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. Photo 5.19a 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:[183]

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.

---

[183] 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.

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

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.

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.[184] After the procedure is actually performed, the data gathered can be used to optimize future treatments.[185] 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.[186,187] 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.[188] Comparison of production pressure and flow-rate

---

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

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

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

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

[188] ICF, 2009, p.6.

analysis to pre-fracture modeling is a more common method for evaluating the results of a hydraulic fracturing procedure.[189]

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.[190] 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.[191] In addition, if adjacent rock formations contain water, then fracturing into them would bring water into the reservoir formation and the well. This could result in added costs to handle production brine, or could result in loss of economic hydrocarbon production from the well.[192]

5.8.1 Fracture Development

ICF reviewed how hydraulic fracturing is affected by the rock's natural compressive stresses.[193] 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.[194]

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.[195]

---

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

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

[191] ICF, 2009, p. 14.

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

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

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

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

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.[196]

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.[197] ICF – citing PTTC, 2006 – concludes that: "In the Appalachian Basin, the stress state would be expected to lead to predominantly vertical fractures below about 2500 feet, with a tendency towards horizontal fractures at shallower depths."[198]

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.[199] 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:[200]

- 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.

---

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

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

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

[199] ICF, 2009, p. 16.

[200] ICF, 2009, p. 17.

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. [201]

Photo 5.23 shows personnel monitoring a hydraulic fracturing procedure.

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

---

[201] ICF, 2009, p. 19.

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.[202] 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

---

[202] 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.

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.

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,[203] 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.[204] 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 of water.[205] 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).[206,207] 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.

---

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

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

[205] 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.

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

[207] GWPC, April 2009, p. 59.

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.[208] 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.[209, 210] The first step is typically an acid treatment, which may also involve corrosion inhibitors and iron controls. Acid cleans the 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.[211] 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.[212] 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

---

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

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

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

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

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

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.

Photo 5.25 and Photo 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.

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.[213] 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.[214] 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.[215] 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.

---

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

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

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


1
2
3
4
4
5
6
7
8
9
10
11
12
13
14
15
16
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 5.26 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.

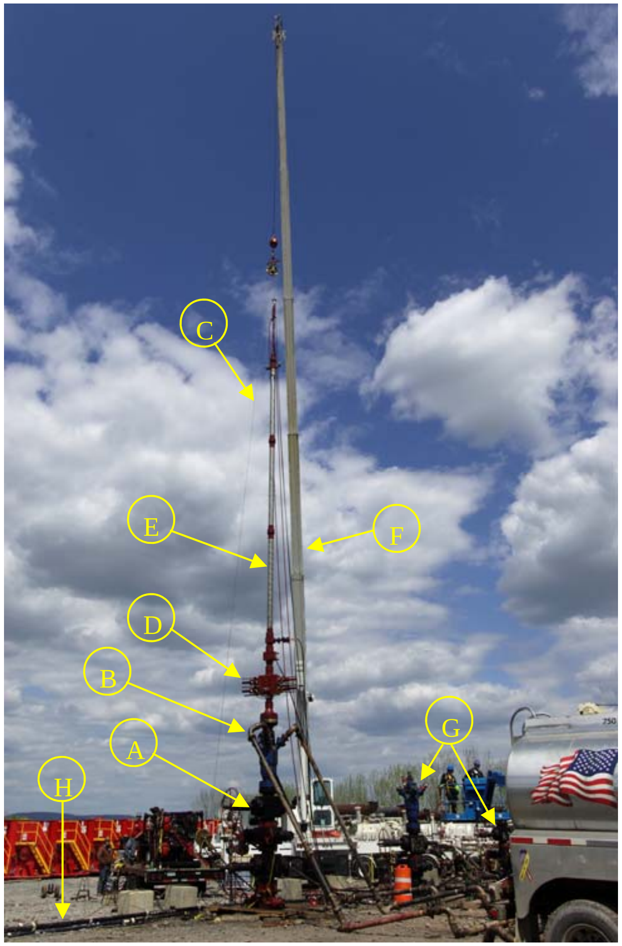


Photo 5.27. Wellhead and Frac Equipment

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)

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.[216] Re-fracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.[217] Changes in formation stresses due to the 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. [218]

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.[219] 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.[220]

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

---

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

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

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

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

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

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 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.[221]

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,[222] 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

---

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

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

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.

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 5.11.3.2.

Table 5.9 - Parameters present in a limited set of flowback analytical results[223] (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

---

[223] 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
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
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

CAS Number	Parameters Detected in Flowback from PA and WV Operations
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
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

CAS Number	Parameters Detected in Flowback from PA and WV Operations
	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
	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[224,225] (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 [226]	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

---

[224] 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.

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

[226] 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.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	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 [227]	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
	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

---

[227] Regulated under beta particles [19].

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	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 [228]	12	12	0.1	0.21	0.61	mg/L
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 [229]	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

---

[228] Regulated under foaming agents.

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

Table 5.11 - Typical concentrations of flowback constituents based on limited samples from PA and WV, not regulated in NY[230](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

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);

---

[230] Table 5-10.

- 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");

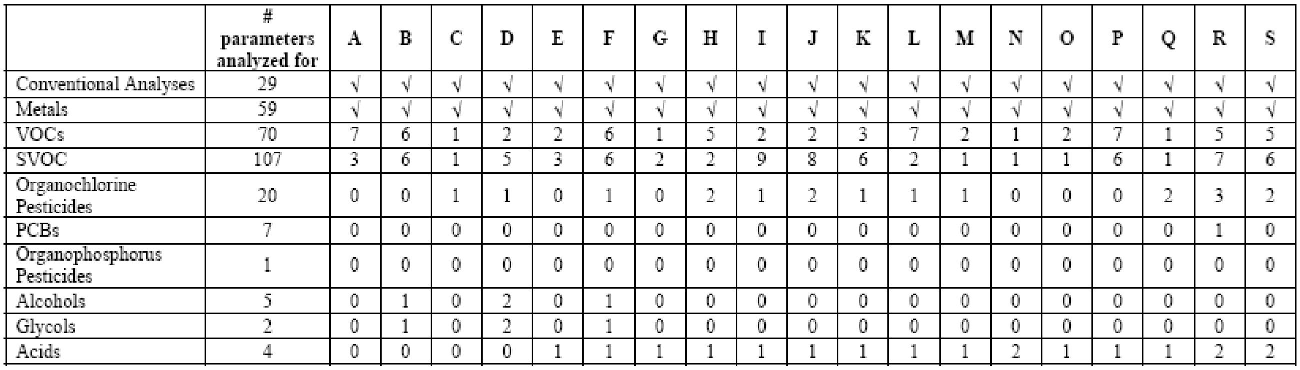
The estimated concentration of the analyte was detected between the method detection limit and the reporting limit. Sample results would be flagged with a laboratory-generated single letter qualifier (i.e., "J"). These results should be considered as estimated concentrations; and

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 Virginia, 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,[231] 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

---

[231] 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.

- Concentrations of metals increase.[232]

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.

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.[233] 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.[234] As stated above,

---

[232] 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.

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

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

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:[235]

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).[236]

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:[237]

Operational

- Flowback fluid characteristics, including scaling and fouling tendencies;
- On-site space availability;

---

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

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

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

- Processing capacity needed;
- Solids concentration in flowback fluid, and solids reduction required;
- Concentrations of hydrocarbons in flowback fluid, and targeted reduction in hydrocarbons;[238]
- 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.

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[239]

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[240]

---

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

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

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 the Barnett Shale and Powder River Basin.[241] 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.[242]

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.[243]

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

---

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

[241] URS 2011, p 5-6.

[242] Yoxtheimer, 2011 (personal communication).

[243] URS 2011, p 5-7.

(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.[244,245] Concentrations of chlorides, calcium, magnesium, barium, carbonates, sulfates, solids and microbes in flowback water may be too high to use as-is, meaning that some form of physical and/or chemical separation is typically needed prior to recycling flowback.[246] In addition, the practice of blending flowback with freshwater involves balancing the additional freshwater water needs with the additional additive needs.[247] 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.[248] 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

---

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

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

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

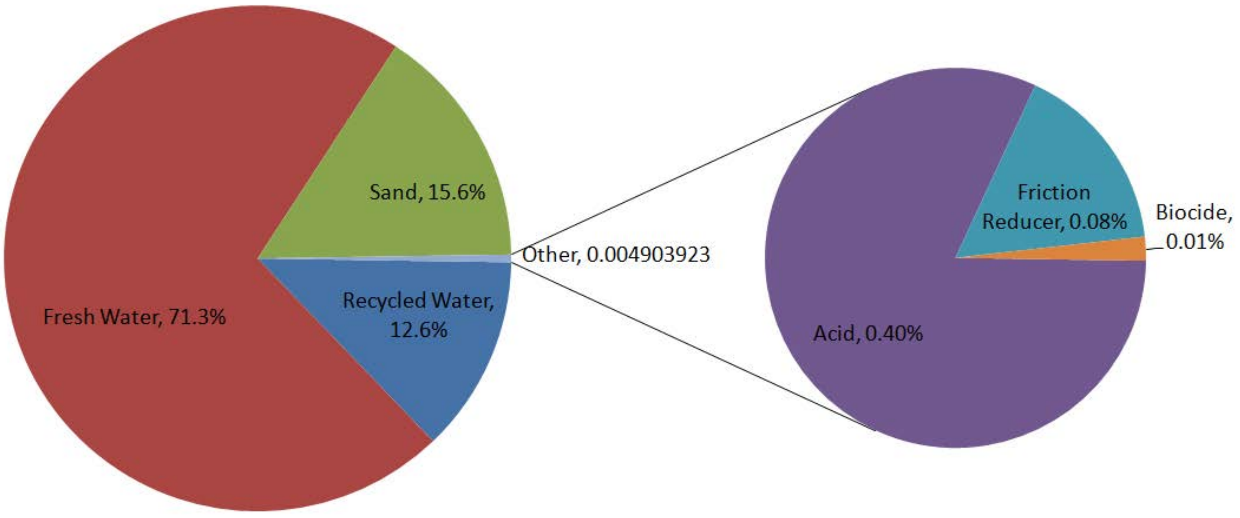
[247] URS, 2009, p. 5-2.

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

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.[249] The current limiting factors on flowback water reuse are the volume of flowback water recovered and the timing of upcoming fracture treatments.[250] 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 for reuse can then be separated for appropriate disposal.[251] 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)



---

[249] SRBC, 2011.

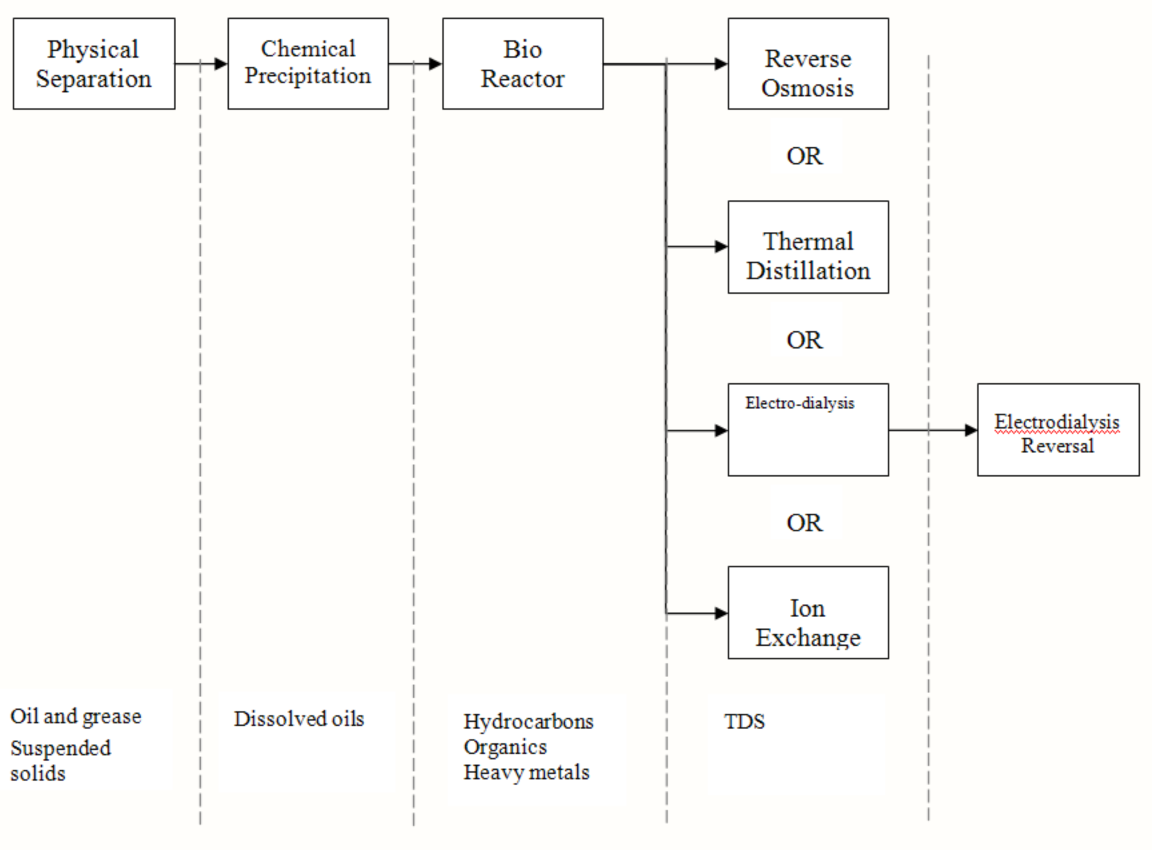
[250] ALL Consulting, 2010, p. 74.

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

5.12.3 Other On-Site Treatment Technologies[252]

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

---

[252] 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, [253] 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.[254]

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

---

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

[254] 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.[255]

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.

---

[255] 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.[256] 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.[257]

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.[258]

---

[256] NETL, 2010.

[257] Yoxtheimer, 2011.

[258] 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 advertised ZLD as a treatment option in the Marcellus, but the economical feasibility of such a system has not yet been demonstrated.[259]

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[260]

---

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

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

Table 5.27 - Summary of Characteristics of On-Site Flowback Water Treatment Technologies (Updated July 2011)[261]

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

---

[261] 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.[262] 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

---

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

testing that require flaring could last for 3 days per well.[263] 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[264]

---

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

[264] 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.[265] 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.[266]

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.

---

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

[266] 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.[267]

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).

---

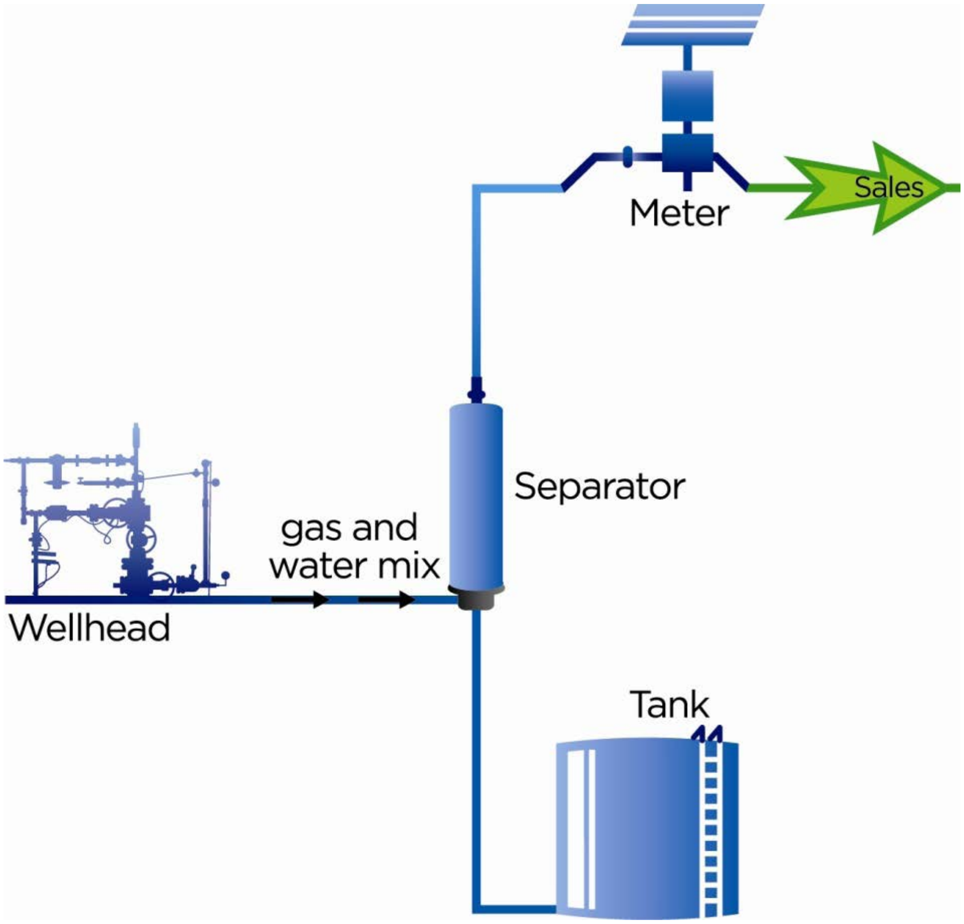
[267] ALL Consulting, 2011, p. 2.

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.