Ozone/Ultrasonic/Ultraviolet

These technologies are designed to oxidize and separate hydrocarbons and heavy metals, and to oxidize biological films and bacteria from flowback water. The microscopic air bubbles in supersaturated ozonated water and/or ultrasonic transducers cause oils and suspended solids to float. Some vendors have field-tested the companion process of hydrodynamic cavitation, in which microscopic ozone bubbles implode, resulting in very high temperatures and pressures at the liquid-gas interface, converting the ozone to hydroxyl radicals and oxygen gas. The high temperatures and the newly-formed hydroxyl radicals quickly oxidize organic compounds.[136] Hydrodynamic cavitation has been used in field tests in the Fayetteville and Woodford Shale plays, but its use has not gained traction in the Marcellus play.[137]

Some vendors include ozone treatment technologies as one step in their flowback treatment process, including treatment for blending and re-use of water in drilling new wells. Systems incorporating ozone technology have been successfully used and analyzed in the Barnett Shale.[138]

---

[136] NETL, 2010.

[137] Yoxtheimer, 2011.

[138] URS, 2011 p. 5-9.

5.12.3.6 Crystallization/Zero Liquid Discharge

Zero liquid discharge (ZLD) follows the same principles as physical and chemical separation (precipitation, centrifuges, etc.) and evaporation, however a ZLD process ensures that all liquid effluent is of reusable or dischargeable quality. Additionally, any concentrate from the treatment process will be crystallized and will either be used in some capacity on site, will be offered for sale as a secondary product, or will be treated in such a way that it will meet regulations for disposal within a landfill. ZLD treatment is a relatively rare, expensive treatment process, and while some vendors suggest that the unit can be setup on the well pad, a more cost-effective use of ZLD treatment will be at a centralized treatment plant located near users of the systems' byproducts. In addition to the crystallized salts produced by ZLD, treated effluent water and/or steam will also be a product that can be used by a third party in some industrial or agricultural setting.

ZLD treatment systems are in use in a variety of industries, but none have been implemented in a natural gas production setting yet. Numerous technology vendors have advertized ZLD as a treatment option in the Marcellus, but the economical feasibility of such a system has not yet been demonstrated.[139]

5.12.4 Comparison of Potential On-Site Treatment Technologies

A comparison of performance characteristics associated with on-site treatment technologies is provided in Table 5.27[140]

---

[139] URS, 2011 p. 5-9.

[140] URS, 2009, p. 5-8.

Table 5.27 - Summary of Characteristics of On-Site Flowback Water Treatment Technologies (Updated July 2011)[141]

Characteristic	Filtration	Ion Exchange	Reverse Osmosis	EDR	Thermal Distillation	Ozone / Ultrasonic / Ultraviolet
Energy Cost	Low	Low	Moderate	High	High	Low
Energy Usage vs. TDS	N/A	Low	Increase	High Increase	Independent	Increase
Applicable to	All Water types	All Water types	Moderate TDS	High TDS	High TDS	All Water types
Plant / Unit size	Small / Modular	Small / Modular	Modular	Modular	Large	Small / Modular
Microbiological Fouling	Possible	Possible	Possible	Low	N/A	Possible
Complexity of Technology	Low	Low	Moderate / High Maintenance	Regular Maintenance	Complex	Low
Scaling Potential	Low	Low	High	Low	Low	Low
Theoretical TDS Feed Limit (mg/L)	N/A	N/A	32,000	40,000	100,000+	Depends on turbidity
Pretreatment Requirement	N/A	Filtration	Extensive	Filtration	Minimal	Filtration
Final Water TDS	No impact	200-500 ppm	200-500 ppm	200-1000 ppm	< 10 mg/L	Variable
Recovery Rate (Feed TDS >20,000 mg/L)	N/A	N/A	30-50%	60-80%	75-85%	Variable

5.13 Waste Disposal

5.13.1 Cuttings from Mud Drilling

The 1992 GEIS discusses on-site burial of cuttings generated during compressed air drilling. This option is also viable for cuttings generated during drilling with fresh water as the drilling fluid. However, cuttings that are generated during drilling with polymer- or oil-based muds are considered industrial non-hazardous waste and therefore must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill. In New York State the NORM in cuttings is not precluded by regulation from disposal in a solid waste

---

[141] URS, 2011, p. 5-9

landfill, though well operators should consult with the operators of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility.

5.13.2 Reserve Pit Liner from Mud Drilling

The 1992 GEIS discusses on-site burial, with the landowner's permission, of the plastic liner used for the reserve pit for air-drilled wells. This option is also viable for wells where fresh-water is the drilling fluid. However, pit liners for reserve pits where polymer- or oil-based drilling muds are used must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill.

5.13.3 Flowback Water

As discussed in Section 5.12, options exist or are being developed for treatment, recycling and reuse of flowback water. Nevertheless, proper disposal is required for flowback water that is not reused. Factors which could result in a need for disposal instead of reuse include lack of reuse opportunity (i.e., no other wells being fractured within reasonable time frames or a reasonable distance), prohibitively high contaminant concentrations which render the water untreatable to usable quality, or unavailability or infeasibility of treatment options for other reasons.

Flowback water requiring disposal is considered industrial wastewater, like many other water-use byproducts. The Department has an EPA-approved program for the control of wastewater discharges. Under New York State law, the program is called the State Pollutant Discharge Elimination System (SPDES). The program controls point source discharges to ground waters and surface waters. SPDES permits are issued to wastewater dischargers, including POTWs, and include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

Potential flowback water disposal options discussed in the 1992 GEIS include:

- injection wells, which are regulated under both the Department's SPDES program and the federal Underground Injection Control (UIC) program;
- municipal sewage treatment facilities (POTWs); and
- out-of-state industrial treatment plants.

Road spreading for dust control and de-icing (by a Part 364 Transporter with local government approval) is also discussed in the 1992 GEIS as a general disposition method used in New York for well-related fluids, primarily production brine (not an option for flowback water). Use of existing or new private in-state waste water treatment plants and injection for enhanced resource recovery in oil fields have also been suggested. More information about each of these options is presented below and a more detailed discussion of the potential environmental impacts and how they are mitigated is presented in Chapters 6 and 7.

5.13.3.1 Injection Wells

Discussed in Chapter 15 of the 1992 GEIS, injection wells for disposal of brine associated with oil and gas operations are classified as Class IID in EPA's UIC program and require federal permits. Under the Department's SPDES program, the use of these wells has been categorized and regulated as industrial discharge. The primary objective of both programs is protection of underground sources of drinking water, and neither the EPA nor the Department issues a permit without a demonstration that injected fluids will remain confined in the disposal zone and isolated from fresh water aquifers. As noted in the 1992 Findings Statement, the permitting process for brine disposal wells "require[s] an extensive surface and subsurface evaluation which is in effect a SEIS addressing technical issues. An additional site-specific environmental assessment and SEQRA determination are required."

UIC permit requirements will be included by reference in the SPDES permit, and the Department may propose additional monitoring requirements and/or discharge limits for inclusion in the SPDES permit. A well permit issued by DMN is also required to drill or convert a well deeper than 500 feet for brine disposal. This permit is not issued until the required UIC and SPDES permits have been approved. More information about the required analysis and mitigation measures considered during this review is provided in Chapter 7. Because of the 1992 finding that brine disposal wells require site-specific SEQRA review, mitigation measures are discussed in Chapter 7 for informational purposes only and are not being proposed on a generic basis.

5.13.3.2 Municipal Sewage Treatment Facilities

Municipal sewage treatment facilities (also called POTWs) are regulated by the Department's DOW. POTWs typically discharge treated wastewater to surface water bodies, and operate under SPDES permits which include specific discharge limitations and monitoring requirements. In general, POTWs must have a Department-approved pretreatment program for accepting any industrial waste. POTWs must also notify the Department of any new industrial waste they plan to receive at their facility. POTWs are required to perform certain analyses to ensure they can handle the waste without upsetting their system or causing a problem in the receiving water. Ultimately, the Department needs to approve such analysis and modify SPDES permits as needed to insure water quality standards in receiving waters are maintained at all times. More detailed discussion of the potential environmental impacts and how they are mitigated is presented in Chapters 6 and 7.

5.13.3.3 Out-of-State Treatment Plants

The only regulatory role the Department has over disposal of flowback water (or production brine) at out-of-state municipal or industrial treatment plants is that transport of these fluids, which are considered industrial waste, must be by a licensed Part 364 Transporter.

For informational purposes, Table 5.28 lists out-of-state plants that were proposed in actual well permit applications for disposition of flowback water recovered in New York. The regulatory regimes in other states for treatment of this waste stream are evolving, and it is unknown whether disposal at the listed plants remains feasible.

Table 5.28 - Out-of-state treatment plants proposed for disposition of NY flowback water

Treatment Facility	**Location**	**County**
Advanced Waste Services	New Castle, PA	Lawrence
Eureka Resources	Williamsport, PA	Lycoming
Lehigh County Authority Pretreatment Plant	Fogelsville, PA	Lehigh
Liquid Assets Disposal	Wheeling, WV	Ohio
Municipal Authority of the City of McKeesport	McKeesport, PA	Allegheny
PA Brine Treatment, Inc.	Franklin, PA	Venango
Sunbury Generation	Shamokin Dam, PA	Snyder
Tri-County Waste Water Management	Waynesburg, PA	Greene
Tunnelton Liquids Co.	Saltsburg, PA	Indiana
Valley Joint Sewer Authority	Athens, PA	Bradford
Waste Treatment Corporation	Washington, PA	Washington

5.13.3.4 Road Spreading

Consistent with past practice regarding flowback water disposal, in January 2009, the Department's Division of Solid and Hazardous Materials (DSHM), which was then responsible for oversight of the Part 364 program, released a notification to haulers applying for, modifying, or renewing their Part 364 permit that flowback water from any formation including the Marcellus may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to DMN. This notification also addressed production brine and is included as Appendix 12. (Because of organizational changes within the Department since 2009, the Part 364 program is now overseen by the Division of Environmental Remediation (DER). As discussed in Chapter 7, BUDs for reuse of production brine from Marcellus Shale will not be issued until additional data on NORM content is available and evaluated.)

5.13.3.5 Private In-State Industrial Treatment Plants

Industrial facilities could be constructed or converted in New York to treat flowback water (and production brine). Such facilities would require a SPDES permit for any discharge. Again, the SPDES permit for a dedicated treatment facility would include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

5.13.3.6 Enhanced Oil Recovery

Waterflooding is an enhanced oil recovery technique whereby water is injected into partially depleted oil reservoirs to displace additional oil and increase recovery. Waterflood operations in New York are regulated under Part 557 of the Department's regulations and under the EPA's Underground Injection Control Program.

EPA reviews proposed waterflood injectate to determine the threat of endangerment to underground sources of drinking water. Operations that are authorized by rule are required to submit an analysis of the injectate anytime it changes, and operations under permit are required to modify their permits to inject water from a new source. At this time, no waterflood operations in New York have EPA approval to inject flowback water.

5.13.4 Solid Residuals from Flowback Water Treatment

URS Corporation reports that residuals disposal from the limited on-site treatment currently occurring generally consists of injection into disposal wells.[142] Other options would be dependent upon the nature and composition of the residuals and would require site-specific consultation with the Department's Division of Materials Management (DMM). Transportation would require a Part 364 Waste Transporters' Permit.

5.14 Well Cleanup and Testing

Wells are typically tested after drilling and stimulation to determine their productivity, economic viability, and design criteria for a pipeline gathering system if one needs to be constructed. If no gathering line exists, well testing necessitates that produced gas be flared. However, operators have reported that for Marcellus Shale development in the northern tier of Pennsylvania, flaring is minimized by construction of the gathering system ahead of well completion. Flaring is necessary during the initial 12 to 24 hours of flowback operations while the well is producing a high ratio of flowback water to gas, but no flow testing that requires an extended period of flaring is conducted. Operators report that without a gathering line in place, initial cleanup or

---

[142] URS, 2009, p. 5-3.

testing that require flaring could last for 3 days per well.[143] Under the SGEIS, permit conditions would prohibit flaring during completion operations if a gathering line is in place.

5.15 Summary of Operations Prior to Production

Table 5.29 summarizes the primary operations that may take place at a multi-well pad prior to the production phase, and their typical durations. This tabulation assumes that a smaller rig is used to drill the vertical wellbore and a larger rig is used for the horizontal wellbore. Rig availability and other parameters outside the operators' control may affect the listed time frames. As explained in Section 5.2, no more than two rigs would operate on the well pad concurrently.

Note that the early production phase at a pad may overlap with the activities summarized in Table 5.29, as some wells may be placed into production prior to drilling and completion of all the wells on a pad. All pre-production operations for an entire pad must be concluded within three years or less, in accordance with ECL §23-0501. Estimated duration of each operation may be shorter or longer depending on site specific circumstances.

Table 5.29 - Primary Pre-Production Well Pad Operations (Revised July 2011)

Operation	Materials and Equipment	Activities	Duration
Access Road and Well Pad Construction	Backhoes, bulldozers and other types of earth-moving equipment.	Clearing, grading, pit construction, placement of road materials such as geotextile and gravel.	Up to 4 weeks per well pad
Vertical Drilling with Smaller Rig	Drilling rig, fuel tank, pipe racks, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing surface casing, truck trips for delivery of equipment and cement. Delivery of equipment for horizontal drilling may commence during late stages of vertical drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Horizontal Drilling with Larger Rig		Transport, assembly and setup, or repositioning on site of large rig and ancillary equipment.	5 – 30 days per well[144]

---

[143] ALL Consulting, 2010, pp. 10-11.

[144] The shorter end of the time frame for drilling preparations applies if the rig is already at the well pad and only needs to be repositioned. The longer end applies if the rig would be brought from off-site and is proportional to the distance which the rig would be moved. This time frame would occur prior to vertical drilling if the same rig is used for the vertical and horizontal portions of the wellbore.

Operation	Materials and Equipment	Activities	Duration
Horizontal Drilling	Drilling rig, mud system (pumps, tanks, solids control, gas separator), fuel tank, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing production casing, truck trips for delivery of equipment and cement. Deliveries associated with hydraulic fracturing may commence during late stages of horizontal drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Hydraulic Fracturing		Rig down and removal or repositioning of drilling equipment including possible changeover to workover rig to clean out well and run tubing-conveyed perforating equipment. Wireline truck on site to run cement bond log (CBL). Truck trips for delivery of temporary tanks, water, sand, additives and other fracturing equipment. Deliveries may commence during late stages of horizontal drilling.	30 – 60 days per well, or per well pad if all wells treated during one mobilization
Hydraulic Fracturing Procedure	Temporary water tanks, generators, pumps, sand trucks, additive delivery trucks and containers (see Section 5.6.1), blending unit, personnel vehicles, associated outbuildings, including computerized monitoring equipment.	Fluid pumping, and use of wireline equipment between pumping stages to raise and lower tools used for downhole well preparation and measurements. Computerized monitoring. Continued water and additive delivery.	2 – 5 days per well, including approximately 40 to 100 hours of actual pumping
Fluid Return (Flowback) and Treatment	Gas/water separator, flare stack, temporary water tanks, mobile water treatment units, trucks for fluid removal if necessary, personnel vehicles.	Rig down and removal or repositioning of fracturing equipment; controlled fluid flow into treating equipment, tanks, lined pits, impoundments or pipelines; truck trips to remove fluid if not stored on site or removed by pipeline.	2 – 8 weeks per well, may occur concurrently for several wells
Waste Disposal	Earth-moving equipment, pump trucks, waste transport trucks.	Pumping and excavation to empty/reclaim reserve pit(s). Truck trips to transfer waste to disposal facility. Truck trips to remove temporary water storage tanks.	Up to 6 weeks per well pad
Well Cleanup and Testing	Well head, flare stack, brine tanks. Earth-moving equipment.	Well flaring and monitoring. Truck trips to empty brine tanks. Gathering line construction may commence if not done in advance.	½ - 30 days per well

5.16 Natural Gas Production

5.16.1 Partial Site Reclamation

Subsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production.

Well pad size during the production phase will be influenced on a site-specific basis by topography and generally by the space needed to support production activities and well servicing. According to operators, multi-well pads will average 1.5 acres in size during the long-term production phase, after partial reclamation.

5.16.2 Gas Composition

5.16.2.1 Hydrocarbons

As discussed in Chapter 4 and shown on the maps accompanying the discussion in that section, most of the Utica Shale and most of the Marcellus Shale “fairway” are in the dry gas window as defined by thermal maturity and vitrinite reflectance. In other words, the shales would not be expected to produce liquid hydrocarbons such as oil or condensate. This is corroborated by gas composition analyses provided by one operator for wells in the northern tier of Pennsylvania and shown in Table 5.30.

Table 5.30 - Marcellus Gas Composition from Bradford County, PA

Mole percent samples from Bradford Co., PA												
Sample Number	**Nitrogen**	**Carbon Dioxide**	**Methane**	**Ethane**	**Propane**	**i-Butane**	**n-Butane**	**i-Pentane**	**n-Pentane**	**Hexanes +**	**Oxygen**	**sum**
1	0.297	0.063	96.977	2.546	0.107		0.01					100
2	0.6	0.001	96.884	2.399	0.097	0.004	0.008	0.003	0.004			100
3	0.405	0.085	96.943	2.449	0.106	0.003	0.009					100
4	0.368	0.046	96.942	2.522	0.111	0.002	0.009					100
5	0.356	0.067	96.959	2.496	0.108	0.004	0.01					100
6	1.5366	0.1536	97.6134	0.612	0.0469					0.0375		100
7	2.5178	0.218	96.8193	0.4097	0.0352							100
8	1.2533	0.1498	97.7513	0.7956	0.0195		0.0011			0.0294		100
9	0.2632	0.0299	98.0834	1.5883	0.0269	0.0000	0.0000	0.0000	0.0000	0.0000	0.0083	100
10	0.4996	0.0551	96.9444	2.3334	0.0780	0.0157	0.0167	0.0000	0.0000	0.0000	0.0571	100
11	0.1910	0.0597	97.4895	2.1574	0.0690	0.0208	0.0126	0.0000	0.0000	0.0000	0.0000	100
12	0.2278	0.0233	97.3201	2.3448	0.0731	0.0000	0.0032	0.0000	0.0000	0.0000	0.0077	100

ICF International, reviewing the above data under contract to NYSERDA, notes that samples 1, 3, 4 had no detectable hydrocarbons greater than n-butane. Sample 2 had no detectable hydrocarbons greater than n-pentane. Based on the low VOC content of these compositions, pollutants such as BTEX are not expected.[145] BTEX would normally be trapped in liquid phase with other components like natural gas liquids, oil or water. Fortuna Energy reports that it has sampled for benzene, toluene, and xylene and has not detected it in its gas samples or water analyses.

5.16.2.2 Hydrogen Sulfide

As further reported by ICF, sample number 1 in Table 5.30 included a sulfur analysis and found less than 0.032 grams sulfur per 100 cubic feet. The other samples did not include sulfur analysis. Chesapeake Energy reported in 2009 that no hydrogen sulfide had been detected at any of its active interconnects in Pennsylvania. Also in 2009, Fortuna Energy (now Talisman Energy) reported testing for hydrogen sulfide regularly with readings of 2 to 4 ppm during a brief period on one occasion in its vertical Marcellus wells, and that its presence had not recurred since. More recently, it has been reported to the Department that, beyond minor detections with mudlogging equipment, there is no substantiated occurrence of H_2S in Marcellus wells in the northern tier of Pennsylvania.[146]

5.16.3 Production Rate

Long-term production rates are difficult to predict accurately for a play that has not yet been developed or is in the very early stages of development. One operator has indicated that its Marcellus production facility design will have a maximum capacity of either 6 MMcf/d or 10 MMcf/d, whichever is appropriate. IOGA-NY provided production estimates based on current information regarding production experience in Pennsylvania, but also noted the following caveats:

- The production estimates are based on 640-acre pad development with horizontal wells in the Marcellus fairway. Vertical wells and off-fairway development will vary.

---

[145] ICF Task 2, 2009, pp. 29-30.

[146] ALL Consulting, 2010, p. 49.

- The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania.

The per-well production estimates provided by IOGA-NY are as follows:

High Estimate

- Year 1 – initial rate of 8.72 MMcf/d declining to 3.49 MMcf/d.
- Years 2 to 4 – 3.49 MMcf/d declining to 1.25 MMcf/d.
- Years 5 to 10 – 1.25 MMcf/d declining to 0.55 MMcf/d.
- Years 11 and after – 0.55 MMcf/d declining at 5% per annum.
- The associated estimated ultimate recovery (EUR) is approximately 9.86 Bcf.

Low Estimate

- Year 1 – initial rate of 3.26 MMcf/d declining to 1.14 MMcf/d.
- Years 2 to 4 – 1.14 MMcf/d declining to 0.49 MMcf/d.
- Years 5 to 10 – 0.49 MMcf/d declining to 0.29 MMcf/d.
- Years 11 and after – 0.29 MMcf/d declining at 5% per annum.
- The associated EUR is approximately 2.28 Bcf.[147]

5.16.4 Well Pad Production Equipment

In addition to the assembly of pressure-control devices and valves at the top of the well known as the "wellhead," "production tree" or "Christmas tree," equipment at the well pad during the production phase will likely include:

- A small inline heater that is in use for the first 6 to 8 months of production and during winter months to ensure freezing does not occur in the flow line due to Joule-Thompson effect (each well or shared);
- A two-phase gas/water separator;
- Gas metering devices (each well or shared);
- Water metering devices (each well or shared); and
- Brine storage tanks (shared by all wells).

---

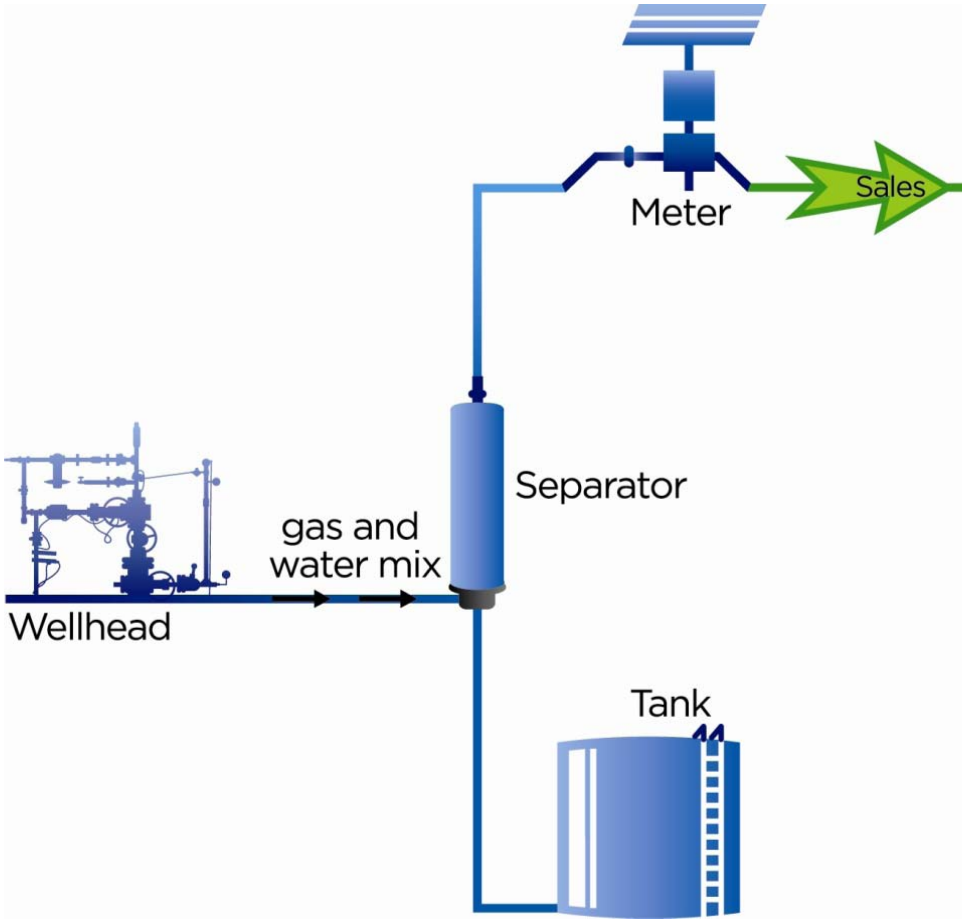
[147] ALL Consulting, 2011, p. 2.

In addition:

- A well head compressor may be added during later years after gas production has declined; and
- A triethylene glycol (TEG) dehydrator may be located at some well sites, although typically the gas is sent to a gathering system for compression and dehydration at a compressor station.

Produced gas flows from the wellhead to the separator through a two- to three-inch diameter pipe (flow line). The operating pressure in the separator will typically be in the 100 to 200 psi range depending on the stage of the wells' life. At the separator, water will be removed from the gas stream via a dump valve and sent by pipe (water line) to the brine storage tanks. The gas continues through a meter and to the departing gathering line, which carries the gas to a centralized compression facility (see Figure 5.8).

Figure 5.8 – Simplified Illustration of Gas Production Process



5.16.5 Brine Storage

Based on experience to date in the northern tier of Pennsylvania, one operator reports that brine production has typically been less than 10 barrels per day after the initial flowback operation and once the well is producing gas. Another operator reports that the rate of brine production during the production phase is about to 5 - 20 barrels per MMcf of gas produced.

One or more brine tanks will be installed on-site, along with truck loading facilities. At least one operator has indicated the possibility of constructing pipelines to move brine from the site, in which case truck loading facilities would not be necessary. Operators monitor brine levels in the tanks at least daily, with some sites monitored remotely by telemetric devices capable of sending alarms or shutting wells in if the storage limit is approached.

The storage of production brine in on-site pits has been prohibited in New York since 1984.

5.16.6 Brine Disposal

Production brine disposal options discussed in the 1992 GEIS include injection wells, treatment plants and road spreading for dust control and de-icing, which are all discussed in the GEIS. If production brine is trucked off-site, it must be hauled by approved Part 364 Waste Transporters.

With respect to road spreading, in January 2009 the Department released a notification to haulers applying for, modifying, or renewing their Part 364 Waste Transporter Permits that any entity applying for a Part 364 permit or permit modification to use production brine for road spreading must submit a petition for a beneficial use determination (BUD) to the Department. The BUD and Part 364 permit must be issued by the Department prior to any production brine being removed from a well site for road spreading. See Appendix 12 for the notification. As discussed in Chapter 7, BUDs for reuse of production brine from Marcellus Shale will not be issued until additional data on NORM content is available and evaluated.

5.16.7 NORM in Marcellus Production Brine

Results of the Department's initial NORM analysis of Marcellus brine produced in New York are shown in Appendix 13. These samples were collected in late 2008 and 2009 from vertical gas wells in the Marcellus formation. The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options, including possible radioactive materials licensing. The NYSDOH will require the well operator to obtain a radioactive materials license for the facility when exposure rate measurements associated with scale accumulation in or on piping, drilling and brine storage equipment exceed 50 microR/hr (µR/hr). A license may be required for facilities that will concentrate NORM during pre-treatment or treatment of brine. Potential impacts and proposed mitigation measures related to NORM are discussed in Chapters 6 and 7.

5.16.8 Gas Gathering and Compression

Operators report a 0.55 psi/foot to 0.60 psi/foot pressure gradient for the Marcellus Shale in the northern tier of Pennsylvania. Bottom-hole pressure equals the true vertical depth of the well times the pressure gradient. Therefore, the bottom-hole pressure on a 6,000-foot deep well will be approximately between 3,300 and 3,600 psi. Wellhead pressures would be lower, depending on the makeup of the gas. One operator reported flowing tubing pressures in Bradford County, Pennsylvania, of 1,100 to 2,000 psi. Gas flowing at these pressures would not initially require compression to flow into a transmission line. Pressure decreases over time, however, and one operator stated an advantage of flowing the wells at as low a pressure as economically practical from the outset, to take advantage of the shale's gas desorption properties. In either case, the necessary compression to allow gas to flow into a large transmission line for sale would typically occur at a centralized site. Dehydration units, to remove water vapor from the gas before it flows into the sales line, would also be located at the centralized compression facilities.

Based on experience in the northern tier of Pennsylvania, operators estimate that a centralized facility will service well pads within a four to six mile radius. The gathering system from the well to a centralized compression facility consists of buried polyvinyl chloride (PVC) or steel pipe, and the buried lines leaving the compression facility consists of coated steel.

Siting of gas gathering and pipeline systems, including the centralized compressor stations described above, is not subject to SEQRA review. See 6 NYCRR 617.5(c)(35). Therefore, the above description of these facilities, and the description in Section 8.1.2.1 of the PSC's environmental review process, is presented for informational purposes only. This SGEIS will not result in SEQRA findings or new SEQRA procedures regarding the siting and approval of gas gathering and pipeline systems or centralized compression facilities. Environmental factors associated with gas-gathering and pipeline systems will be considered as part of the PSC's permitting process.

Photo 5.28 shows an aerial view of a compression facility.

Photo 5.28 - Pipeline Compressor in New York. Source: Fortuna Energy

5.17 Well Plugging

As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continued protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well.

When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.

Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site.

Removal of all surface equipment and full site restoration are required after the well is plugged. Proper disposal of surface equipment includes testing for NORM to determine the appropriate disposal site.

The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review.

New York State

DEC

Chapter 6

Potential Environmental Impacts

Revised Draft
Supplemental Generic Environmental Impact Statement