prohibit pits altogether. Some sites have piping along the surface of the well pad or in the shallow subsurface that delivers water used for hydraulic fracturing, removes flowback and produced water, or transports the oil and gas once production begins (Arthur et al., 2009a).

After site and well pad preparation, drill rigs and associated equipment (e.g., the drill rig platform, drilling mud system components, generators, chemical storage tanks, blowout preventer, fuel storage tanks, cement pumps, drill pipe, and casing) are moved on and off the pad at the different stages of well drilling and completion. During drilling and completion, well pads can range in size from less than an acre to several acres depending on the scope of the operations (King, 2012; NYSDEC, 2011).

Well Drilling and Construction

Construction of the production well involves the drilling of the hole (or wellbore), along with the installation and cementing of a series of casing strings to support the wellbore and isolate and protect both the hydrocarbons being produced and any water-bearing zones through which the well passes.[1] In certain settings, some portions of the well can be completed as open holes.[2] Details on these and other well construction activities are presented in Chapter 6 and Appendix D.

The operator begins drilling by lowering and rotating the drill string, which consists of the drill bit, drill pipe (see Figure 2-6), and drill collars (heavy pieces of pipe that add weight to the bit). The drill pipe attaches to the drill bit, rotating and advancing the bit; as drilling advances, new sections of pipe are added at the surface, enabling the drilling to proceed deeper (Hyne, 2012). A drilling fluid is circulated during drilling.[3] The drilling fluid, which may be water-based or oil-based, is pumped down to the drill bit, where it cools and lubricates the drill bit, counterbalances downhole pressures, and lifts the drill cuttings to the surface (King, 2012).

Although all wells are initially drilled vertically, finished well orientations include vertical, deviated, and horizontal. The operator selects the well orientation that will provide access to the targeted zone(s) within a formation and that will align the well with existing fractures and other geologic structures to optimize production. Deviated wells may be “S” shaped or continuously slanted. Horizontal wells have lateral sections oriented approximately 90 degrees from the vertical portion of the well. In wells completed horizontally, the lengths of these laterals can range from 2,000 to 5,000 ft (610 to 1,524 m) or more (Hyne, 2012; Miskimins, 2008; Bosworth et al., 1998).[4] Horizontal wells are instrumental in accessing productive areas of thin and laterally extensive oil- and gas-bearing shales. Although the portion of hydraulically fractured wells that are horizontal is growing, in some areas, such as California, hydraulic fracturing is still primarily conducted in vertical wells (CCST, 2015).

[1] Casing is steel pipe that is lowered into a wellbore. Casing extends from the bottom of the hole to the surface.
[2] An open hole completion is a well completion that has no casing or liner set across the reservoir formation, allowing the produced fluids to flow directly into the wellbore.
[3] Drilling fluid is any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures, and emulsions of liquids, gases, and solids) used when drilling boreholes (Schlumberger, 2014).
[4] A lateral is a horizontal section of a well.

Figure 2-6. Pulling drill pipe onto the drilling platform.

Source: Joshua Doubek, Wikicommons, CC-BY-SA-3.0.

The drilling and well construction proceeds with repeated steps (the drill string is lowered, rotated, drilled to a certain depth, pulled out, and then the casing is lowered into the hole, set, and cemented). Successively smaller diameters of casing are used as the hole is drilled deeper (see Figure 2-7). Selection and installation of the casing strings is important for several purposes, including isolating hydrocarbon reservoirs from nearby aquifers, isolating over-pressured zones, and transporting hydrocarbons to the surface (Hyne, 2012). Newly installed casing strings are cemented in place before drilling continues (or before the well is completed in the instance of the production casing). The cement protects the casing from corrosion by formation fluids, stabilizes the casing and the wellbore, and prevents fluid movement along the well between the outside of the casing and wellbore (Renpu, 2011). The well can be cemented continuously from the surface down to the production zone of the well. Partially cemented wells are also possible with, for example, cement from the surface to some distance below the deepest fresh water-bearing formation and perhaps cement across other deeper formations. Chapter 6 and Appendix D contain more details on casing and cement.

Figure 2-7. Sections of surface casing lined up and being prepared for installation at a well site in Colorado.

Photo credit: Gregory Oberley (U.S. EPA).

When drilling, casing, and cementing are finished, the well can be completed in the production zone in several ways. The production casing may be cemented all the way through the production zone and perforated prior to hydraulic fracturing in the desired locations. Alternatively, operators may use an open hole completion, in which the casing is set just into the production zone and cemented. The remainder of the wellbore within the production zone is left open with no cement (Hyne, 2012). Once all aspects of well construction are completed, the operator can remove the drilling rig, install the wellhead, and prepare the well for stimulation by hydraulic fracturing and subsequent production.

2.1.1. Hydraulic Fracturing

Hydraulic fracturing is typically a short, intense, repetitive process requiring specialized equipment and (for high volume horizontal wells) large amounts of water, chemicals, and proppant. Machinery and equipment are often brought to the site mounted on trucks and remain that way during use. Tanks, totes, and other storage containers of various sizes holding water and chemicals are also transported and installed on site. Figure 2-8 shows a well pad prepared for hydraulic fracturing with the necessary equipment and structures.

Figure 2-8. Hydraulic fracturing operation in Troy, PA.

Site with all equipment on site in preparation for injection. Source: NYSDEC (2011).

2.1.1.2. Injection Process

Prior to injection, hydraulic fracturing fluids are mixed using specialized feeding and mixing equipment. The mixing is generally performed mechanically on a truck-mounted blender and is electronically monitored and controlled by the operator in a separate van (see Chapter 5). Numerous hoses and pipes are used to transfer hydraulic fracturing fluid components from storage units to the mixing equipment and ultimately to the wellhead.

A wellhead assembly is temporarily installed on the wellhead during the fracture treatment to allow high pressures and volumes of proppant-laden fluid to be injected into the well. Pressures required for fracturing can vary widely depending on depth, formation pressure, and rock type. Fracturing pressures have been reported ranging from 4,000 psi to 12,000 psi (Ciezobka and Salehi, 2013; Abou-Sayed et al., 2011; Thompson, 2010). The pressure during fracturing is measured using pressure gauges, which can be installed at the surface and/or downhole (Ross and King, 2007). Figure 2-9 shows two wellheads side-by-side being prepared for fracturing.

Figure 2-9. Two wellheads side-by-side being prepared for hydraulic fracturing at a well site in Pennsylvania.

Photo credit: Mark Seltzer (U.S. EPA).

The entire length of the well in the production zone is not fractured all at once; instead, shorter lengths or segments of the well in the production zone are isolated and fractured in “stages” (Lee et al., 2011). Each stage of a fracturing job can consist of phased injection of different fluids consisting of varying components (i.e., chemicals and additives). These different fluids (1) remove excess drilling fluid or cement from the formation (often using acid) (GWPC and ALL Consulting, 2009), (2) initiate fractures (“pad fluid” without proppant), (3) carry the proppant (Hyne, 2012), and (4) flush the wellbore to ensure that all proppant-laden fluids reach the fractures. Each phase requires moving up to millions of gallons of fluids around the site through various hoses and lines, blending the fluids, and injecting them at high pressures down the well.

The total number of stages depends on the formation properties and the orientation and length of the well. As technology has improved, the lengths of laterals in horizontal wells and the numbers of stages per well have tended to increase (NETL, 2013; Pearson et al., 2013). The number of stages per well can vary, with several sources suggesting that between 10 and 20 is typical (GNB, 2015; Lowe et al., 2013). The full range reported in the literature is much wider, with one source documenting between 1 and 59 stages per well (Pearson et al., 2013) and others reporting values within this range (NETL, 2013; STO, 2013; Allison et al., 2009). For more details on hydraulic fracturing stages, see Chapter 5, Section 5.2.

The induced fractures are designed to achieve the optimum drainage of hydrocarbons from the reservoir formations. Engineers can design fracture systems using modeling software that requires a significant amount of data on formation permeability, porosity, in situ stress, mineralogy, and geologic barrier locations, among other factors (Holditch, 2007). Microseismic monitoring during fracturing can be used to characterize the horizontal and vertical extent of the fractures created and assist with the design of future fracturing jobs (Cipolla et al., 2011). Post-fracture monitoring of pressure or tracers can also help characterize the results of a fracturing job. More details of injection, fracturing, and related monitoring are provided in Chapter 6 and Appendix D.

2.1.1.3. Fracturing Fluids

The fracturing fluids injected into the well serve a variety of purposes and require chemical additives to perform properly (see Chapter 5, Section 5.3). Depending on the geologic setting, reservoir geochemistry, production type, proppant size, and other factors, operators typically choose to use one of several common types of fracturing fluid systems (Arthur et al., 2014; Spellman, 2012; Gupta and Valkó, 2007). Water-based fracturing fluids are the most common, but other fluid types can be used such as: foams or emulsions made with nitrogen, carbon dioxide, or hydrocarbons; acid-based fluids; and others (Montgomery, 2013; Saba et al., 2012; Gupta and Hlidek, 2009; Gupta and Valkó, 2007; Halliburton, 1988). The most common water-based fluid systems are slickwater formulations, which are typically used in very low permeability reservoirs, and gelled fracturing fluids, which can be used in reservoirs with higher permeability (Barati and Liang, 2014).[1,2] More details of hydraulic fracturing fluid systems are discussed in Section 5.3. Importantly, chemical usage in the industry is continually changing as processes are tested and refined by companies. Shifts in fluid formulations are driven by economics, technological developments, and concerns about environmental and health impacts.

[1] Slickwater is a type of fracturing fluid that consists mainly of water with a very low portion of additives like polymers that serve as friction reducers to reduce friction loss when pumping the fracturing fluid downhole (Barati and Liang, 2014).

[2] Gelled fluids are fracturing fluids that are usually water-based with added gels to increase the fluid viscosity to aid in the transport of proppants (Spellman, 2012; Gupta and Valkó, 2007).

The largest constituent of a typical hydraulic fracturing fluid is water (see Figure 2-10). The water sources used for hydraulic fracturing base fluid include ground water, surface water, treated wastewater, and reused flowback or produced water from other wells (URS Corporation, 2011; Blauch, 2010; Kargbo et al., 2010).[1] The water may be brought to the production well site via trucks or piping, or it may be locally sourced (for example, pumped from a local river or obtained from a water well tapping local ground water). Selection of water sources depends upon availability, cost, quality of the water, and the logistics of delivering it to the site. Chapter 4 provides additional details on water acquisition and the amount of water used for hydraulic fracturing.

Figure 2-10. Water tanks (blue, foreground) lined up for hydraulic fracturing at a well site in central Arkansas.

Photo credit: Martha Roberts (U.S. EPA).

Proppants are, by volume, second to the base fluid in the hydraulic fracturing fluid system. Silicate minerals, most notably quartz sand, are the most commonly used proppants. Increasingly, silicate proppants are being coated with resins that help prevent development and flowback of particles or fragments of particles. Ceramic materials, such as those based on calcined (heated) bauxite or calcined kaolin (mullite) are also used as proppants due to their high strength and resistance to crushing and deformation (Beckwith, 2011).

[1] Base fluid is the fluid into which additives and proppants are mixed to formulate a hydraulic fracturing fluid.

Additives comprise relatively small percentages of hydraulic fracturing fluid systems, generally constituting ≤2.0% of the fluid (GWPC and ALL Consulting, 2009). The EPA analyzed additive data in the EPA FracFocus project database 1.0 and estimated that hydraulic fracturing additives in 2011 and 2012 totaled 0.43% of the total amount of fluid injected for hydraulic fracturing (U.S. EPA, 2015a). Note that this small percentage can total tens of thousands of gallons of chemical additives for a typical high-volume hydraulic fracturing job (see Chapter 5, Section 5.4 for details on additive volumes). A given additive may consist of a single chemical ingredient, or it may have multiple ingredients. The mix of chemicals used in any particular fracturing job is influenced by the properties of the target formation, the amount and type of proppant that needs to be carried, operator preference, and to some degree, by local or regional availability of chemicals and potential interactions between chemicals (King, 2012). Chapter 5 includes details on the number, types, and estimated quantities of chemicals that can be used in hydraulic fracturing.

2.1.2. Fluid Recovery, Management, and Disposal

When the injection pressure is reduced at the end of the fracturing process, the direction of fluid flow reverses, with some of the injected hydraulic fracturing fluid flowing into the well and to the surface along with some naturally-occurring fluids from the production zone (NYSDEC, 2011). The fluid is initially a portion of the injected fluid, which decreases over the first few weeks or months until produced water originating from the fractured oil- or gas-bearing rock formation predominates. This recovery of produced water continues over the life of the well (Barbot et al., 2013). Chapter 7 presents descriptions and discussions of the composition and quantities of fluids recovered at the well, referred to as flowback and produced water.

The hydraulic fracturing flowback and produced water (sometimes referred to as hydraulic fracturing wastewater), as well as any other liquid waste from the well pad itself (e.g., rainwater runoff), is typically stored on-site in impoundments (see Figure 2-11) or tanks. This wastewater can be moved offsite via truck or pipelines. The majority of these hydraulic fracturing wastewaters nationally are managed through disposal into deep Class II injection wells regulated under the Underground Injection Control (UIC) program under the Safe Drinking Water Act (see Chapter 8). Other management strategies include treatment followed by discharge to surface water bodies, or reuse for subsequent fracturing operations either with or without treatment (U.S. EPA, 2012f; U.S. GAO, 2012). Decisions regarding wastewater management are driven by factors such as cost (including costs of storage and transportation), availability of facilities for treatment, reuse, or disposal, and regulations (Rassenfoss, 2011). Wastewater management is yet another aspect of fracturing-related oil and gas production that is changing significantly. Chapter 8 contains details of the treatment, reuse and recycling, and disposal of wastewater.

Figure 2-11. Impoundment on the site of a hydraulic fracturing operation in central Arkansas.

Photo credit: Caroline E. Ridley (U.S. EPA).

2.1.3. Oil and Gas Production

After hydraulic fracturing, equipment is removed and partial site reclamation may take place if drilling of additional wells or laterals is not planned (NYSDEC, 2011). Operators may dewater, fill in, and regrade pits that are no longer needed. Parts of the pad may be reseeded, and the well pad may be reduced in size (e.g., from 3 to 5 acres (1 to 2 hectares) during the drilling and fracturing process to 1 to 3 acres (0.4 to 1 hectares) during production) (NYSDEC, 2011).

Wells may be shut-in immediately after completion if there is no infrastructure to receive the product or if prices are unfavorable. Prior to bringing a well into production, the operator typically runs a production test to determine the maximum flow rate the well can sustain and to optimize equipment settings (Hyne, 2012; Schlumberger, 2006). Such tests may be repeated throughout the life of the well. During production, monitoring (e.g., mechanical integrity testing, corrosion monitoring), including any compliance with state monitoring requirements, may be conducted to enable operators to be sure that the well is operating as intended.

In the case of gas wells, the produced gas typically flows through a flowline to a separator that separates the gas from water or any liquid hydrocarbons (NYSDEC, 2011). The finished gas is sent to a compressor station where it is compressed to pipeline pressure and sent to a pipeline for sale. Production at oil wells proceeds similarly, although oil/water or oil/water/gas separation occurs most typically on the well pad, no compressor is needed, and the oil can be hauled (by truck or train) or piped from the well pad.

During the life of the well it may be necessary to perform workovers to maintain or repair portions or components of the well and replace old equipment. Such workovers involve ceasing production and removing the wellhead, and may include cleaning out sand or deposits from the well, repairing casing, replacing worn well components such as tubing or packers, or installing or replacing lift equipment to pump hydrocarbons to the surface (Hyne, 2012). In some cases, wells may be recompleted after the initial construction, with re-fracturing if production has decreased (Vincent, 2011). Recompletion also may include additional perforations in the well at a different interval to produce from a different formation than originally done, lengthening the wellbore, or drilling new laterals from an existing wellbore.

As of 2012, Shires and Lev-On (2012) suggested that the rate of re-fracturing in natural gas wells was about 1.6%. Analysis for the EPA's 2012 Oil and Gas Sector New Source Performance Standards indicated a re-fracture rate of 1% for gas wells (U.S. EPA, 2012d). In the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks (U.S. EPA, 2015g), the number of gas wells that were re-fractured in a given year as a percent of the total existing population of hydraulically fractured producing gas wells in a given year ranges from 0.3% to 1% across the 1990-2013 period.

2.1.1.4. Production Rates and Duration

The production life of a well depends on a number of factors, such as the amount of hydrocarbons in place, the reservoir pressure, production rate, and the economics of well operations. It may be as short as three or four years in deep-water, high-permeability formations and as long as 40 to 60 years in onshore tight gas reservoirs (Ross and King, 2007). In hydraulically fractured wells in unconventional reservoirs, production is often characterized by a rapid drop followed by a slower decline compared to conventional hydrocarbon production wells (Patzek et al., 2013). However, most modern, high-volume fractured wells are less than a decade old. Consequently, there is a limited historical basis to determine the full extent of the production decline (Patzek et al., 2013) and to ultimately determine how much they will produce.

2.1.4. Site and Well Closure

Once a well reaches the end of its useful life, it is plugged, and the well site is closed. If a wellbore is not properly plugged, fluids from higher pressure zones may eventually migrate through the wellbore to the surface or to other zones such as fresh water aquifers (NPC, 2011b). Plugging is usually performed according to state regulations governing the locations and materials for plugs (Calvert and Smith, 1994). Operators typically use cement plugs placed across fresh water formations and oil or gas formations (NPC, 2011b). Some surface structures can be left in place, and the local topography and land cover are restored to predevelopment conditions to the extent possible, per state regulations. The wellhead and any surface equipment are removed. Impoundments are dewatered, filled in, and graded. The well casing is typically cut off below the surface and a steel plate or cap is emplaced to seal the top of the casing and wellbore (API, 2010a), although there may also be an aboveground marker used in some locations. Some states require notification of the landowner or a government agency of the location of the well.