Chapter 6

Well Injection

6. Well Injection

6.1. Introduction

To conduct hydraulic fracturing, fluids (primarily water, mixed with the types of chemicals and proppant described in Chapter 5) are injected into a well under high pressure.[1] These fluids flow under pressure through the well (sometimes thousands of feet below the surface), then exit the well and move into the formation, where they create fractures in the rock. This process is also known as a fracture treatment or a type of stimulation.[2] The fractures, which typically extend hundreds of feet laterally from the well, are designed to remain within the production zone to access as much oil or gas as possible, while using no more water or chemicals than necessary to complete the operation.[3]

Production wells are sited and designed primarily to optimize production of oil or gas, which requires isolating water-bearing formations and those containing the hydrocarbons to be exploited from each other. This isolation can also protect drinking water resources. Appropriately sited, designed, constructed, and operated wells and hydraulic fracturing treatments can reduce the potential for impacts to drinking water resources. However, problems with the well's components or improperly sited, designed, or executed hydraulic fracturing operations (or combinations of these) could lead to adverse effects on drinking water resources.

The well and the geologic environment in which it is located are a closely linked system, often designed with multiple barriers (i.e., isolation afforded by the well's casing and cement and the presence of multiple layers of subsurface rock) to prevent fluid movement between oil/gas zones and drinking water resources. Therefore, in this chapter we discuss (1) the well (including its construction and operation) and (2) features in the subsurface geologic formations that could provide or have provided pathways for migration of fluids to drinking water resources. If present and in combination with the existence of a fluid and a physical force that moves the fluid, these pathways can lead to impacts on drinking water resources throughout the life of the well, including during and after hydraulic fracturing.[4]

Fluids can move **via pathways adjacent to or through the production well** that are created in response to the stresses exerted during hydraulic fracturing operations (see Section 6.2). While wells are designed and constructed to isolate fluids and maximize the production of oil and gas,

[1] A fluid is a substance that flows when exposed to an external pressure; fluids include both liquids and gases.
[2] In the oil and gas industry, "stimulation" has two meanings—it refers to (1) injecting fluids to clear the well or pore spaces near the well of drilling mud or other materials that create blockage and inhibit optimal production (i.e., matrix treatment) and (2) injecting fluid to fracture the rock to optimize the production of oil or gas. This chapter focuses on the latter.
[3] The "production zone" (sometimes referred to as the target zone) refers to the portion of a subsurface rock zone that contains oil or gas to be extracted (sometimes using hydraulic fracturing). "Producing formation" refers to the larger geologic unit in which the production zone occurs.
[4] The primary physical force that moves fluids within the subsurface is a difference in pressure. Fluids move from areas of higher pressure to areas of lower pressure when a pathway exists. Density-driven buoyancy may also serve as a driving force. See Section 6.3.

inadequate construction or degradation of the casing or cement can allow fluid movement that can change the quality of drinking water resources. Potential issues associated with wells may be related to the following:

- Casing (e.g., faulty, inadequate, or degraded casing or other well components, as influenced by the numbers of casings; the depths to which these casings are set; compatibility with the geochemistry of intersected formations; the age of the well; whether re-fracturing is performed; and other operational factors) and
- Cement (e.g., poor, inadequate, or degraded cement, as influenced by a lack of cement in key intervals; poor-quality cement; improper or inadequate placement of cement; or degradation of cement over time).

Fluid movement can also occur **via induced fractures and/or other features within subsurface formations** (see Section 6.3). While the hydraulic fracturing operation may be designed so that the fractures will remain within the production zone, it is possible that, in the execution of the hydraulic fracturing treatment, fractures can extend beyond their designed extent. Four scenarios associated with induced fractures may contribute to fluid migration or communication between zones:

- Flow of injected and/or displaced fluids through pore spaces in the rock formations out of the production zone due to pressure differences and buoyancy effects.
- Fractures extending out of oil/gas formations into drinking water resources or zones that are in communication with drinking water resources or fracturing into zones containing drinking water resources.
- Fractures intersecting artificial structures, including abandoned or active (producing) offset wells near the well that is being stimulated (i.e., well communication) or abandoned or active mines.[1]
- Fractures intersecting geologic features that can act as conduits, such as existing permeable faults and fractures.

In this chapter, we describe the conditions that can contribute to or cause the development of the pathways listed above, the evidence for the existence of these pathways, and potential impacts or impacts on drinking water resources associated with these pathways.

The interplay between the well and the subsurface features is complex, and sometimes it is not possible to identify what specific element is contributing to or is the primary cause of an impact to drinking water resources. For example, concerns have been raised regarding stray gas detected in ground water in natural gas production areas (for additional information about stray gas, see Sections 6.2.2 and 6.3.2.4).[2] Stray gas migration is a technically complex phenomenon, because

[1] An abandoned well refers to a well that is no longer being used or cannot be used because of its poor condition.
[2] Stray gas refers to the phenomenon of natural gas (primarily methane) migrating into shallow drinking water resources or to the surface.

there are many potential naturally occurring or artificially created routes for migration of gas into aquifers (including along production wells and via naturally existing or induced fractures), and it is challenging to determine the source of the natural gas and whether the mobilization is related to oil or gas production activities.

Furthermore, identifying cases where contamination of drinking water resources occurs due to oil and gas production activities—including hydraulic fracturing operations—requires extensive amounts of site and operational data, collected before and after hydraulic fracturing operations. Where such data does exist and provides evidence of contamination, we present it in the following sections. We do not attempt to predict which of these pathways is most likely to occur or to lead to a drinking water impact, or the magnitude of an impact that might occur as a result of migration via any single pathway, unless the information is available and documented based on collected data.

6.2. Fluid Migration Pathways Within and Along the Production Well

In this section, we discuss pathways for fluid movement along or through the production well used in the hydraulic fracturing operation. While these pathways can form at any time within any well, the repeated high pressure stresses exerted during hydraulic fracturing operations may make maintaining integrity of the well more difficult (Council of Canadian Academies, 2014). In Section 6.2.1, we present the purpose of the various well components and typical well construction configurations. Section 6.2.2 describes the pathways for fluid movement that can potentially develop within the production well and wellbore and the conditions that lead to pathway development, either as a result of the original design of the well, degradation over time or use, or hydraulic fracturing operations.

While we discuss casing and cement separately, it is important to note that these are related—inadequacies in one of these components can lead to stresses on the other. For example, flaws in cement may expose the casing to corrosive fluids. Furthermore, casing and cement work together in the subsurface to form a barrier to fluid movement, and it may not be possible to distinguish whether integrity problems are related to the casing, the cement, or both. For additional information on well design and construction, see Appendix D.

6.2.1. Overview of Well Construction

Production wells are constructed to convey hydrocarbon resources from the reservoirs in which they are found to the surface and also to isolate fluid-bearing zones (containing oil, gas, or fresh water) from each other. Multiple barriers are often present, and they act together to prevent both horizontal movement (in or out of the well) and vertical movement (along the wellbore from deep formations to drinking water resources). Proper design and construction of the casing, cement, and other well components in the context of the location of drinking water resources and maintaining mechanical integrity throughout the life of a well are necessary to prevent migration of fracturing fluids, formation fluids, and hydrocarbons into drinking water resources.

A well is a multiple-component system that typically includes casing, cement, and a completion assembly, and it may be drilled vertically, horizontally, or in a deviated orientation.[1] These components work together to prevent unintended fluid movement into, out of, or along the well. Due to the presence of multiple barriers within the well and the geologic system in which it is placed, the existence of one pathway for fluid movement does not necessarily mean that an impact to a drinking water resource has occurred or will occur.

Casing primarily acts as a barrier to lateral movement of fluids, and cement primarily acts as a barrier to unintended vertical movement of fluids. Together, casing and cement are important in preventing fluid movement into drinking water resources, and are the focus of this section. Figure 6-1 illustrates the configurations of casing and cement that may occur in oil and gas production wells, including the types of casing strings that may be present, the potential locations of cement, and other features. The figure depicts an idealized representation of the components of a production well; it is important to note that there is a wide variety in the design of hydraulically fractured oil and gas wells in the United States (U.S. EPA, 2015o), and the descriptions in the figure or in this chapter do not represent every possible well design.

6.2.1.1. Casing

Casing is steel pipe that is placed into the drilled wellbore to maintain the stability of the wellbore, to transport the hydrocarbons from the subsurface to the surface, and to prevent intrusion of other fluids into the well and wellbore (Hyne, 2012; Renpu, 2011). A long continuous section of casing is referred to as a casing string, which is composed of individual lengths of casing (known as casing joints) that are threaded together using casing collars. In different sections of the well, multiple concentric casing strings (of different diameters) can be used, depending on the construction of the well.

The presence of multiple layers of casing strings can isolate and protect geologic zones containing drinking water. In addition to conductor casing, which prevents the hole from collapsing during drilling, one to three other types of casing may be also present in a well. The types of casing include (from largest to smallest diameter) surface casing, intermediate casing, and production casing (GWPC, 2014; Hyne, 2012; Renpu, 2011). One or more of any of these types of casing may be present in a well. Surface casing often extends from the wellhead down to the base (bottom) of the drinking water resource to be protected. Wells also may be constructed with liners, which are anchored or suspended from inside the bottom of the previous casing string, rather than extending all the way to the surface, and production tubing, which is used to transport the hydrocarbons to the surface.

[1] For the purposes of this assessment, a well's "orientation" refers to the direction in which the well is drilled, and "deviation" is used to indicate an orientation that is neither strictly vertical nor strictly horizontal. However, in industry usage, "deviation" is also used as a generic term to indicate well orientation.

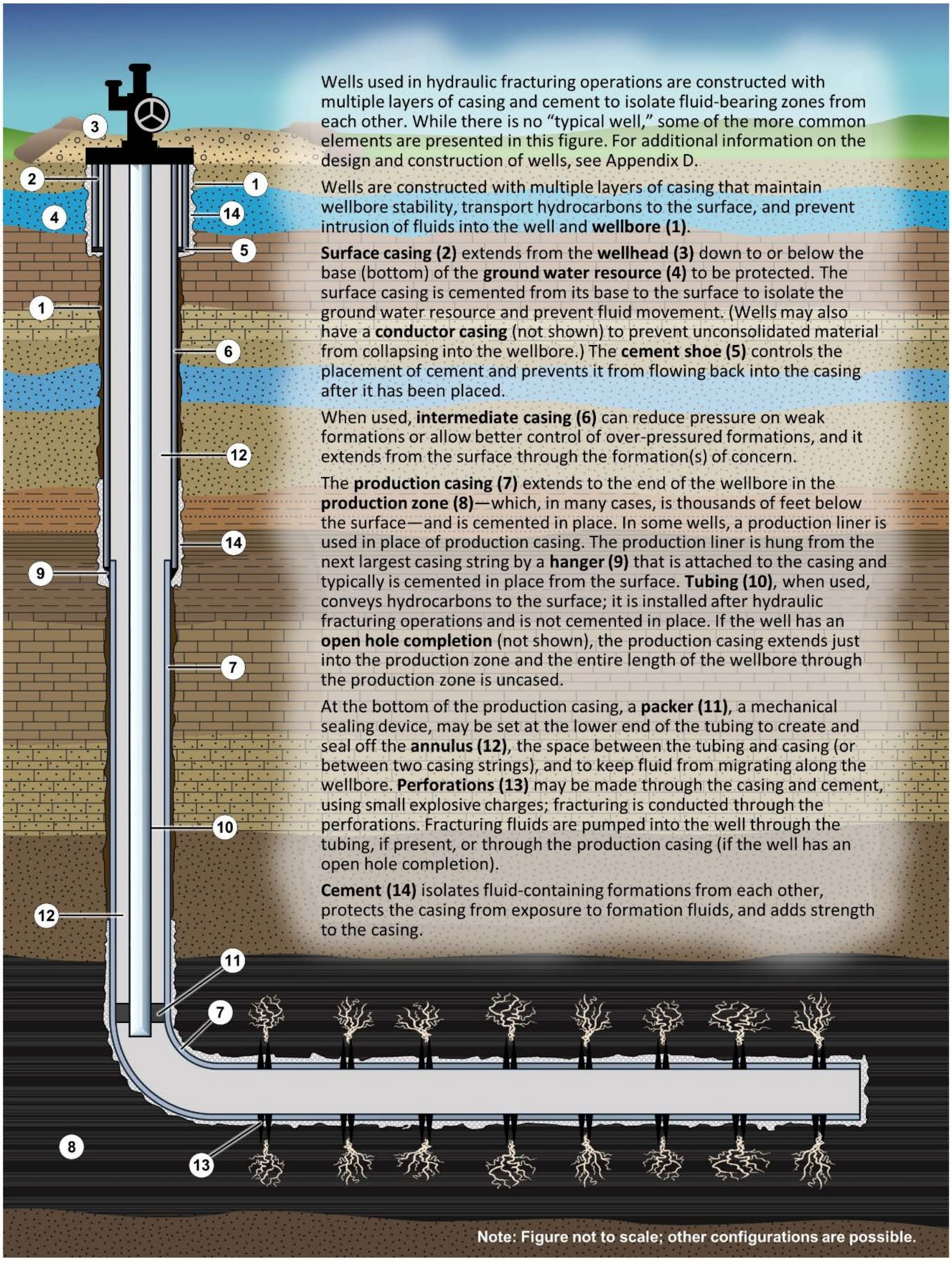

Figure 6-1. Overview of well construction.

Among the wells represented by the Well File Review (see Text Box 6-1), between one and three casing strings were present (the Well File Review did not evaluate conductor casings). A combination of surface and production casings was most often reported, followed by a combination of surface, intermediate, and production strings. All of the production wells used in hydraulic fracturing operations in the Well File Review had surface casing, while approximately 39% of the wells (an estimated 9,100 wells) had intermediate casing, and 94% (an estimated 21,900 wells) had production casing (U.S. EPA, 2015o).

Text Box 6-1. The Well File Review.

The EPA conducted a survey of onshore oil and gas production wells that were hydraulically fractured by nine oil and gas service companies in the continental United States between approximately September 2009 and September 2010. The *Review of Well Operator Files for Hydraulically Fractured Oil and Gas Production Wells: Well Design and Construction* (U.S. EPA, 2015o), referred to as the Well File Review, presents the results of the survey and describes, for these wells: well design and construction characteristics, the relationship of well design and construction characteristics to drinking water resources, and the number and relative location of well construction barriers (i.e., casing and cement) that can block pathways for potential subsurface fluid movement.

The results of the survey are based on information provided by well operators for a statistically representative sample of 323 hydraulically fractured oil and gas production wells. The EPA did not attempt to independently and systematically verify data supplied by well operators. Consequently, results from analyses based on these data are of the same quality as the supplied data.

Results of the survey are presented as rounded estimates of the frequency of occurrence of hydraulically fractured production well design or construction characteristics with 95% confidence intervals. The results are statistically representative of an estimated 23,200 (95% confidence interval: 21,400-25,000) onshore oil and gas production wells hydraulically fractured in 2009 and 2010 by the nine service companies.

Hydraulic fracturing operations impose a variety of stresses on the well components. The casing should be designed with sufficient strength to withstand the stresses it will encounter during the installation, cementing, fracturing, production, and postproduction phases of the life of the well. These stresses, illustrated in Figure 6-2, include burst pressure (the interior pipe pressure that will cause the casing to burst), collapse pressure (the pressure applied to the outside of the casing that will cause it to collapse), tensile stress (the stress related to stretching exerted by the weight of the casing or tubing being raised or lowered in the hole), compression and bending (the stresses that result from pushing along the axis of the casing or bending the casing), and cyclical stress (the stress caused by frequent or rapid changes in temperature or pressure). Casing strength can be increased by using high-strength alloys or by increasing the thickness of the casing. In addition, the casing must be resistant to corrosion from contact with the formations and any fluids that might be transported through the casing, including hydraulic fracturing fluids, brines, and oil or gas.

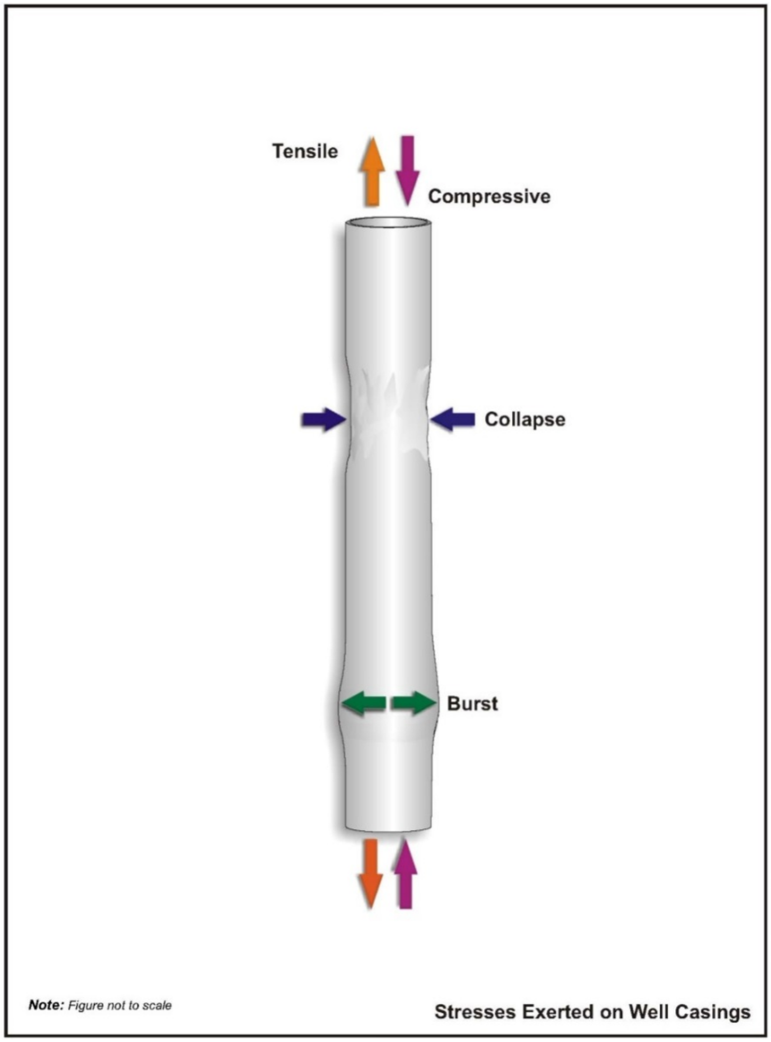

Figure 6-2. The various stresses to which the casing will be exposed.

In addition to the stresses illustrated, the casing will be subjected to bending and cyclical stresses. Source: U.S. EPA (2012c).

6.2.1.2. Cement

Cement is one of the most important components of a well for providing zonal isolation and reducing impacts on drinking water. Cement isolates fluid-containing formations from each other, protects the casing from exposure to formation fluids, and provides additional strength to the casing. The strength of the cement and its compatibility with the formations and fluids encountered are important for maintaining well integrity through the life of the well.

The cement does not always need to be continuous along the entire length of the well in order to protect drinking water resources; rather, protection of drinking water resources depends on a good cement seal across the appropriate subsurface zones, including all fresh water- and hydrocarbon-bearing zones. One study in the Gulf of Mexico found that there was no breakdown in isolation between geologic zones with pressure differentials as high as 14,000 psi as long as there was at least 50 ft (15 m) of high-quality cement between the zones (King and King, 2013).

Most wells have cement behind the surface casing, which is a key barrier to contamination of drinking water resources. The surface casings in nearly all of the wells used in hydraulic fracturing operations represented in the Well File Review (93% of the wells, or an estimated 21,500 wells) were fully cemented.[1] None of the wells studied in the Well File Review had completely uncemented surface casings.

The length and location of cement behind intermediate and production casings can vary based on the presence and locations of over-pressured formations, formations containing fluids, or geologically weak formations (i.e., those that are prone to structural failure when exposed to changes in subsurface stresses). State regulations and economics also play a role; 25 out of 27 oil and gas producing states surveyed by the Ground Water Protection Council require some minimum amount of cementing on the production casing above the producing zone (GWPC, 2014). In general, the intermediate casings of the wells studied in the Well File Review were fully cemented; while among production casings, about half were partially cemented, about a third were fully cemented, and the remainder were either uncemented or their cementing status was undetermined. Among the approximately 9,100 wells represented in the Well File Review that are estimated to have intermediate casing, the intermediate casing was fully cemented in an estimated approximately 7,300 wells (80%) and partially cemented in an estimated 1,700 wells (19%). Production casings were partially cemented in 47% of the wells, or approximately 10,900 wells (U.S. EPA, 2015o).

The Well File Review also estimated the number of wells with a continuous cement sheath along the outside of the well. An estimated 6,800 of the wells represented in the study (29%) had cement from the bottom of the well to the ground surface, and approximately 15,300 wells (66%) had one or more uncemented intervals between the bottom of the well and the ground surface. In the remaining wells, the location of the top of the cement was uncertain, so no determination could be made regarding whether the well had a continuous cement sheath along the outside of the well (U.S. EPA, 2015o).

A variety of methods are available for placing the cement, evaluating the adequacy of the cementing process and the resulting cement job, and repairing any identified deficiencies. Cement is most commonly emplaced by pumping the cement down the inside of the casing to the bottom of the wellbore and then up the space between the outside of the casing and the formation (or the next largest casing string). This method is referred to as the primary cement job and can be performed as a continuous event in a single stage (i.e., "continuous cementing") or in multiple stages (i.e., "staged cementing"). Staged cementing may be used when, for example, the estimated weight and

[1] The Well File Review defined fully cemented casings as casings that had a continuous cement sheath from the bottom of the casing to at least the next larger and overlying casing (or the ground surface, if surface casing). Partially cemented casings were defined as casings that had some portion of the casing that was cemented from the bottom of the casing to at least the next larger and overlying casing (or ground surface), but were not fully cemented. Casings with no cement anywhere along the casing, from the bottom of the casing to at least the next larger and overlying casing (or ground surface), were defined as uncemented.

pressure associated with standard cement placement could damage weak zones in the formation (Crook, 2008).

Deficiencies in the cementing process can result from poor centering or lost cement.[1] Poor centering of the casing within the wellbore can cause uneven cement placement around the wellbore, leading to the formation of thin weak spots that are prone to creation of uncemented channels around the casing and loss of integrity (Kirksey, 2013). If any deficiencies or defects in the primary cement job are identified, remedial cementing may be performed.

In over 90% of wells studied in the Well File Review, the casing strings were cemented using primary cement methods. Secondary or remedial cementing was used on an estimated 4,500 casings (8%) most often on surface and production casings and less often on intermediate casings. The remedial cementing techniques employed in these wells included cement squeezes, cement baskets, and pumping cement down the annulus (U.S. EPA, 2015o). See Appendix D for more information on remedial cementing techniques.

A variety of logs are available to evaluate the quality of cement behind the well casing. Among wells in the Well File Review, the most common type of cement evaluation log run was a standard acoustic cement bond log (U.S. EPA, 2015o). Standard acoustic cement bond logs are used to evaluate both the extent of the cement placed along the casing and the cement bond between the cement, casing, and wellbore.[2] Cement bond indices calculated from standard acoustic cement bond logs on the wells in the Well File Review showed a median bond index of 0.7 just above the hydraulic fracturing zone; this value decreased to 0.4 over a measured distance of 5,000 ft (1,524 m) above the hydraulic fracturing zone (U.S. EPA, 2015o). While standard acoustic cement bond logs can give an average estimate of bonding, they cannot alone indicate zonal isolation, because they may not be properly run or calibrated (Boyd et al., 2006; Smolen, 2006). One study of 28 wells found that cement bond logs failed to predict communication between formations 11% of the time (Boyd et al., 2006). In addition, they cannot discriminate between full circumferential cement coverage by weaker cement and lack of circumferential coverage by stronger cement (King and King, 2013; Smolen, 2006). A few studies have compared cement bond indices to zonal isolation, with varying results. For example, Brown et al. (1970) showed that among 16 South American wells with varying casing size and cement bond indices, a cemented 5.5 in (14 cm) diameter casing with a bond index of 0.8 along as little as five feet can act as an effective seal. The authors also suggest that an effective seal in wells having calculated bond indices differing from 0.8 are expected to have an inverse relationship between bond index and requisite length of cemented interval, with longer lengths needed along casing having a lower bond index. Another study recommends that wells undergoing hydraulic fracturing should have a given cement bond over an interval that is three times the length that would otherwise be considered adequate for zonal isolation (Fitzgerald et al.,

[1] Lost cement refers to a failure of the cement or the spacer fluid used to wash the drilling fluid out of the wellbore to be circulated back to the surface, indicating that the cement has escaped into the formation.
[2] Cement bond logs are used to calculate a bond index, which varies between 0 and 1, with 1 representing the strongest bond and 0 representing the weakest bond.

1985). Conversely, King and King (2013) concluded that field tests from wells studied by Flournoy and Feaster (1963) had effective isolation when the cement bond index ranged from 0.31 to 0.75.

6.2.1.3. Well Orientation

A well can be drilled and constructed with any of several different orientations: vertical, horizontal, and deviated. The well's orientation can be important, because it affects the difficulty of drilling, constructing, and cementing the well. In particular, as described below, constructing and cementing horizontal wells present unique challenges (Sabins, 1990). In a vertical well, the wellbore is vertical throughout its entire length, from the wellhead at the surface to the production zone. Deviated wells are drilled vertically but are designed to deviate from the vertical direction at some point such that the bottom of the well is at a significant lateral distance away from the point in the subsurface directly under the wellhead. In a horizontal well, the well is drilled vertically to a point known as the kickoff point, where the well turns toward the horizontal, extending into and parallel with the approximately horizontal targeted producing formation (see Figure 6-1).

The use of horizontal wells, particularly in unconventional reservoirs, is increasing (DrillingInfo, 2014b; Valko, 2009). Among wells evaluated in the Well File Review (i.e., over the period of September 2009 to September 2010), about 66% were vertical, 11% were horizontal, and about 23% were deviated wells (U.S. EPA, 2015o).[1] This is generally consistent with information available in industry databases—of the approximately 16,000 oil and gas wells used in hydraulic fracturing operations in 2009 (one of the years for which the data for the Well File Review were collected), 39% were vertical, 33% were horizontal, and 28% were either deviated or the orientation was unknown (DrillingInfo, 2014b). Note that among natural gas wells used in hydraulic fracturing operations, 49.5% of wells in the DrillingInfo database were horizontal. The use of horizontal wells in hydraulic fracturing operations has also been steadily increasing; in 2012, 63.7% of all wells used in hydraulic fracturing operations were horizontal, compared to just 4% in 2003 (DrillingInfo, 2014b). See Figure 2-16 for a map presenting the locations of horizontal wells in the United States.

6.2.1.4. Well Completion

Another important aspect of well construction is how the well is completed into the production zone, because the well's completion is part of the system of barriers and must be intact to provide a fully functioning system.[2] A variety of completion configurations are available. The most common configuration is for casing to extend to the end of the wellbore and be cemented in place (U.S. EPA, 2015o; George et al., 2011; Renpu, 2011). Before hydraulic fracturing begins, perforations are made through the casing and cement into the production zone. It is through the perforated casing and cement that hydraulic fracturing is conducted. In some cases, a smaller temporary casing, known as a frac string, is inserted inside the production casing to protect it from the high pressures imposed during hydraulic fracturing operations. Another method of completion is an open hole completion,

[1] The Well File Review considered any non-horizontal well in which the well bottom was located more than 500 ft (152 m) laterally from the wellhead as being deviated.

[2] Completion is a term used to describe the assembly of equipment at the bottom of the well that is needed to enable production from an oil or gas well. It can also refer to the activities and methods (including hydraulic fracturing) used to prepare a well for production following drilling.

where the production casing extends into the production zone and the entire length of the drilled horizontal wellbore through the production zone is left uncased. With open hole completions, the entire production zone can either be fractured all at once in a single stage, or in stages using a casing string set on formation packers, which separate the annulus into stages.[1] A special casing with retractable sleeves is used to fracture each stage separately. Among wells represented in the Well File Review, an estimated 6% of wells (1,500 wells) had open hole completions, 6% of wells (1,500 wells) used formation packers, and the rest were cased and cemented (U.S. EPA, 2015o).

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 new formation, lengthening the wellbore, or drilling new laterals from an existing wellbore.

6.2.2. Evidence of the Existence of Fluid Movement Pathways or of Fluid Movement

The following sections describe the pathways for fluid movement that can develop within the production well and wellbore. We also describe the conditions that lead to the development of fluid movement pathways and, where available, evidence that a pathway has allowed fluid movement to occur within the casing or cement, and—in the case of sustained casing pressure (see Section 6.2.3)—a combination of factors within the casing and cement. (See Figure 6-3 for an illustration of potential fluid movement pathways related to casing and cement.) We describe available information regarding the rate at which these pathways have been identified in hydraulic fracturing wells or, where such information does not exist, present the results of research on oil and gas production wells in general or on injection wells.[2] Insufficient publicly accessible information exists to determine whether wells intended for hydraulic fracturing are constructed differently from production wells where no fracturing is conducted. However, given the applicability of well construction technology to address the subsurface conditions encountered in hydraulic fracturing operations and production or injection operations in general, this information is considered relevant to the research questions (see Section 6.4).

While new wells can be specifically designed to withstand the stresses associated with hydraulic fracturing operations, older wells, which are sometimes used in hydraulic fracturing operations, may not have been designed to the same specifications. Where older wells were not designed specifically to withstand the stresses associated with hydraulic fracturing, their reuse for this purpose could be a concern. Frac strings, which are specialized pieces of casing inserted inside the production casing, may be used to protect older casing during fracturing. However, the effect of fracturing on the cement on the production casing in older wells is unknown. One study on re-fracturing of wells noted that the mechanical integrity of the well was a key factor in determining the success or failure of the fracturing (Vincent, 2011). An estimated 6% of wells (1,400 wells)

[1] A formation packer is a specialized casing part that has the same inner diameter as the casing but whose outer diameter expands to make contact with the formation and seal the annulus between the casing and formation, preventing migration of fluids.
[2] An injection well is a well into which fluids are being injected (40 CFR 144.3).

represented in the Well File Review were more than 10 years old before they were fractured between 2009 and 2010 (U.S. EPA, 2015o).

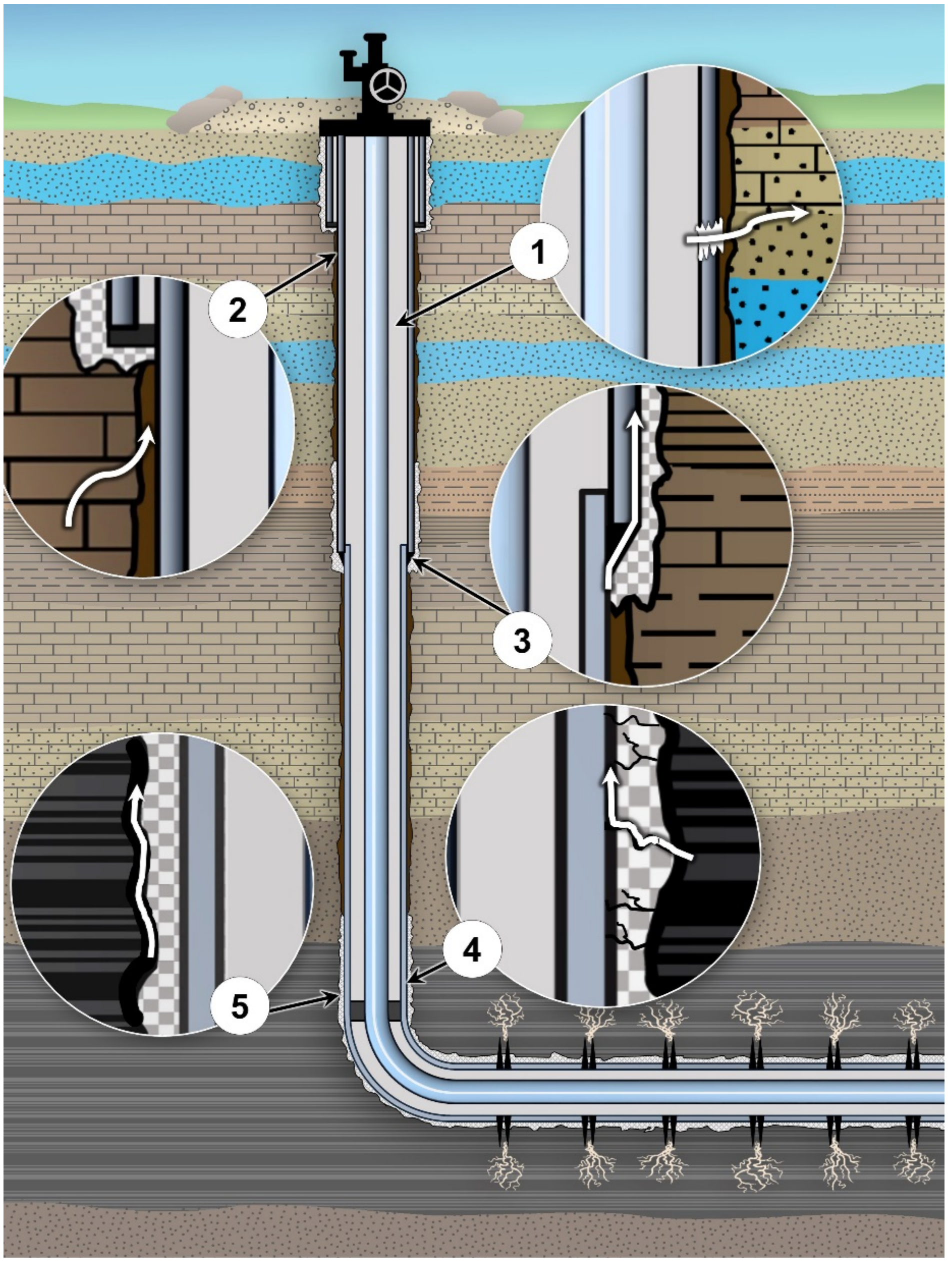

Figure 6-3. Potential pathways for fluid movement in a cemented wellbore.

These pathways include: (1) casing/tubing leak into a permeable formation, (2) migration along an uncemented annulus, (3) migration along microannuli between the casing and cement, (4) migration through poor cement, or (5) migration along microannuli between the cement and formation. Note: the figure is not to scale and is intended to provide a conceptual illustration of pathways that may develop within the well.

Note that there are also potential issues related to *where* older wells are sited. For example, some wells may be in areas with naturally occurring subsurface faults or fractures that could not be detected or fully characterized with the technologies available at the time of construction. See Section 6.3.2.

6.2.2.1. Pathways Related to Well Casing

High pressures associated with hydraulic fracturing operations can damage the casing and lead to fluid movement that can change the quality of drinking water resources. The casing string through which fracturing fluids are injected is subject to higher pressures during fracturing operations than during other phases in the life of a production well. To withstand the stresses created by the high pressure of hydraulic fracturing, the well and its components must have adequate strength and elasticity. If the casing is compromised or is otherwise not strong enough to withstand these stresses (see Figure 6-2), a casing failure may result. If undetected or not repaired, casing failures will serve as pathways for fracturing fluids to leak out of the casing.[1] Below we present indicators that pathways along the casing are present or allowing fluid movement.

Fracturing fluids or fluids naturally present in the subsurface could flow into other zones in the subsurface if inadequate or no cement is present and the pressure in the casing is greater than the formation pressure. As we describe below, pathways for fluid movement associated with well casing may be related to the original design or construction of the well, degradation of the casing over time, or problems that can arise through extended use as the casing succumbs to stresses.

Casing failure may also occur if the wellbore passes through a structurally weak geologic zone that fails and deforms the well casing. Such failures are common when drilling through zones containing salt (Renpu, 2011). This type of well damage may also be possible if hydraulic fracturing causes stress failure along a fault. Investigation of a well following a seismic event in England that was attributed to hydraulic fracturing found that the casing had been deformed by the stress from the formation (De Pater and Baisch, 2011). While it is not known if the casing deformation occurred before or after the seismic event, such damage is possible if mechanically weak formations are present. The changes in the pressure field in the portions of the formation near the wellbore during hydraulic fracturing can also cause mechanically weak formations to fail, potentially damaging the well. Palmer et al. (2005) demonstrated through modeling that hydraulic fracturing within coal that had a low unconfined compressive strength could cause shear failure of the coalbeds surrounding the wellbore.

Corrosion in uncemented zones is the most common cause of casing failure. This can occur if uncemented sections of the casing are exposed to corrosive substances such as brine or hydrogen sulfide (Renpu, 2011). Corrosion commonly occurs at the collars that connect sections of casing or

[1] Internal mechanical integrity tests (MITs), such as casing inspection logs or caliper logs, annulus pressure monitoring, and pressure testing, can provide early warning of a problem, such as a leak, within the casing. It is important to note that if a well fails an MIT, this does not mean there is a failure of the well or that drinking water resources are impacted. An MIT failure is a warning that something needs to be addressed, and a loss of integrity is an event that may result in fluid movement from the well if remediation is not performed.

at other places where other equipment is attached to the casing. Corrosion at collars may exacerbate problems with loose or poorly designed connections, which are another common cause of casing leaks (King and King, 2013; Brufatto et al., 2003). Watson and Bachu (2009) found that 66% of all casing corrosion occurred in uncemented well sections, as shown in Pathway 1 of Figure 6-3.

Aging and use of the well contribute to casing degradation. Casing corrosion and degradation can occur over time and with extended use. Also, exposure to corrosive chemicals such as hydrogen sulfide, carbonic acid, and brines can accelerate corrosion. Therefore, the potential for fluid migration related to compromised casing tends to be higher in older wells. Ajani and Kelkar (2012) studied wells in Oklahoma and found a correlation between well age and integrity, specifically in wells spaced between 1,000 and 2,000 ft (305 and 610 m) from a well being fractured, the likelihood of impact to the well rose from approximately 20% to 60% as the well's age increased from 200 days to over 600 days. Age was also found to be a factor in well integrity problems in a study of wells in the Gulf of Mexico (Brufatto et al., 2003). The studies mentioned did not look for evidence of such fluid movement pathways, however. Because of this potential for degradation of well components in older wells and the related potential for fluid movement, reentering older wells for re-fracturing may contribute to the development of fluid movement pathways within those wells.

As noted above, the casing and cement work together to strengthen the well and provide zonal isolation. Uncemented casing does not necessarily lead to fluid migration. However, migration can occur if the casing in an uncemented zone fails during hydraulic fracturing operations or if the uncemented section is in contact with fluid-containing zones (including the zone being fractured). Sections of well casing that are uncemented may allow fluid migration into the annulus between the casing and formation. Fluid is free to migrate between formations in contact with the uncemented well section in any uncemented annulus without significant hole sloughing or wellbore swelling. If the uncemented section extends through a drinking water resource, fluid migration into the drinking water resource may occur.

Other well integrity problems have been found to vary with the well environment, particularly environments with high pressures and temperatures. Wells in high pressure/high temperature environments, wells with thermal cycling, and wells in corrosive environments can have life expectancies of less than 10 years (King and King, 2013).

The depth of the surface casing relative to the base of the drinking water resource to be protected is an important factor in protecting the drinking water resource. In a limited risk modeling study of selected injection wells in the Williston Basin, Michie and Koch (1991) found the risk of aquifer contamination from leaks from the inside of the well to the drinking water resource was 7 in 1,000,000 injection wells if the surface casing was set deep enough to cover the drinking water resource, and that the risk increased to 6 in 1,000 wells if the surface casing was not set deeper than the bottom of the drinking water resource. An example where surface casing did not extend below drinking water resources comes from an investigation of 14 drinking water wells with alleged water quality problems in the Wind River and Fort Union formations in Wyoming

(WYOGCC, 2014). The state found that the surface casing of oil and gas wells was shallower than the depth of 3 of the 14 drinking water wells. Some of the oil and gas wells with shallow surface casing had elevated gas pressures in their annuli (WYOGCC, 2014).

During hydraulic fracturing operations near Killdeer, in Dunn County, North Dakota, the production, surface, and conductor casing of the Franchuk 44-20 SWH well ruptured, causing fluids to spill to the surface (Jacob, 2011). The rupture occurred during the 5th of 23 stages of hydraulic fracturing when the pressure spiked to over 8,390 psi (58 MPa). The casing failed, and ruptures were found in two locations along the production casing—one just below the surface and one at about 55 ft (17 m) below ground surface. The surface casing ruptured in three places down to a depth of 188 ft (57 m), and the conductor casing ruptured in one place. Despite a shutdown of the pumps, the pressure was still sufficient to cause fluid to travel through the ruptured casings and to bubble up at the surface. Ultimately, nearly 168,000 gallons (636 m^3) of fluids and approximately 2,860 tons (2,595 metric tons) of contaminated soil were removed from the site (Jacob, 2011). Sampling of two monitoring wells in the drinking water aquifer identified brine contamination that was consistent with mixing of local ground water with brine from Madison Group formations, which the well had penetrated (U.S. EPA, 2015j). Tert-butyl alcohol (TBA) was also found in the two wells with brine contamination. The TBA was consistent with degradation of tert-butyl hydroperoxide, a component of the fracturing fluid used in the Franchuk well. The rupture (blowout) was the only source consistent with findings of high brine and TBA concentrations in the two wells.[1] For additional information about impacts at the Killdeer site, see Text Box 5-12 in Section 5.5 and Section 6.3.2.2.

Inadequate casing or cement can respond poorly when blowout preventers activate. When blowout preventers are activated, they immediately stop the flow in the well, which can create a sudden pressure increase in the well. If the casing or cement are not strong enough to withstand the increased pressure when this occurs, well components can be damaged (The Royal Society and the Royal Academy of Engineering, 2012) and the potential for fluid release and migration in the subsurface increases. Blowouts can also occur during the production phase, and cause spills on the surface that can affect drinking water resources; see Section 7.7.3.2.

While well construction and hydraulic fracturing techniques continue to change, the pressure- and temperature-related stresses associated with hydraulic fracturing remain as factors that can affect the integrity of the well casing. Several studies have evaluated the components of a well that can affect well performance and integrity. Ingraffea et al. (2014) conducted a study of well integrity in Pennsylvania production wells to assess overall trends in well integrity. This study identified a significant increase in well integrity problems from 2009 to 2011 rising to 5% to 6% of all wells, followed by a decrease beginning in 2012 to about 2% of all wells, a reduction of approximately 100

[1] A well blowout is the uncontrolled flow of fluids out of a well. A blowout preventer (BOP) is casinghead equipment that prevents the uncontrolled flow of oil, gas, and mud from the well by closing around the drill pipe or sealing the hole (Oil and Gas Mineral Services, 2010). BOPs are typically a temporary component of the well, in place only during drilling and perhaps through hydraulic fracturing operations.

violations among 3,000 wells. The rise in well integrity problems between 2009 and 2011 coincided with an increase in the number of wells in unconventional reservoirs.

Emerging isotopic techniques can be used to identify the extent to which stray gas occurring in drinking water resources is linked to casing failure (see Text Box 6-2 for more information on stray gas). Darrah et al. (2014) used hydrocarbon and noble gas isotope data to investigate the source of gas in eight identified "contamination clusters." Seven of these clusters were stripped of atmospheric gases (Ar^{36} and Ne^{20}) and were enriched in crustal gases, indicating the gas migrated quickly from depth without equilibrating with intervening formations. The rapid transport was interpreted to mean that the migration did not occur along natural fractures or pathways, which would have allowed equilibration to take place. Possible explanations for the rapid migration include transport up the well and through a leaky casing (Pathway 1 in Figure 6-3) or along uncemented or poorly cemented intervals from shallower depths (Pathways 2 through 5 in Figure 6-3). In four Marcellus Shale clusters, gas found in drinking water wells had isotopic signatures and ratios of ethane to methane that were consistent with those in the producing formation. The authors conclude that this suggests that gas migrated along poorly constructed wells from the producing formation, likely with improper, faulty, or failing production casings. In three clusters, the isotopic signatures and ethane to methane ratios were consistent with formations overlying the Marcellus. The authors suggest that this migration occurred from the shallower gas formations along uncemented or improperly cemented wellbores. In another Marcellus cluster in the study, deep gas migration was linked to a subsurface well, likely from a failed well packer.

Text Box 6-2. Stray Gas Migration.

Stray gas refers to the phenomenon of natural gas (primarily methane) migrating into shallow drinking water resources, into water wells, or to the surface (e.g., cellars, streams, or springs). Stray gas in the wellhead of a production well is an indicator of an active wellbore pathway. Methane is not a regulated drinking water contaminant, but it can initiate chemical and biological reactions that release or mobilize other contaminants, and gas can accumulate to explosive levels when allowed to exsolve (degas) from ground water in closed environments. Stray gas may originate from conventional and unconventional natural gas reservoirs, as well as from coal mines, landfills, leaking gas wells, leaking gas pipelines, and buried organic matter (Baldassare, 2011).

Detectable levels of dissolved hydrocarbons (generally methane and/or ethane) exist in most oxygen-poor aquifers, even in the absence of human activity (Gorody, 2012). Pre-drilling studies show that low levels of methane are frequently found in water wells in northern Pennsylvania and New York (Kappel, 2013; Kappel and Nystrom, 2012); one USGS study detected methane in 80% of sampled wells in Pike County, Pennsylvania (Senior, 2014). The origin of methane in ground water can be either thermogenic (produced by high temperatures and pressures in deeper formations, such as the gas found in the Marcellus Shale) or biogenic (produced in shallower formations by bacterial activity in anaerobic conditions). Occurrence of thermogenic methane in shallower formations depends upon the existence of a hydrocarbon source and pathways by which the gas can migrate. Interactions between hydrocarbon production and natural systems must also be considered. For example, Brantley et al. (2014) describe how northern Pennsylvania's glacial history may help explain why stray gas is more common there than in the southern part of the state.

Stray gas migration can be a technically complex phenomenon, in part because there are many potential routes for migration. The lack of detailed monitoring data, including a lack of baseline measurements prior to hydrocarbon production, often further complicates stray gas research. Examining the concentrations and isotopic compositions of methane and higher molecular weight hydrocarbons such as ethane and propane can aid in determining the source of stray gas (Tilley and Muehlenbachs, 2012; Baldassare, 2011; Rowe and Muehlenbachs, 1999). Isotopic composition and methane-to-ethane ratios can help determine whether the gas is thermogenic or biogenic in origin and whether it is derived from shale or other formations (Gorody, 2012; Muehlenbachs et al., 2012; Barker and Fritz, 1981). Isotopic analysis can also be used to identify the strata where the gas originated and provide evidence for migration mechanisms (Darrah et al., 2014).

However, determining the source of methane does not necessarily establish the migration pathway. Well casing and cementing issues may be an important source of stray gas problems (Jackson et al., 2013b); however, other potential subsurface pathways are also discussed in the literature. Multiple researchers (e.g., Jackson et al., 2013b; Molofsky et al., 2013; Révész et al., 2012; Osborn et al., 2011) have described biogenic and/or thermogenic methane in ground water supplies in Marcellus gas production areas, although the pathways of migration are generally not apparent. The Osborn et al. (2011) study found that thermogenic methane concentrations in well water increased with proximity to Marcellus Shale production sites, while Molofsky et al. (2013) found the presence of gas to be more closely correlated with topography and elevation. Similarly, Siegel et al. (In Press) found no correlation between methane in ground water and proximity to production wells.

The EPA conducted case studies that included investigating stray gas in northeastern Pennsylvania and the Raton Basin of Colorado. In northeastern Pennsylvania, many drinking water wells within the study area were found to have elevated methane concentrations. For some of the wells, the EPA concluded that the methane (both thermogenic and biogenic) was naturally occurring background gas not attributable to gas exploration activities. In others, it appeared that non-background methane had entered the water wells following well drilling and hydraulic fracturing. In most cases, the methane in the wells likely originated from intermediate formations between the production zone and the surface; however, in some cases, the methane appears to have originated from deeper layers such as those where the Marcellus Shale is found (U.S. EPA, 2015o). The Raton Basin case study examined the Little Creek Field, where potentially explosive quantities of methane were vented into a number of drinking water wells in 2007. The methane was found to be primarily thermogenic in origin, modified by biologic oxidation (U.S. EPA, 2015l). Secondary biogeochemical changes related to the migration and reaction of methane within the shallow drinking water aquifer were reflected in the characteristics of the Little Creek Field ground water (U.S. EPA, 2015l).

While the sources of methane in the two studies could be determined with varying degrees of certainty, attempts to definitively identify the pathways of migration have been inconclusive. In northeastern Pennsylvania, while the sources could not be definitively determined, the Marcellus Shale could not be excluded as a potential source in some wells based on isotopic signatures, methane-to-ethane ratios, and isotope reversal properties (U.S. EPA, 2014i). The Pennsylvania

Department of Environmental Protection (PA DEP) cited at least two operators for failure to prevent gas migration at a number of wells within the study area. Evidence cited by the state included isotopic comparison of gas samples from drinking water wells, water bodies, and gas wells; inadequate cement jobs; and sustained casing pressure (although, under Pennsylvania law, oil or gas operators can be cited if they cannot disprove the contamination was caused by their well using pre-drilling samples). A separate study (Ingraffea et al., 2014) showed that wells in this area had higher incidences of well integrity problems relative to wells in other parts of Pennsylvania. In the Raton Basin, the source of methane was identified as the Vermejo coalbeds. Based on modeling of the Raton Basin study area, the migration could be explained either by migration along natural rock features in the area or by migration caused by fracturing around the wellbore (U.S. EPA, 2015l). Because the gas production wells were shut in shortly after the incident began, the wells could not be inspected to determine whether an integrity failure in the wellbore was a likely cause of the migration.[1]

These two case studies illustrate the considerations involved with understanding stray gas migration and the difficulty in determining sources and migration pathways. In order to more conclusively determine sources and migration pathways, studies in which data are collected on well integrity and ground water methane concentrations both before and after hydraulic fracturing operations, in addition to the kinds of data summarized above, would be needed.

6.2.2.2. Pathways Related to Cement

Fluid movement may result from inadequate well design or construction (e.g., cement loss or other problems that arise in cementing of unconventional wells) or degradation of the cement over time (e.g., corrosion or the formation of microannuli), which may, if undetected and not repaired, cause the cement to succumb to the stresses exerted during hydraulic fracturing.[2,3] The well cement must be able to withstand the subsurface conditions and the stresses encountered during hydraulic fracturing operations. In this section, we present indicators that pathways within the cement are present or allowing fluid movement.

Uncemented zones can allow fluids or brines to move into drinking water resources. An improper cement job can fail to maintain zonal isolation in several ways. The first is by poor cement placement. If a fluid-containing zone is left uncemented, the open annulus between the formation and casing can act as a pathway for migration of that fluid. Fluids can enter the wellbore along any uncemented section of the wellbore if a sufficient pressure gradient is present. Once the fluids have entered the wellbore, they can travel along the entire uncemented length of the wellbore, unless the wellbore sloughs in around the casing.

Because of its low density, gas will migrate up the wellbore if an uncemented wellbore is exposed to a gas-containing formation. Gas may then be able to enter other formations (including drinking

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[1] Shutting in a well refers to sealing off a well by either closing the valves at the wellhead, a downhole safety valve, or a blowout preventer.

[2] External MITs, such as temperature logs, noise logs, oxygen activation logs, and radioactive tracer logs, can indicate improper cementing or degradation of the cement.

[3] Microannuli are very small channels that form in the cement and that may serve as pathways for fluid migration to drinking water resources.

water resources) if the wellbore is uncemented and the pressure in the annulus is sufficient to force fluid into the surrounding formation (Watson and Bachu, 2009). The rate at which the gas can move will depend on the difference in pressure between the annulus and the formation (Wojtanowicz, 2008). Harrison (1985) also demonstrated that such uncemented annuli could result in the migration of gas into overlying formations open to the annulus.

In several cases, poor or failed cement has been linked to stray gas migration (see Text Box 6-2). A Canadian study found that uncemented portions of casing were the most significant contributors to gas migration (Watson and Bachu, 2009). The same study also found that 57% of all casing leaks occurred in uncemented segments. In the study by Darrah et al. (2014) (see Section 6.2.2.1) using isotopic data, four clusters of gas contamination were linked to cement issues. In three clusters in the Marcellus and one in the Barnett, gas found in drinking water wells had isotopic signatures consistent with intermediate formations overlying the producing zone. This suggests that gas migrated from the intermediate units along the well annulus, along uncemented portions of the wellbore or through channels or microannuli. In a study in Utah, Heilweil et al. (2013) used a stream-based methane monitoring method to identify a case of potential gas migration near a well with defective casing or cement.

Cementing of the surface casing is the primary aspect of well construction that protects drinking water resources. Most states require the surface casing to be set and cemented from the level of the lowermost drinking water resource to the surface (GWPC, 2014). Most wells—including those used in hydraulic fracturing operations—have such cementing in place. Among the wells represented in the Well File Review, surface casing, which was found to be fully cemented in 93% of wells, extended below the base (i.e., the bottom, deepest, or lowermost part) of the protected ground water resource reported by well operators in an estimated 55% of wells (12,600 wells).[1] In an additional 28% of wells (6,400 wells), the operator-reported protected ground water resources were fully covered by the next cemented casing string. A portion of the annular space between casing and the operator-reported protected ground water resources was uncemented in at least 3% of wells (600 wells) (U.S. EPA, 2015o).[2] Improper placement of cement can lead to cement integrity problems. For example, an improper cement job can be the result of loss of cement during placement into a formation with high porosity or fractures, causing a lack of adequate cement across a water- or brine-bearing zone. Additionally, failure to use cement that is compatible with the anticipated subsurface conditions, failure to remove drilling fluids from the wellbore, and improper centralization of the casing in the wellbore can all lead to the formation of channels (i.e., small connected voids) in the cement during the cementing process (McDaniel et al., 2014; Sabins, 1990). If the channels are small and isolated, they may not lead to fluid migration. However, if they

[1] In the in the Well File Review, protected ground water resources were reported by well operators. For most wells represented in the Well File Review, protected ground water resources were identified by the well operators from state or federal authorization documents. Other data sources used by well operators included aquifer maps, data from offset production wells, open hole log interpretations done by operators, operator experience, online databases, and references to a general requirement by the oil and gas agency.
[2] The well files representing an estimated 8% of wells in the Well File Review did not have sufficient data to determine whether the operator-reported protected ground water resource was uncemented or cemented. In these cases, there was ambiguity either in the depth of the base or the top of the operator-reported protected ground water resource.

are long and connected, extending across multiple formations or connecting to other existing channels or fractures, they can present a pathway for fluid migration. Figure 6-3 shows a variety of pathways for fluid migration that are possible from failed cement jobs.

One example of how cement problems associated with hydraulic fracturing contributed to a contamination incident occurred in Bainbridge, Ohio. This incident was particularly well studied by the Ohio Department of Natural Resources (ODNR, 2008) and by an expert panel (Bair et al., 2010). The level of detail available for this case is not typically found in studies of such events but was collected because of the severity of the impacts and the resulting legal action. The English #1 well was drilled to a depth of 3,900 ft (1,189 m) below ground surface (bgs) with the producing formation located between 3,600 and 3,900 ft (1,097 and 1,189 m) bgs. Overlying the producing formation were several uneconomic formations that contained over-pressured gas (i.e., gas at pressures higher than the hydrostatic pressure exerted by the fluids within the well).[1] The original cement design required the cement to be placed 700–800 ft (213–244 m) above the producing formation to seal off these areas. During cementing, however, the spacer fluid failed to return to the surface, indicating lost cement, and the cement did not reach the intended height.[2] Despite the lack of sufficient cement, the operator proceeded with hydraulic fracturing.

During the fracturing operation, about 840 gallons (3.2 m^3) of fluid flowed up the annulus and out of the well. When the fluid began flowing out of the annulus, the operator immediately ceased operations. About a month later, there was an explosion in a nearby house where methane had entered from an abandoned and unplugged drinking water well that was connected to the cellar (Bair et al., 2010). In addition to the explosion, the over-pressured gas entering the aquifer resulted in the contamination of 26 private drinking water wells with methane.

Contamination at Bainbridge was the result of inadequate cement. The ODNR determined that failure to cement the over-pressured gas formations, proceeding with the fracturing operation without verifying there was adequate cement, and the extended period during which the well was shut in all contributed to the contamination of the aquifer with stray gas (ODNR, 2008). Cement logs found the cement top was at 3,640 ft (1,109 m) bgs, leaving the uneconomic gas-producing formations and a portion of the production zone uncemented. Hydraulic fracturing fluids flowing out of the annulus provided an indication that the fracturing had created a path from the producing formation to the well annulus. This pathway may have allowed gas from the producing formation along with gas from the uncemented formation to enter the annulus. Because the well was shut in, the pressure in the annulus could not be relieved, and the gas eventually traveled through natural fractures surrounding the wellbore into local drinking water aquifers. (During the time the well was shut in, natural gas seeped into the well annulus and pressure built up from an initial pressure of 90 psi (0.6 MPa) to 360 psi (2.5 MPa)). From the aquifer, the gas moved into drinking water wells and from one of those wells into a cellar, resulting in the explosive accumulation of gas.

[1] Hydrostatic pressure is the pressure exerted by a column of fluid at a given depth. Here, it refers to the pressure exerted by a column of drilling mud or cement on the formation at a particular depth.
[2] Spacer fluid is a fluid pumped before the cement to clean drilling mud out of the wellbore.

While limited literature is available on construction flaws in wells that have been used in hydraulic fracturing operations, several studies have examined construction flaws in oil and gas wells in general. One study that examined reported drinking water contamination incidents in Texas identified 10 incidents related to drilling and construction activities among 250,000 oil and gas wells (Kell, 2011). The study noted that many of the contamination incidents were associated with wells that were constructed before Texas revised its regulations on cementing in 1969 (it is not clear how old the wells were at the time the contamination occurred). Because this study relied on reported incidents, it is possible that other wells exhibited integrity issues but did not result in contamination of a drinking water well or were not reported. Therefore, this should be considered a low-end estimate of the number of well integrity issues that could be tied directly to drilling and construction activities. It is important to note that the 10 contamination incidents identified were not associated with wells that were hydraulically fractured (Kell, 2011).

Several investigators have studied violations information from the PA DEP online violation database to evaluate the rates of and possible factors contributing to well integrity problems, including those related to cement. The results of these studies are summarized in Table 6-1. While all of the studies shown in the table used the same database, their results vary, not only because of the different time frames, but also because they used different definitions of what violations constituted an integrity problem or failure. For example, Considine et al. (2012) considered all events resulting in environmental damage—including effects such as erosion—and found a relatively high violation rate. Davies et al. (2014) and Ingraffea et al. (2014) investigated violations related to well integrity, while Vidic et al. (2013) looked only at well integrity violations that resulted in fluid migration out of the wellbore; these more specific studies found relatively lower violation rates. Olawoyin et al. (2013) performed a statistical analysis that weighted violations based on risk and found that the most risky violations included those involving pits, erosion, waste disposal, and blowout preventers.

Table 6-1. Results of studies of PA DEP violations data that examined well failure rates.

Study	Violations investigated	Data timeframe	Key findings[a]

Study	Violations investigated	Data timeframe	Key findings[a]
Considine et al. (2012)	Violations resulting in environmental damage (3,533 wells studied)	2008–2011	Of 845 environmental damage incidents (which resulted in 1,144 violations), approximately 10% were related to casing or cement problems. The overall violation rate dropped from 52.9% of all wells in 2008 to 20.8% of all wells in 2011.
Davies et al. (2014)	Failure of one of the barriers preventing fluid migration (8,030 wells studied)	2005–2013	Approximately 5% of wells received this type of violation. The incident rate increased to 6.3% when failures noted on forms, but not resulting in violations, were included.
Ingraffea et al. (2014)	Violations and inspection records indicating structural integrity loss (3,391 wells studied)	2000–2012	Wells in unconventional reservoirs experienced a rate of structural integrity loss of 6.2%, while the rate for conventional wells was 1%.
Vidic et al. (2013)	Failure of cement/casing that allowed fluid to leak out (6,466 wells studied)	2008–2013	Approximately 3.4% of wells received this type of violation.
Olawoyin et al. (2013)	All violations (2,001 wells studied)	2008–2010	Analysis of 2,601 violations from 65 operators based on weighted risks found that potentially risky violations increased 342% over the study period, while total violations increased 110%.

[a] Note: While all of these studies used the same database, their results vary because they studied different time frames and used different definitions of what violations constituted an integrity problem or failure.

Because a significant portion of Pennsylvania's recent oil and gas activity is in the Marcellus Shale, many of the wells in these studies were most likely used for hydraulic fracturing. For example, Ingraffea et al. (2014) found that approximately 16% of the oil and gas wells drilled in the state between 2000 and 2012 were completed in unconventional reservoirs, and nearly all of these wells were used for hydraulic fracturing. Wells drilled in unconventional reservoirs experienced higher rates of structural integrity loss than conventional wells drilled during the same time period (Ingraffea et al., 2014). The authors did not compare rates of structural integrity loss in conventional wells that were and were not used for hydraulic fracturing; they assumed that unconventional wells were hydraulically fractured and conventional wells were not.

Violation rates resulting in environmental pollution among all wells dropped from 52.9% in 2008 to 20.8% in 2011 (Considine et al., 2012), and the drop may be due to a number of factors. Violations related to failure of cement or other well components represented a minority of all well violations. Of 845 events that caused environmental contamination, including but not limited to contamination of drinking water resources, Considine et al. (2012) found that about 10% (85 events) were related to casing and cement problems. The rest of the incidents were related to site restoration and spills (the violations noted are confined to those incidents that caused environmental damage i.e., the analysis excluded construction flaws that did not have adverse environmental effects).

Another source of information on contamination caused by wells is positive determination letters (PDLs) issued by the PA DEP. PDLs are issued in response to a complaint when the state determines that contamination did occur in proximity to oil and gas activities. The PDLs take into account the impact, timing, well integrity, and formation permeability; however, liability is presumed for wells within a given distance if the oil and gas operator cannot refute that they caused the contamination, based on pre-drilling sampling (Brantley et al., 2014).[1] Brantley et al. (2014) examined these PDLs, and concluded that approximately 20 unconventional gas wells impacted water supplies between 2008 and 2012; this equates to 0.1% to 1% of the 6,061 wells spudded between 2008 and 2012 (it is unclear exactly how many PDLs are linked to an individual well). While these oil and gas wells were linked to contamination of wells and springs, the mechanisms for the impacts (including whether fluids may have been spilled at the surface or if there was a pathway through the well or through the subsurface rock formation to the drinking water resource) were not described by Brantley et al. (2014). We did not perform a full and independent review of the PDLs for this assessment.

While the studies discussed above present possible explanations for higher violation incidences in hydraulically fractured wells, it should be noted that other explanations that are not specific to hydraulic fracturing are also possible. These could include different inspection protocols and different formation types.

Cementing in horizontal wells, which are commonly hydraulically fractured, presents challenges that can contribute to higher rates of integrity issues. The observation by Ingraffea et al. (2014) that wells drilled in unconventional reservoirs experience higher rates of structural integrity loss than conventional wells is supported by conclusions of Sabins (1990), who noted that horizontal wells have more cementing problems because they are more difficult to center properly and can be subject to settling of solids on the bottom of the wellbore. Cementing in horizontal wells presents challenges that can contribute to higher rates of integrity issues.

Thermal and cyclic stresses caused by intermittent operation also may stress cement (King and King, 2013; Ali et al., 2009). Increased pressures and cyclic stresses associated with hydraulic fracturing operations can contribute to cement integrity losses and, if undetected, small integrity problems can lead to larger ones. Temperature differences between the (typically warmer) subsurface environment and the (typically cooler) injected fluids, followed by contact with the (typically warmer) flowback water, can lead to contraction of the well materials (both casing and cement), which introduces additional stresses. Similar temperature changes may occur when

[1] Under Pennsylvania's Oil and Gas Act, operators of oil or gas wells are presumed liable if water supplies within 1,000 ft (305 m) were impacted within 6 months of drilling, unless the claim is rebutted by the operator; this was expanded to 2,500 ft (762 m) and 12 months in 2012.

multiple fracturing stages are performed. Because the casing and cement have different mechanical properties, they may respond differently to these stress cycles and debond.

Several studies illustrate the effects of cyclic stresses. Dusseault et al. (2000) indicate that wells that have undergone several cycles of thermal or pressure changes will almost always show some debonding between cement and casing. Microannuli formed by this debonding can be conduits for gas migration, in particular because the lighter density of gas provides a larger driving force for migration through the microannuli than for heavier liquids.[1] One laboratory study indicated that microannuli on the order of 0.01 in (0.3 mm) could increase effective cement permeability from 1 nD (1×10^{-21} m^2) in good quality cement up to 1 mD (1×10^{-15} m^2) (Bachu and Bennion, 2009). This six-order magnitude increase in permeability shows that even small microannuli can significantly increase the potential for flow through the cement. Typically, these microannuli form at the interface between the casing and cement or between the cement and formation. Debonding and formation of microannuli can occur through intermittent operation, pressure tests, and workover operations (Dusseault et al., 2000).[2] While a small area of debonding may not lead to fluid migration, the microannuli in the cement that result from the debonding can serve as initiation points for fracture propagation if re-pressurized gas enters the microannulus (Dusseault et al., 2000).

The Council of Canadian Academies (2014) found that the repetitive pressure surges that occur during the fracturing process would make maintaining an intact cement seal more of a challenge in wells that are hydraulically fractured. Wang and Dahi Taleghani (2014) performed a modeling study that showed that hydraulic fracturing pressures could initiate annular cracks in cement. Another study of well data indicated that cement failure rates are higher in intermediate casings compared to other casings (McDaniel et al., 2014). The failures occurred after drilling and completion of wells, and the authors surmised that the cement failures were most likely due to cyclical pressure stresses caused by drilling. Theoretically, such cyclical pressure events could also be experienced during multiple stage hydraulic fracturing. Mechanical stresses associated with well operation or workovers and pressure tests also may lead to small cracks in the cement, which may provide migration pathways for fluid.

Corrosion can lead to cement failure. Cement can fail to maintain integrity as a result of degradation of the cement after the cement is set. Cement degradation can result from attack by corrosive brines or chemicals such as sulfates, sulfides, and carbon dioxide that exist in formation fluids (Renpu, 2011). These chemicals can alter the chemical structure of the cement, resulting in increased permeability or reduced strength and leading to loss of cement integrity over time. Additives or specialty cements that can decrease cement susceptibility to specific chemical components are available.

[1] Microannuli can also form due to an inadequate cement job, e.g., poor mud removal or improper cement placement rate.
[2] A workover refers to any maintenance activity performed on a well that involves ceasing operations and removing the wellhead. Depending on the purpose of the workover and the tools used, workovers may induce pressure changes in the well.

6.2.2.3. Sustained Casing Pressure

An example of how the issues related to casing and cement discussed in the preceding sections can work together and be difficult to differentiate can be seen in the case of sustained casing pressure.[1] Sustained casing pressure is an indicator that pathways within the well related to the well's casing, cement, or both allowed fluid movement to occur. Sustained casing pressure can result from casing leaks, uncemented intervals, microannuli, or some combination of the three, which can be an indication that a well has lost integrity. Sustained casing pressure can be observed when an annulus (either the annulus between the tubing and production casing or between any two casings) is exposed to a source of nearly continuous elevated pressure. Goodwin and Crook (1992) found that sudden increases in sustained casing pressure occurred in wells that were exposed to high temperatures and pressures. Subsequent logging of these wells showed that the high temperatures and pressures led to shearing of the cement/casing interface and a total loss of the cement bond.

Sustained casing pressure occurs more frequently in older wells and horizontal or deviated wells. One study found that sustained casing pressure becomes worse as a well ages. Sustained casing pressure was found in less than 10% of wells that were less than a year old, but was present in up to 50% of 15-year-old wells (Brufatto et al., 2003). While these wells may not have been hydraulically fractured, the study demonstrates that older wells can exhibit more integrity problems. Watson and Bachu (2009) found that a higher portion of deviated wells had sustained casing pressure compared to vertical wells. Increased pressures, cyclic stresses (Syed and Cutler, 2010), and difficulty in cementing horizontal wells (Sabins, 1990) also may lead to increased instances of sustained casing pressure in wells where hydraulic fracturing occurs (Muehlenbachs et al., 2012; Rowe and Muehlenbachs, 1999).

Sustained casing pressure can be a concern for several reasons. If the pressures are allowed to build up to above the burst pressure of the exterior casing or the collapse pressure of the interior casing, the casing may fail. Increased pressure can also cause gas or liquids to enter lower-pressured formations that are exposed to the annulus either through leaks or uncemented sections. Laboratory experiments by Harrison (1985) demonstrated that over-pressurized gas in the annulus could cause rapid movement of gas into drinking water resources if a permeable pathway exists between the annulus and the ground water. Over-pressurization of the annulus can be avoided by venting the annulus to the atmosphere.

In a few cases, sustained casing pressure in wells that have been hydraulically fractured may have been linked to drinking water contamination, although it is challenging to definitively determine the actual cause. In one study in northeastern Pennsylvania, hydrocarbon and isotope concentrations were used to investigate stray gas migration into domestic drinking water (U.S. EPA,

[1] Sustained casing pressure is pressure in any well annulus that is measurable at the wellhead and rebuilds after it is bled down, not caused solely by temperature fluctuations or imposed by the operator (Skjerven et al., 2011). If the pressure is relieved by venting natural gas from the annulus to the atmosphere, it will build up again once the annulus is closed (i.e., the pressure is sustained). The return of pressure indicates that there is a small leak in a casing or through uncemented or poorly cemented intervals that exposes the annulus to a pressured source of gas that is actively being used. It is possible to have pressure in more than one of the annuli.

2014i). While the composition of the gas in the water wells was consistent with that of the gas found in nearby gas wells with high casing pressures, other possible sources of the gas could not be ruled out. Several gas wells in the study area were cited by the PA DEP for having elevated casing annulus pressures. In another example in Alberta, Canada, 14% of wells drilled since 1971 have shown serious sustained casing flow, defined as more than 10,594 ft^3 (300 m^3)/day at pressures higher than 0.48 psi/ft (11 kPa/m) times the surface casing depth (Jackson and Dusseault, 2014). Another study in the same area found gas in nearby drinking water wells had a composition that was consistent with biogenic methane mixing with methane from nearby coalbed methane and deeper natural gas fields (Tilley and Muehlenbachs, 2012).

Adequate well design, detection (i.e., through annulus pressure monitoring), and repair of sustained casing pressure reduce the potential for fluid movement. Watson and Bachu (2009) found that regulations that required monitoring and repair of sustained casing vent flow or sustained casing pressure had a positive effect on lowering leak rates. The authors also found that wells initially designed for injection experienced sustained casing pressure less often than those that were retrofitted (Watson and Bachu, 2009).

Another study in Mamm Creek, Colorado, obtained similar results. The Mamm Creek field is in an area where lost cement and shallow, gas-containing formations are common. A number of wells in the area have experienced sustained casing pressure, and methane has been found in several drinking water wells along with seeps into local creeks and ponds. In one well, four pressured gas zones were encountered during well drilling and there was a lost cement incident, which resulted in the cement top being more than 4,000 ft (1,219 m) lower than originally intended. Due to high measured bradenhead pressure (661 psi, or 4.6 MPa), cement remediation efforts were implemented (Crescent, 2011; COGCC, 2004). The operator of this well was later cited by the Colorado Oil and Gas Conservation Commission (COGCC) for causing natural gas and benzene to seep into a nearby creek. The proposed route of contamination was contaminants flowing up the well annulus and then along a fault. The proposed contamination route appeared to be validated because, once remedial cementing was performed on the well, methane and benzene levels in the creek began to drop (Science Based Solutions LLC, 2014). In response to the incident, the state instituted requirements to identify and cement above the top of the highest gas-containing formation and to monitor casing pressures after cementing.

Not every well that shows positive pressure in the annulus poses a potential problem. Sustained pressure is only a problem when it exceeds the ability of the wellbore to contain it or when it indicates downhole communication problems (TIPRO, 2012). A variety of management options are available for managing such pressure including venting, remedial cementing, and use of kill fluids in the annulus (TIPRO, 2012).[1]

[1] A kill fluid is a weighted fluid with a density that is sufficient to overcome the formation pressure and prevent fluids from flowing up the wellbore.

6.3. Fluid Migration Associated with Induced Fractures within Subsurface Formations

In this section, we discuss potential pathways for fluid movement associated with induced fractures and subsurface geologic formations (outside of the well system described in Section 6.2). We examine the potential for fluid migration into drinking water resources by evaluating the development of migration pathways within subsurface formations, the flow of injected and formation fluids, and important factors that affect these processes.[1]

Fluid movement requires both a physical conduit (e.g., the permeable matrix pore volume or a fracture in the rock) and a driving force.[2] In subsurface rock formations, fluid movement is driven by the existence of a hydraulic gradient depending on elevation and pressure, which is also influenced by fluid density, composition, and temperature (Pinder and Celia, 2006). Pressure differentials in the reservoir and density-driven fluid buoyancy are the key forces governing fluid migration during and after hydraulic fracturing operations. Pressure differentials depend upon the initial conditions within these formations and are directly influenced by pressures that are created by injection or production regimes. Buoyancy depends on density differences among and between gases and liquids, and it causes fluid migration when and where these density differences exist along with a pathway (Pinder and Gray, 2008).

As hydraulic fracturing takes place, injected fluids leaving the well create fractures within the production zone and enter the formation through the newly created fractures. Unintended fluid migration may result from this fracturing process. Migration pathways to drinking water resources could develop as a result of changes in the subsurface flow or pressure regime associated with hydraulic fracturing; via fractures that extend beyond the intended formation or that intersect existing natural faults or fractures; or via fractures that intersect offset wells or other artificial structures (Jackson et al., 2013c). These subsurface pathways may facilitate the migration of fluids by themselves or in conjunction with the well-based pathways described in Section 6.2. Fluids potentially available for migration include both fluids that are injected into the well (including leakoff) and formation fluids (including brine or natural gas).[3]

[1] A subsurface formation (also referred to as a "formation" throughout this section) is a mappable body of rock of distinctive rock type(s), including the rock's pore volume (i.e., the void space within a formation that fluid flow can occur, as opposed to the bulk volume which includes both pore and solid phase volume), with a unique stratigraphic position.
[2] Permeability (i.e., intrinsic or absolute permeability) of formations describes the ability of water to move through the formation matrix, and it depends on the rock's grain size and the connectedness of the void spaces between the grains. Where multiple phases of fluids exist in the pore space, the flow of fluids also depends on relative permeabilities.
[3] Leakoff is the fraction of the injected fluid that infiltrates into the formation and is not recovered during production (Economides et al., 2007).

The potential for subsurface fluid migration into drinking water resources can be evaluated during two different time periods (Kim and Moridis, 2015):

1. Following the initiation of fractures within the reservoir prior to any production, when the injected fluid, pressurizing the formation, flows through the fractures and the fractures grow into the reservoir. Fluid leaks off into the formation, allowing the fractures to close except where they are held open by the proppant (Adachi et al., 2007).
2. During the production period, after fracturing is completed and pressure in the fractures is reduced, and hydrocarbons (along with produced water) flow from the reservoir into the well.

Note that these two time periods vary in duration. As described in Chapter 2, the first period of fracture creation and propagation (i.e., the hydraulic fracturing itself) is a relatively short-term process, typically lasting 2 to 10 days, depending on the number of stages in the fracture treatment design. On the other hand, operation of the well for production covers a substantially longer period (depending on many factors such as the amount of hydrocarbons in place and economic considerations), and can be as long as 40 or 60 years in onshore tight gas reservoirs (Ross and King, 2007).

The following discussion of potential subsurface fluid migration into drinking water resources focuses primarily on the physical movement of fluids and the factors that affect this movement. Section 6.3.1 describes the basic principles of subsurface fracture creation, geometry, and propagation, to provide context for the discussion of potential fluid migration pathways in Section 6.3.2. Geochemical and biogeochemical reactions among injected fluids, formation fluids, subsurface microbes, and rock formations are another important component of subsurface fluid migration and transport. See Chapter 7 for a discussion of the processes that affect pore fluid biogeochemistry and influence the chemical and microbial composition of flowback and produced water.

6.3.1. Overview of Subsurface Fracture Growth

Fracture initiation and growth is a highly complex process due to the heterogeneous nature of the subsurface environment. It depends on the geomechanical characteristics of rock formations, fluid properties, pore pressures, and subsurface stress fields. As shown in Figure 6-4, fracture formation is controlled by the three *in situ* principal compressive stresses: the vertical stress (S_V), the maximum horizontal stress (S_H), and the minimum horizontal stress (S_h). During hydraulic fracturing, pressurized fluid injection creates high pore pressures around the well. When the pressure exceeds the local least principal stress and the tensile strength of the rock, failure results and fractures form (Zoback, 2010; Fjaer et al., 2008).

Fractures propagate (increase in length) in the direction of the maximum principal stress, which is perpendicular to the direction of the least principal stress. Deep in the subsurface, the maximum principal stress is generally in the vertical direction because the overburden (the weight of overlying rock) is the largest single stress. Therefore, in deep formations, the local least principal stress is the minimum horizontal stress (S_h), and the principal fracture orientation is expected to be vertical. This is the scenario illustrated in Figure 6-4. At shallower depths, where the rock is subjected to less pressure from the overburden, more fracture propagation is expected to be in the horizontal direction. Using tiltmeter data from over 10,000 fractures in various North American reservoirs, Fisher and Warpinski (2012) found that fractures at approximately 4,000 ft (1,220 m) below the surface or deeper are primarily vertical (see below for more information on tiltmeters). Between approximately 4,000 and 2,000 ft (1,220 and 610 m), fracture complexity increases, and fractures at approximately 2,000 ft (610 m) or shallower are primarily horizontal (Fisher and Warpinski, 2012).[1] Horizontal fracturing can also occur in deeper settings in some less-common reservoir environments where the principal stresses have been altered by salt intrusions or similar types of geologic activity (Jones and Britt, 2009).

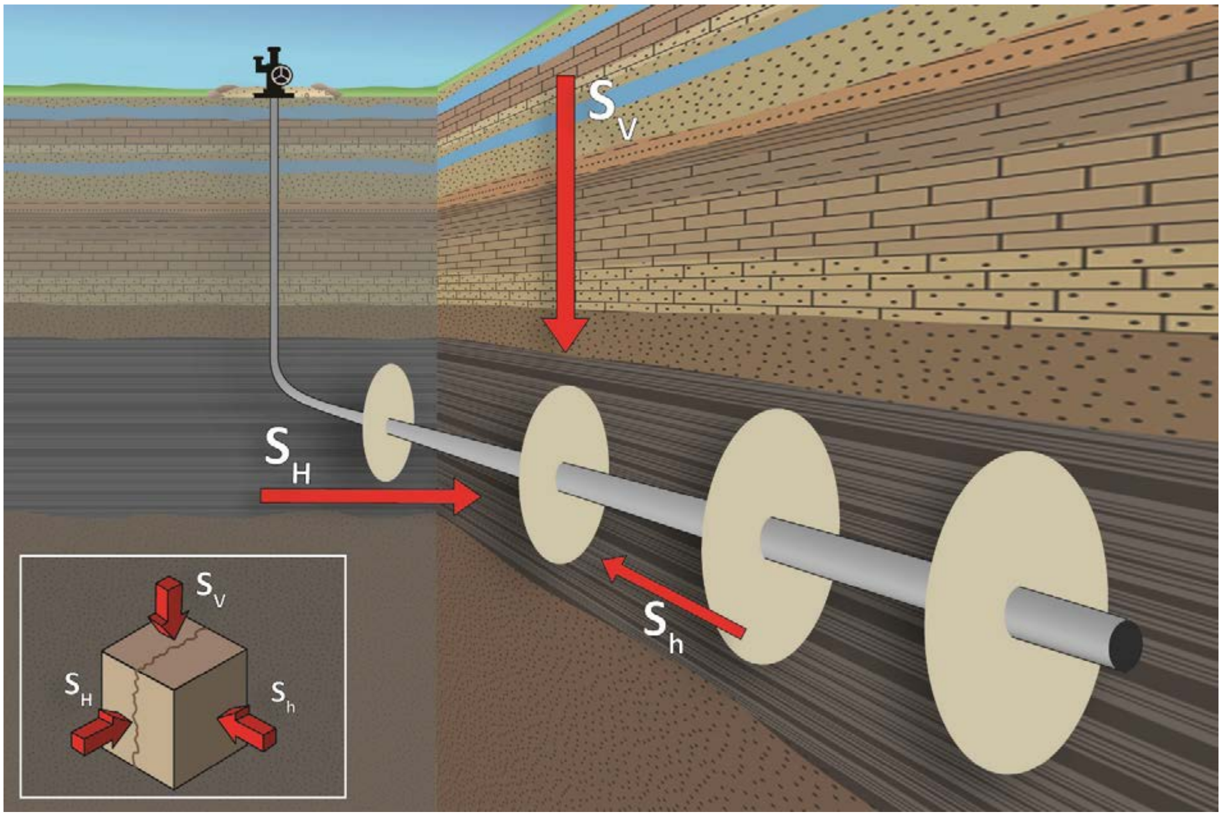

Figure 6-4. Hydraulic fracture planes (represented as ovals), with respect to the principal subsurface compressive stresses: S_V (the vertical stress), S_H (the maximum horizontal stress), and S_h (the minimum horizontal stress).

At depths greater than approximately 2,000 ft (610 m), the principal fracture orientation is expected to be vertical, as fractures propagate in the direction of S_H.

[1] Fracture complexity is the ratio of horizontal-to-vertical fracture volume distribution, as defined by Fisher and Warpinski (2012). Fracture complexity is higher in fractures with a larger horizontal component.

In addition to the principal subsurface stresses, other geomechanical and reservoir characteristics and operational factors affect fracture creation, geometry, and propagation.[1] These include initial reservoir pressure and saturation, injected fluid pressure or injection rate, geomechanical rock characteristics, reservoir heterogeneity, tensile strength, fluid type within fractures, and reservoir permeabilities (Kim and Moridis, 2015). Fracture creation is a complex process that involves interactions between multiple properties. For example, as described by Daneshy (2009), fracture height depends on a combination of parameters and processes including the material properties of geologic formations, pore pressures, stress differences in adjacent formations, shear failure (slippage) at the fracture tip, and the reorientation of the fracture as it crosses an interface between formations. Injection rates, the initial water saturation of the formation, and the type of fluid injected also have effects on fracture creation and propagation (Kim and Moridis, 2015, 2013).

Numerical modeling techniques have been developed to describe fracture creation and propagation and to provide a better understanding of this complex process (Kim and Moridis, 2013). Modeling hydraulic fracturing in shale or tight gas reservoirs requires integrating the physics of both flow and geomechanics to account for fluid flow, fracture propagation, and dynamic changes in pore volume and permeability. Some important flow and geomechanical parameters included in these types of advanced models are: permeability, porosity, Young's modulus, Poisson's ratio, and tensile strength, as well as heterogeneities associated with these parameters.[2] Some investigations using these models have indicated that the vertical propagation of fractures (due to tensile failure) may be limited by shear failure, which increases the permeability of the formation and leads to greater leakoff. These findings demonstrate that elevated pore pressure can cause shear failure, thus further affecting matrix permeability, flow regimes, and leakoff (Daneshy, 2009). Computational investigations have also indicated that slower injection rates can increase the amount of leakoff (Kim and Moridis, 2013).

In addition to their use in research settings, analytical and numerical modeling approaches are used by oil and gas companies to design hydraulic fracturing treatments and predict the extent of fractured areas (Adachi et al., 2007). Specifically, modeling techniques are used to assess the treatment's sensitivity to critical parameters such as injection rate, treatment volumes, fluid viscosity, and leakoff. The industry models range from simpler (typically two-dimensional) theoretical models to computationally more complicated and accurate three-dimensional models.

In addition to computational approaches, monitoring of hydraulic fracturing operations can provide insights into fracture development. Monitoring techniques involve both operational monitoring methods and "external" methods that are not directly related to the production operation. Operational monitoring refers to the monitoring of parameters including pressure, flow rate, fluid density, and additive concentrations using surface equipment and/or downhole sensors (Eberhard, 2011). This monitoring is conducted to ensure that the operation is proceeding as planned and to

[1] Fracture geometry refers to characteristics of the fracture such as height and aperture (width).
[2] Young's modulus, a ratio of stress to strain, is a measure of the rigidity of a material. Poisson's ratio is a ratio of transverse-to-axial (or latitudinal-to-longitudinal) strain, and it characterizes how a material is deformed under pressure. See Zoback (2010) for more information on the geomechanical properties of reservoir rocks.

determine if operational parameters need to be adjusted. Interpretation of pressure data can be used to better understand fracture behavior (e.g., Kim and Wang, 2014). Anomalies in operational monitoring data can also indicate whether an unexpected event has occurred, such as communication with another well (see Section 6.3.2.3).

The volume of fluid injected is typically monitored to provide information on the volume and extent of fractures created (Flewelling et al., 2013). However, numerical investigations have found that reservoir gas flows into the fractures immediately after they open from hydraulic fracturing, and injection pressurizes both gas and water within the fracture to induce further fracture propagation (Kim and Moridis, 2015). Therefore, the fracture volume can be larger than the injected fluid volume. As a result, simple estimation of fracture volume based on the amount of injected fluid may underestimate the growth of the vertical fractures, and additional information is needed to accurately predict the extent of fracture growth.

External monitoring technologies can also be used to collect data on fracture characteristics and extent during hydraulic fracturing and/or production. These monitoring methods can be divided into near-wellbore and far-field techniques. Near-wellbore techniques include the use of tracers, temperature logs, video logs, or caliper logs (Holditch, 2007). However, near-wellbore techniques and logs only provide information for, at most, a distance of two to three wellbore diameters from the well and are, therefore, not suited for tracking fractures for their entire length (Holditch, 2007). Far-field methods, such as microseismic monitoring or tiltmeters, are used if the intent is to estimate fracture growth and height across the entire fractured reservoir area. Microseismic monitoring involves placing one or more geophones in a position to detect the very small amounts of seismic energy generated during subsurface fracturing (Warpinski, 2009).[1] Monitoring these microseismic events gives an idea of the location and size of the fracture network, as well as the orientation and complexity of fracturing (Fisher and Warpinski, 2012). Tiltmeters, which measure extremely small deformations in the earth, can be used to determine the direction and volume of the fractures and, within certain distances from the well, to estimate their dimensions (Lecampion et al., 2005).

6.3.2. Migration of Fluids through Pathways Related to Fractures/Formations

As noted above, subsurface migration of fluids requires a pathway, induced or natural, with enough permeability to allow fluids to flow, as well as a hydraulic gradient physically driving the fluid movement. The following subsections describe and evaluate potential pathways for the migration of fracturing fluids, hydrocarbons, or other formation fluids from producing formations to drinking water resources. They also present cases where the existence of these pathways has been documented. As described above, potential subsurface migration pathways for fluid flow out of the production formation are categorized as follows: (1) flow of fluids into the production zone via induced fractures and out of the production zone via flow through the formation, (2) fracture overgrowth out of the production zone, (3) migration via fractures intersecting offset wells and

[1] Typical microseismic events associated with hydraulic fracturing have a magnitude on the order of -2.5 (negative two and half) (Warpinski, 2009).

other artificial structures, and (4) migration via fractures intersecting other geologic features. Although these four potential pathways are discussed separately here, they may act in combination with each other or in combination with pathways along the well (as discussed in Section 6.2) to affect drinking water resources.

In many cases (depending on fracture depth, height, and direction), the distance between the producing formation and the drinking water resource is one of the most important factors affecting the possibility of fluid migration between these formations (Reagan et al., 2015; Jackson et al., 2013c). This distance varies substantially among shale gas plays, coalbed methane plays, and other areas where hydraulic fracturing takes place in the United States (see Table 6-2). Many hydraulic fracturing operations target deep shale zones such as the Marcellus or Haynesville/Bossier, where the vertical distance between the top of the shale formation and the base of drinking water resources may be 1 mile (1.6 km) or greater. This is reflected in the Well File Review, which found that the largest proportion of wells used for hydraulic fracturing—an estimated 6,200 wells (27%)—had 5,000 to 5,999 ft (1,524 to 1,828 m) of measured distance along the wellbore between the induced fractures and the reported base of protected ground water resources (U.S. EPA, 2015o).[1] However, as shown in Table 6-2, operations in the Antrim and the New Albany plays take place at relatively shallower depths, with distances of 100 to 1,900 ft (30 to 579 m) between the producing formation and the base of drinking water resources. The Well File Review indicated that 20% of wells used for hydraulic fracturing (an estimated 4,600 wells) were located in areas with less than 2,000 ft (610 m) between the fractures and the base of protected ground water resources (U.S. EPA, 2015o). In coalbed methane plays, which are typically shallower than shale gas plays, these separation distances can be even smaller. For example, in the Raton Basin of southern Colorado and northern New Mexico, approximately 10% of coalbed methane wells have less than 675 ft (206 m) of separation between the gas wells' perforated intervals and the depth of local water wells. In certain areas of the basin, this distance is less than 100 ft (30 m) (Watts, 2006).

Some hydraulic fracturing operations are conducted within formations that contain drinking water resources (see Table 6-2). One example of hydraulic fracturing taking place within a geologic formation that is also used as a drinking water source is in the Wind River Basin in Wyoming (WYOGCC, 2014; Wright et al., 2012). Vertical gas wells in this area target the lower Eocene Wind River Formation and the underlying Paleocene Fort Union Formation, which consist of interbedded layers of sandstones, siltstones, and mudstones. The Wind River Formation also serves as the principal source of domestic, municipal, and agricultural water in this rural area. Hydraulic fracturing in rock formations that meet a state or federal definition of an underground source of drinking water is also known to take place in coalbed methane operations in the Raton Basin (U.S. EPA, 2015l), in the Powder River Basin of Montana and Wyoming (as described in Chapter 7), and in several other coalbed methane plays. In one field in Alberta, Canada, there is evidence that fracturing in the same formation as a drinking water resource (in combination with well integrity

[1] In the Well File Review, measured depth represents length along the wellbore, which may be a straight vertical distance below ground or may follow a more complicated path, if the wellbore is not straight and vertical.

problems; see Section 6.2.2.2) led to gas migration into water wells (Tilley and Muehlenbachs, 2012). However, no information is available on other specific incidents of this type.

Table 6-2. Comparing the approximate depth and thickness of selected U.S. shale gas plays and coalbed methane basins.

Shale data are reported in GWPC and ALL Consulting (2009) and NETL (2013); coalbed methane data are reported in ALL Consulting (2004) and U.S. EPA (2004). See Figures 2-2 and 2-4 in Chapter 2 for information on the locations of these basins, plays, and formations.

Basin/play/formation[a]	Approx. depth (ft [m] below surface)	Approx. net thickness (ft [m])	Distance between top of production zone and base of treatable water (ft [m])
Shale plays			
Antrim	600 to 2,200 [183 to 671]	70 to 120 [21 to 37]	300 to 1,900 [91 to 579]
Barnett	6,500 to 8,500 [1,981 to 2,591]	100 to 600 [30 to 183]	5,300 to 7,300 [1,615 to 2,225]
Eagle Ford	4,000 to 12,000 [1,219 to 3,658]	250 [76]	2,800 to 10,800 [853 to 3,292]
Fayetteville	1,000 to 7,000 [305 to 2,134]	20 to 200 [6 to 61]	500 to 6,500 [152 to 1,981]
Haynesville-Bossier	10,500 to 13,500 [3,200 to 4,115]	200 to 300 [61 to 91]	10,100 to 13,100 [3,078 to 3,993]
Marcellus	4,000 to 8,500 [1,219 to 2,591]	50 to 200 [15 to 61]	2,125 to 7,650 [648 to 2,332]
New Albany	500 to 2,000 [152 to 610]	50 to 100 [15 to 30]	100 to 1,600 [30 to 488]
Woodford	6,000 to 11,000 [1,829 to 3,353]	120 to 220 [37 to 67]	5,600 to 10,600 [1,707 to 3,231]
Coalbed methane basins			
Black Warrior (Upper Pottsville)	0 to 3,500 [0 to 1,067]	< 1 to > 70 [< 1 to > 21]	As little as zero[b]
Powder River (Fort Union)	450 to >6,500 [137 to 1,981]	75 [23]	As little as zero[b]
Raton (Vermejo and Raton)	< 500 to > 4,100 [< 152 to > 1,250]	10 to >140 [3 to >43]	As little as zero[b]
San Juan (Fruitland)	550 to 4,000 [168 to 1,219]	20 to 80 [6 to 24]	As little as zero[b]

Basin/play/formation[a]	Approx. depth (ft [m] below surface)	Approx. net thickness (ft [m])	Distance between top of production zone and base of treatable water (ft [m])

[a] For coalbed methane, values are given for the specific coal units noted in parentheses.
[b] Formation fluids in producing formations meet the definition of drinking water in at least some areas of the basin.

The overall frequency of occurrence of hydraulic fracturing in aquifers that meet the definition of drinking water resources across the United States is unknown. Some information, however, that provides insights on the occurrence and geographic distribution of this practice is available. According to the Well File Review, an estimated 0.4% of the 23,200 wells represented in that study had perforations used for hydraulic fracturing that were placed shallower than the base of the protected ground water resources reported by well operators (U.S. EPA, 2015o).[1] An analysis of produced water composition data maintained by the U.S. Geological Survey (USGS) provides insight into the geographic distribution of this practice. The USGS produced water database contains results from analyses of samples of produced water collected from more than 8,500 oil and gas production wells in unconventional formations (coalbed methane, shale gas, tight gas, and tight oil) within the continental United States.[2] Just over 5,000 of these samples, which were obtained from wells located in 37 states, reported total dissolved solids (TDS) concentrations. Because the database does not track whether samples were from wells that were hydraulically fractured, we selected samples from wells that were more likely to have been hydraulically fractured by restricting samples to those collected in 1950 or later and to those that were collected from wells producing from tight gas, tight oil, shale gas, or coalbed methane formations. This yielded 1,650 samples from wells located in Alabama, Colorado, North Dakota, Utah, and Wyoming.[3,4] The TDS concentrations among these samples ranged from approximately 90 mg/L to 300,000 mg/L. Samples from approximately 1,200 wells in Alabama, Colorado, Utah, and Wyoming reported TDS concentrations at or below 10,000 mg/L. This analysis, in conjunction with the result from the Well File Review, suggests that, while the overall frequency of occurrence may be low, the activity may be concentrated in some areas of the country.

[1] The 95% confidence interval reported in the Well File Review indicates that this phenomenon could have occurred in as few as 0.1% of the wells or in as many as 3% of the wells.
[2] We used the USGS Produced Water Geochemical Database Version 2.1 (USGS database v 2.1) for this analysis (http://energy.cr.usgs.gov/prov/prodwat/). The database is comprised of produced water samples compiled by the USGS from 25 individual databases, publications, or reports.
[3] See Chapter 2, Text Box 2-1, which describes how commercial hydraulic fracturing began in the late 1940s.
[4] For this analysis, we assumed that produced water samples collected in 1950 or later from shale gas, tight oil, and tight gas wells were from wells that had been hydraulically fractured. To estimate which coal bed methane wells had been hydraulically fractured, we matched API numbers from coal bed methane wells in the USGS database v 2.1 to the same API numbers in the commercial database DrillingInfo, in which hydraulically fractured wells had been identified by EPA using the assumptions described in Section 2.3.1. Wells with seemingly inaccurate (i.e., less than 12 digit) API numbers were also excluded. Only coalbed methane wells from the USGS database v 2.1 that matched API numbers in the DrillingInfo database were retained for this analysis.

6.3.2.1. Flow of Fluids Out of the Production Zone

One potential pathway for fluid migration out of the production formation into drinking water resources is flow of injected fluids (or displacement of formation fluids due to injection) through the formation matrix during or after a hydraulic fracturing treatment. In deep, low-permeability shale and tight gas settings and where induced fractures are contained within the production zone, flow through the production formation has generally been considered an unlikely pathway for migration into drinking water resources (Jackson et al., 2013c). However, there is limited information available on the fate of injected fluids that are not recovered during production (i.e., leakoff) or displaced formation fluids for cases where hydraulic fracturing takes place within or close to drinking water resources.

Leakoff into shale gas formations may be as high as 90% or more of the injected volume (see Section 7.2 and Table 7-2). The actual amount of leakoff depends on the amount of injected fluid, the hydraulic properties of the reservoir (e.g., permeability), the capillary pressure near the fracture faces, and the period of time the well is shut in following hydraulic fracturing before the start of production (Kim et al., 2014; Byrnes, 2011).[1,2] However, despite the potentially large volume of fluid that may be lost into the formation, the flow of this fluid is generally controlled or limited by processes such as imbibition by capillary forces and adsorption onto clay minerals (Dutta et al., 2014; Dehghanpour et al., 2013; Dehghanpour et al., 2012; Roychaudhuri et al., 2011).[3] It has been suggested that these processes can sequester the fluids in the producing formations permanently or for geologic time scales (Engelder, 2012; Byrnes, 2011).

A limited number of studies in the literature have evaluated a combination of certain conditions that can facilitate migration of fluids despite these processes. Myers (2012b) suggests that migration of injected and/or formation fluids into the overburden may be possible in cases where there is a significant vertical hydraulic gradient, sufficient permeability, density-driven buoyancy, and the displacement of formation brines by large volumes of injected fluid. Flewelling and Sharma (2014) note that, for migration to occur, an upward hydraulic gradient would be necessary, particularly for brine that is denser than the ground water in the overlying formations; in the case of natural gas, though, buoyancy would provide an upward flux A limited number of studies in the literature have evaluated a combination of certain conditions that can facilitate migration of fluids despite these processes. Myers (2012b) suggests that migration of injected and/or formation fluids into the overburden may be possible in cases where there is a significant vertical hydraulic gradient, sufficient permeability, density-driven buoyancy, and the displacement of formation

[1] Relative permeability is a dimensionless property allowing for the comparison of the different abilities of fluids to flow in multiphase settings. If a single fluid is present, its relative permeability is equal to 1, but the presence of multiple fluids generally inhibits flow and decreases the relative permeability (Schlumberger, 2014).
[2] Shutting in the well after fracturing allows fluids to move farther into the formation, resulting in a higher gas relative permeability near the fracture surface and improved gas production (Bertoncello et al., 2014).
[3] Imbibition is the displacement of a nonwetting fluid (i.e., gas) by a wetting fluid (typically water). The terms wetting or nonwetting refer to the preferential attraction of a fluid to the surface. In typical reservoirs, water preferentially wets the surface, and gas is nonwetting. Capillary forces arise from the differential attraction between immiscible fluids and solid surfaces; these are the forces responsible for capillary rise in small-diameter tubes and porous materials. These definitions are adapted from Dake (1978).

brines by large volumes of injected fluid. Flewelling and Sharma (2014) note that for migration to occur, an upward hydraulic gradient would be necessary, particularly for brine that is denser than the ground water in the overlying formations; in the case of natural gas, though, buoyancy would provide an upward flux (Vengosh et al., 2014). Some natural conditions could create this upward hydraulic gradient in the absence of any effects from hydraulic fracturing (Flewelling and Sharma, 2014). However, these natural mechanisms have been found to cause very low flow rates over very long distances, yielding extremely small vertical fluxes in sedimentary basins—corresponding to some estimated travel times of 100,000 to 100,000,000 years across a 328 ft (100 m) thick layer with about 0.01 nD (1×10^{-23} m^2) permeability (Flewelling and Sharma, 2014). Furthermore, fracturing fluid would likely be sequestered in the immediate vicinity of the fracture network due to capillary tension (Engelder, 2012).

Over-pressurization of producing formations due to the injection of large amounts of fluid during hydraulic fracturing may support the upward hydraulic gradient for fluid migration (Myers, 2012b). Myers' modeling results suggest that significant pressure buildup that occurs at the location of fluid injection may not return to pre-hydraulic fracturing levels for up to a year. However, these findings have been disputed in the literature due to certain suggested limitations of the original study (e.g., extensive simplification of the model, lack of accurate characterization of regional flow, misrepresentation of saturation conditions in shale formations), and they have been found to be physically implausible given the hydrogeologic characteristics of actual sedimentary basins (Cohen et al., 2013; Flewelling et al., 2013; Vidic et al., 2013; Saiers and Barth, 2012). Some researchers have also suggested that pressure perturbations due to hydraulic fracturing operations are localized to the immediate vicinity of the fractures, due to the very low permeabilities of shale formations (Flewelling and Sharma, 2014). However, there are emerging studies indicating that pressure impacts of hydraulic fracturing operations may extend farther than the immediate vicinity and may create risk of induced seismicity (Skoumal et al., 2015). Following hydraulic fracturing operations, a large-scale depressurization would be expected over the longer term due to hydrocarbon production, which may counteract any short-term localized pressure effects of hydraulic fracturing during production and cause fluids to flow primarily toward the fracture network (Flewelling and Sharma, 2014).

In responses to these critiques, Myers (2013, 2012a) states that they do not prove his original hypothesis or findings wrong, but instead highlight the need for complex three-dimensional modeling and detailed data collection for improving the understanding of the process and risks to drinking water resources. Myers (2013, 2012a) argues that, given the large volume of hydraulic fracturing operations in formations such as the Marcellus, these formations would have to hold very large volumes of water that would be imbibed into the shale. Furthermore, he notes that migration of these fluids into overlying formations may be facilitated by existing fractures or out-of-zone fracturing (as discussed in the following sections).

6.3.2.2. Fracture Overgrowth out of the Production Zone

Fractures that extend out of the intended production zone into another formation or an unintended zone within the same formation could provide a potential fluid migration pathway into drinking water resources (Jackson et al., 2013c). This migration could occur either through the fractures themselves or in connection with other permeable subsurface features or formations (see Figure 6-5). Such “out-of-zone fracturing” is undesirable from a production standpoint and may occur as a result of inadequate reservoir characterization or fracture treatment design (Eisner et al., 2006). Some researchers have noted that fractures growing out of the targeted production zone could potentially contact other formations, such as higher conductivity sandstones or conventional hydrocarbon reservoirs, which may create an additional pathway for potential migration into a drinking water resource (Reagan et al., 2015). In addition, fractures growing out of the production zone could potentially intercept natural, preexisting fractures (discussed in Section 6.3.2.4) or active or abandoned wells near the well where hydraulic fracturing is performed (discussed in Section 6.3.2.3).

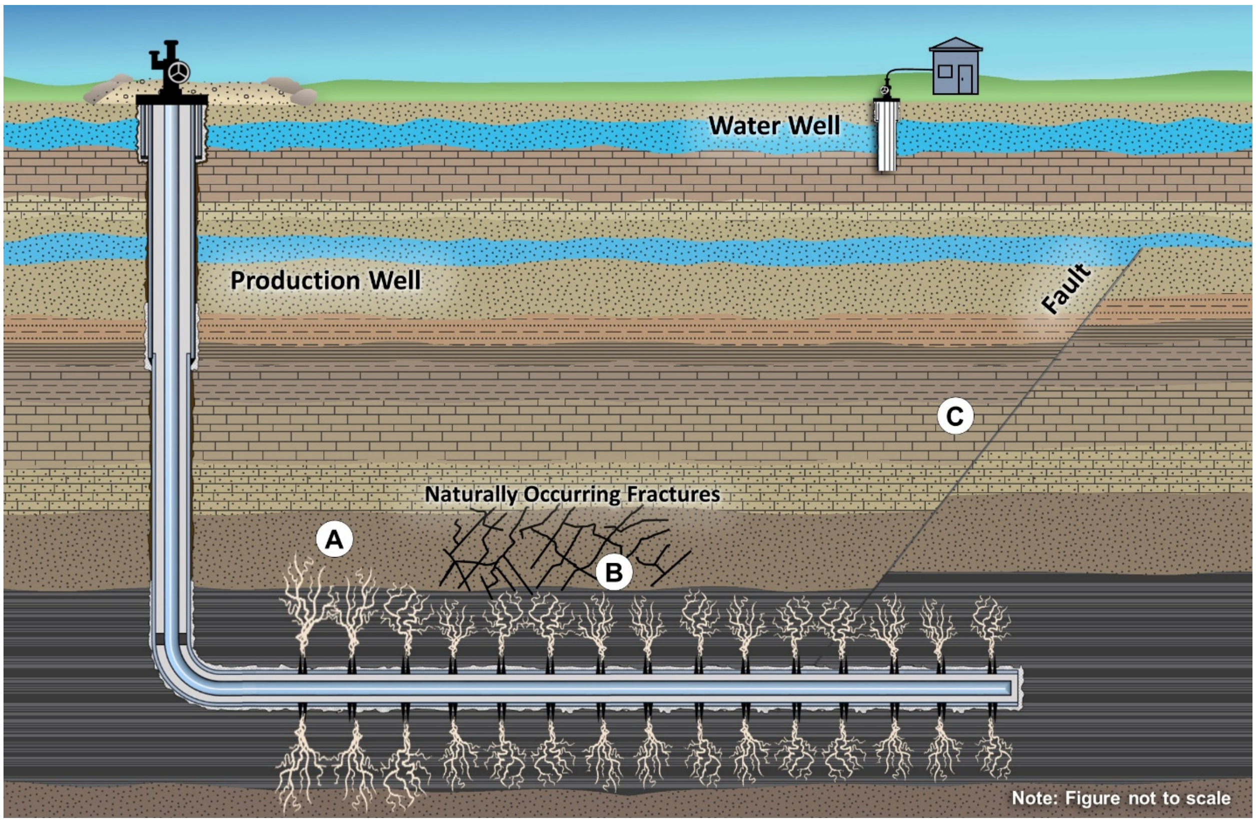

Figure 6-5. Conceptualized depiction of potential pathways for fluid movement out of the production zone: (a) induced fracture overgrowth into over- or underlying formations; (b) induced fractures intersecting natural fractures; and (c) induced fractures intersecting a transmissive fault.

Thickness and depth of production formation are important site specific factors for each operation.

The fracture’s geometry (see Section 6.3.1) affects its potential to extend beyond the intended zone and serve as a pathway to drinking water resources. Vertical heights of fractures created during hydraulic fracturing operations have been measured in several U.S. shale plays, including the Barnett, Woodford, Marcellus, and Eagle Ford, using microseismic and microdeformation field monitoring techniques (Fisher and Warpinski, 2012). These data indicate typical fracture heights extending from tens to hundreds of feet. Davies et al. (2012) analyzed this data set and found that the maximum fracture height was 1,929 ft (588 m) and that 1% of the fractures had a height greater than 1,148 ft (350 m). This may raise some questions about fractures being contained within the producing formation, as some Marcellus fractures were found to extend for at least 1,500 ft (477 m), while the maximum thickness of the formation is generally 350 ft (107 m) or less (MCOR, 2012). However, the majority of fractures were found to have heights less than 328 ft (100 m), suggesting limited possibilities for fracture overgrowth exceeding the separation between shale reservoirs and shallow aquifers (Davies et al., 2012). This is consistent with modeling results found by Kim and Moridis (2015) and others, as described below. Where the producing formation is not continuous horizontally, the lateral extent of fractures may also become important. For example, in the Fisher and Warpinski (2012) data set, fractures were found to extend to horizontal lengths greater than 1,000 ft (305 m).

Results of National Energy Technology Laboratory (NETL) research in Greene County, Pennsylvania, are generally consistent with those reported in the Fisher and Warpinski (2012) data set. Microseismic monitoring was used at six horizontal Marcellus Shale wells to identify the maximum upward extent of brittle deformation caused by hydraulic fracturing (Hammack et al., 2014). At three of the six wells, fractures extending between 1,000 and 1,900 ft (305 and 579 m) above the Marcellus Shale were identified. Overall, approximately 40% of the microseismic events occurred above the Tully Limestone, the formation overlying the Marcellus Shale that is sometimes referred to as an upper barrier to hydraulic fracture growth. However, all microseismic events were at least 5,000 ft (1,524 m) below drinking water aquifers, as the Marcellus Shale is one of the deepest target formations (see Table 6-2), and no impacts to drinking water resources or another local gas-producing interval were identified. See Text Box 6-3 for more information on the Greene County site.

Similarly, in Dunn County, North Dakota, there is evidence of out-of-zone fracturing in the Bakken Shale (U.S. EPA, 2015j). At the Killdeer site (see Section 6.2.2.1 and Chapter 5, Text Box 5-12), fracturing fluids and produced water were released during a rupture of the casing at the Franchuk 44-20 SWH well. Water quality characteristics at two monitoring wells located immediately downgradient of the Franchuk well reflected a mixing of local Killdeer Aquifer water with deep formation brine. Ion and isotope ratios used for brine fingerprinting suggest that Madison Group formations (which directly overlie the Bakken in the Williston Basin) were the source of the brine observed in the Killdeer Aquifer, and the authors concluded that this provides evidence for out-of-zone fracturing. Industry experience also indicates that out-of-zone fracturing may be fairly common in the Bakken and that produced water from many Bakken wells has Madison Group chemical signatures (Arkadakskiy and Rostron, 2013b, 2012b; Peterman et al., 2012).

Text Box 6-3. Monitoring at the Greene County, Pennsylvania, Hydraulic Fracturing Test Site.

Monitoring performed at the Marcellus Shale test site in Greene County, Pennsylvania, evaluated fracture height growth and zonal isolation during and after hydraulic fracturing operations (Hammack et al., 2014). The site has six horizontally drilled and two vertical wells that were completed into the Marcellus Shale. Pre-fracturing studies of the site included a 3D seismic survey to identify faults, pressure measurements, and baseline sampling for isotopes; drilling logs were also run. Hydraulic fracturing occurred April 24 to May 6, 2012, and June 4 to 11, 2012. Monitoring at the site included the following:

- **Microseismic monitoring** was conducted during four of the six hydraulic fracturing jobs on the site, using geophones placed in the two vertical Marcellus Shale wells. These data were used to monitor fracture height growth above the six horizontal Marcellus Shale wells during hydraulic fracturing.
- **Pressure and production data** were collected from a set of vertical gas wells completed in Upper Devonian/Lower Mississippian zones 3,800 to 6,100 ft (1,158 to 1,859 m) above the Marcellus. Data were collected during and after the hydraulic fracturing jobs and used to identify any communication between the fractured areas and the Upper Devonian/Lower Mississippian rocks.
- **Chemical and isotopic analyses** were conducted on gas and water produced from the Upper Devonian/Lower Mississippian wells. Samples were analyzed for stable isotope signatures of hydrogen, carbon, and strontium and for the presence of perfluorocarbon tracers used in 10 stages of one of the hydraulic fracturing jobs to identify possible gas or fluid migration to overlying zones (Sharma et al., 2014a; Sharma et al., 2014b).

As of September 2014, no evidence was found of gas or brine migration from the Marcellus Shale (Hammack et al., 2014), although longer-term monitoring will be necessary to confirm that no impacts to overlying zones have occurred (Zhang et al., 2014a).

Extreme vertical fracture growth is generally considered to be limited by layered geological environments and other physical constraints (Fisher and Warpinski, 2012; Daneshy, 2009). For example, differences in in situ stresses in layers above and below the production zone can restrict fracture height growth in sedimentary basins (Fisher and Warpinski, 2012). High-permeability layers near hydrocarbon-producing zones can reduce fracture growth by acting as a "thief zone" into which fluids can migrate, or by inducing a large compressive stress that acts on the fracture (de Pater and Dong, 2009, as cited in Fisher and Warpinski, 2012). Although these thief zones may prevent fractures from reaching shallower formations or growing to extreme vertical lengths, it is important to note that they do allow fluids to migrate out of the production zone into these receiving formations, which could potentially contain drinking water resources. A volumetric argument has also been used to discuss limits of vertical fracture growth; that is, the volumes of fluid needed to sustain fracture growth beyond a certain height would be unrealistic (Fisher and Warpinski, 2012). However, as described in Section 6.3.1, fracture volume can be greater than the volume of injected fluid due to the effects of pressurized water combined with the effects of gas during injection (Kim and Moridis, 2015). Nevertheless, some numerical investigations suggest that, unless unrealistically high pressures and injection rates are applied to an extremely weak and homogeneous formation that extends up to the near surface, hydraulic fracturing generally induces stable and finite fracture growth in a Marcellus-type environment and the fractures are unlikely to extend into drinking water resources (Kim and Moridis, 2015).

Modeling studies have identified other factors that affect the containment of fractures within the producing formation. As discussed above, additional numerical analysis of fracture propagation during hydraulic fracturing has demonstrated that contrasts in the geomechanical properties of rock formations can affect fracture height containment (Gu and Siebrits, 2008) and that geological layers present within shale gas reservoirs can limit vertical fracture propagation (Kim and Moridis, 2015). Modeling and monitoring studies generally agree that physical constraints on fracture propagation will prevent induced fractures from extending from deep zones directly into drinking water resources (Kim and Moridis, 2015; Flewelling et al., 2013; Fisher and Warpinski, 2012).

Using a numerical simulation, Reagan et al. (2015) investigated potential short-term migration of gas and water between a shale or tight gas formation and a shallower ground water unit. Migration was assessed immediately after hydraulic fracturing and for up to a 2-year time period during the production stage. The potential migration pathway was assumed to be a permeable fracture or fault connecting the producing formation to the shallower ground water unit. Such a pathway may be either entirely hydraulically induced (due to fracture overgrowth in a case where the separation distance is limited, as discussed below), or may be a smaller induced fracture connecting to a natural, permeable fault or fracture (as discussed in Section 6.3.2.4). For the purposes of this study, the pathway was assumed to be pre-existing, and Reagan et al. (2015) did not model the fracturing process itself.

The subsurface system evaluated in the modeling investigation included a horizontal well used for hydraulic fracturing and gas production, the connecting fracture or fault between the producing formation and the aquifer, and a shallow vertical water well in the aquifer (see Figure 6-5). The parameters and scenarios used in the study are shown in Table 6-3; two vertical separation distances between the producing formation and the aquifer were investigated, along with a range of production zone permeabilities and other variables used to describe four production scenarios. The horizontal well was assigned a constant bottomhole pressure of half the initial pressure of the target reservoir, not accounting for any over-pressurization from hydraulic fracturing. Over-pressurization during hydraulic fracturing may create an additional driving force for upward migration. Results of this investigation, which represents a typical production period, indicate a generally downward water flow within the connecting fracture (from the aquifer through the connecting fracture into the hydraulically induced fractures in the production zone) and some upward migration of gas (Reagan et al., 2015). In certain cases, gas breakthrough (i.e., the appearance of gas at the base of the drinking water aquifer) was also observed. The key parameter affecting migration of gas into the aquifer was the production regime, particularly whether gas production, driving the fluid migration toward the production well, was occurring in the reservoir. Simulations including a producing gas well showed only a few instances of breakthrough, while simulations without gas production tended to result in breakthrough; these breakthrough times ranged from minutes to 20 days. However, in all cases, the gas escape was limited in duration and scope, because the amount of gas available for immediate migration toward the shallow aquifer was limited to that initially stored in the hydraulically induced fractures after the stimulation process and prior to production. These simulations indicate that the target reservoir may not be able to replenish the gas available for migration in hydraulically induced fractures prior to production.

Table 6-3. Modeling parameters and scenarios investigated by Reagan et al. (2015).

This table illustrates the range of parameters included in the Reagan et al. (2015) modeling study. See Figure 6-5, Figure 6-6, and Figure 6-7 for conceptualized illustrations of these scenarios.

Model parameter or variable	Values investigated in model scenarios
All scenarios	
Lateral distance from connecting feature to water well	328 ft (100 m)
Vertical separation distance between producing formation and drinking water aquifer	656 ft (200 m); 2,625 ft (800 m)
Producing formation permeability range	1 nD (1 x 10^{-21} m^2); 100 nD (1 x 10^{-19} m^2); 1 µD (1 x 10^{-18} m^2)
Drinking water aquifer permeability	0.1 D (1 x 10^{-13} m^2); 1 D (1 x 10^{-12} m^2)
Initial conditions	Hydrostatic
Production well bottom hole pressure	Half of the initial pressure of the producing formation (not accounting for over-pressurization from hydraulic fracturing)
Production regime	Production at both the water well and the gas well; Production at only the water well; Production at only the gas well; No production
Fracture pathway scenarios	
Connecting feature permeability	1 D (1 x 10^{-12} m^2); 10 D (1 x 10^{-11} m^2); 1,000 D (1 x 10^{-9} m^2)
Offset well pathway scenarios	
Lateral distance from production well to offset well	33 ft (10 m)
Cement permeability of offset well	1 µD (1 x 10^{-18} m^2); 1 mD (1 x 10^{-15} m^2); 1 D (1 x 10^{-12} m^2); 1,000 D (1 x 10^{-9} m^2)

Based on the results of the Reagan et al. (2015) study, gas production from the reservoir appears likely to mitigate gas migration, both by reducing the amount of available gas and depressurizing the induced fractures (which counters the buoyancy of any gas that may escape from the production zone into the connecting fracture). Production at the gas well also creates pressure gradients that drive a downward flow of water from the aquifer via the fracture into the producing formation, increasing the amount of water produced at the gas well. Furthermore, the effective permeability of the connecting feature is reduced during water (downward) and gas (upward) counter-flow within the fracture, further retarding the upward movement of gas or allowing gas to dissolve into the downward flow. In contrast, Reagan et al. (2015) found an increased potential for gas release from the producing formation in cases where there is no gas production following hydraulic fracturing. The potential for gas migration during shut-in periods following hydraulic fracturing and prior to production may be more significant, especially when out-of-zone fractures are formed. Without the producing gas well, the gas may rise via buoyancy, with any downward-flowing water from the aquifer displacing the upward-flowing gas.

Reagan et al. (2015) also found that the permeability of a connecting fault or fracture may be an important factor for the potential upward migration of gas (although not as significant as the production regime). For the cases where gas escaped from the production zone, the maximum amount of migrating gas depended upon the permeability of the connecting feature: the higher the permeability, the larger the amount. The results also showed that lower permeabilities delay the downward flow of water from the aquifer, allowing the trace amount of gas that entered into the fracture early in the modeled period to reach the aquifer, which was otherwise predicted to dissolve in the water flowing downward in the feature. Similarly, the permeabilities of the target reservoir, fracture volume, and the separation distance were found to affect gas migration, because they affected the initial amount of gas stored in the hydraulically induced fractures. In contrast, the permeability of the drinking water aquifer was not found to be a significant factor in their assessment.

6.3.2.3. Migration via Fractures Intersecting with Offset Wells and Other Artificial Structures

Another potential pathway for fluid migration is one in which injected fluids or displaced subsurface fluids move through newly created fractures into an offset well or its fracture network, resulting in well communication (Jackson et al., 2013c). This may be a concern, particularly in shallower formations where the local least principal stress is vertical (resulting in more horizontal fracture propagation) and where there are shallow drinking water wells in the same formation.

The offset well can be an abandoned, inactive, or active well; if the well has also been used for hydraulic fracturing, the fracture networks of the two wells might intersect. The situation where hydraulic fractures unintentionally propagate into other existing, producing hydraulic fractures is referred to as a “frac hit” and is known to occur in areas with a high density of wells (Jackson et al., 2013a). Figure 6-6 provides a schematic to illustrate fractures that intercept an offset well, and Figure 6-7 depicts how the fracture networks of two wells can intersect.

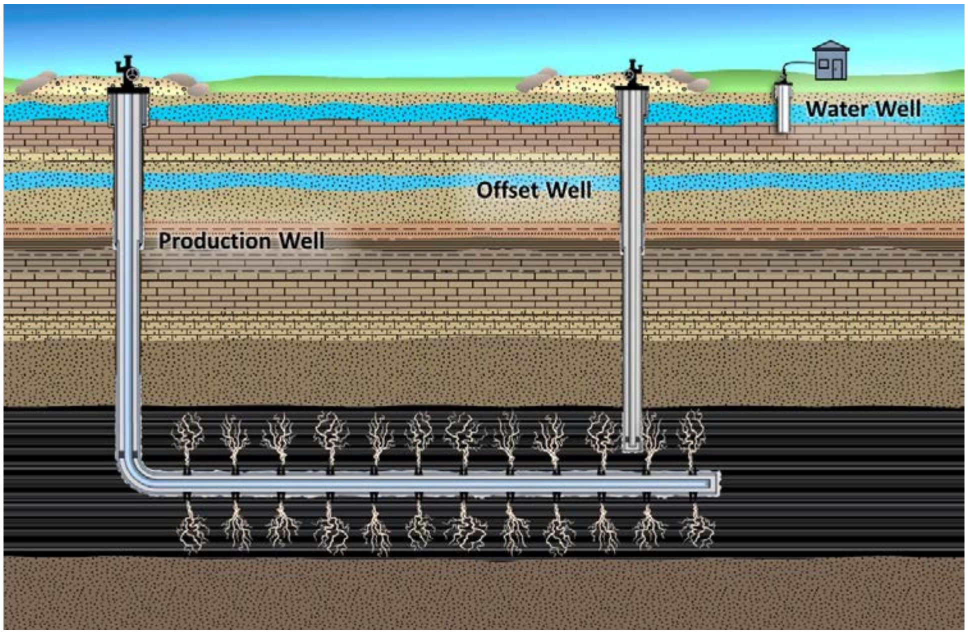

Figure 6-6. Induced fractures intersecting an offset well (in a production zone, as shown, or in overlying formations into which fracture growth may have occurred).

This image shows a conceptualized depiction of potential pathways for fluid movement out of the production zone (not to scale).

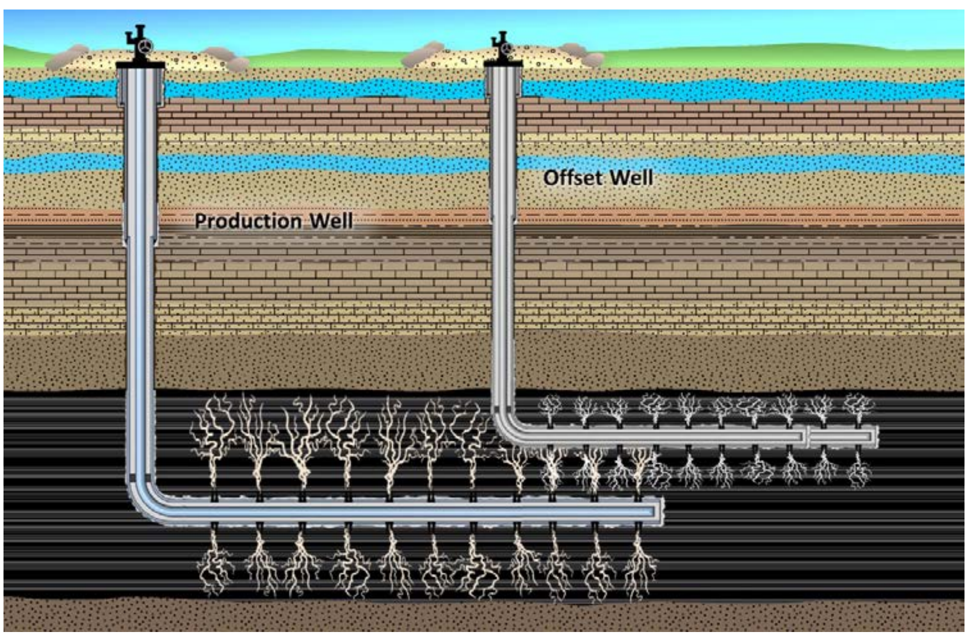

Figure 6-7. Well communication (a frac hit) via induced fractures intersecting another well or its fracture network.

This image shows a conceptualized depiction of potential pathways for fluid movement out of the production zone (not to scale).

Instances of well communication have been known to occur and are described in the oil and gas literature. For example, an analysis of operator data collected by the New Mexico Oil Conservation Division (NM OCD) in 2013−2014 identified 120 instances of well communication in the San Juan Basin (Vaidyanathan, 2014). In some cases, well communication incidents have led to documented production and/or environmental problems. A study from the Barnett Shale noted two cases of well communication, one with a well 1,100 ft (335 m) away and the other with a well 2,500 ft (762 m) away from the initiating well; ultimately, one of the offset wells had to be re-fractured because the well communication halted production (Craig et al., 2012). In some cases, the fluids that intersect the offset well flow up the wellbore and spill onto the surface. The EPA (2015n) recorded 10 incidents in which fluid spills were attributed to well communication events (see Chapter 7 for more information).[1] The subsurface effects of frac hits have not been extensively studied, but these cases demonstrate the possibility of fluid migration via communication with other wells and/or their fracture networks. More generally, well communication events may indicate fracture behavior that was not intended by the treatment design.

A well communication event is usually observed at the offset well as a pressure spike, due to the elevated pressure from the originating well, or as an unexpected drop in the production rate (Lawal et al., 2014; Jackson et al., 2013a). Ajani and Kelkar (2012) performed an analysis of frac hits in the Woodford Shale in Oklahoma, studying 179 wells over a 5-year period. The authors used fracturing records from the newly completed wells and compared them to production records from surrounding wells. The authors assumed that sudden changes in production of gas or water coinciding with fracturing at a nearby well were caused by communication between the two wells, and increased water production at the surrounding wells was assumed to be caused by fracturing fluid flowing into these offset wells. The results of the Oklahoma study showed that 24 wells had decreased gas production or increased water production within 60 days of the initial gas production at the nearby fractured well. A total of 38 wells experienced decreased gas or increased water production up to a distance of 7,920 ft (2,414 m), measured as the distance between the midpoints of the laterals; 10 wells saw increased water production from as far away as 8,422 ft (2,567 m). In addition, one well showed a slight increase in gas production rather than a decrease.[2]

Other studies of well communication events have relied on similar information. In the NM OCD operator data set, the typical means of detecting a well communication event was through pressure changes at the offset well, production lost at the offset well, or fluids found in the offset well. In some instances, well operators determined that a well was producing fluid from two different formations, while in one instance, the operator identified a potential well communication event due to an increase in production from the offset well (Vaidyanathan, 2014). In another study, Jackson et al. (2013a) found that the decrease in production due to well communication events was much greater in lower permeability reservoirs. The authors note an example where two wells 1,000 ft (305 m) apart communicated, reducing production in the offset well by 64%. These results indicate that the subsurface interactions of well networks or complex hydraulics driven by each well at a

[1] Line numbers 163, 236, 265, 271, 286, 287, 375, 376, 377, and 380 in Appendix B of U.S. EPA (2015n).
[2] The numbers of wells cited in the study reflect separate analyses, and the numbers cited are not additive.

densely populated (with respect to wells) area are important factors to consider for the design of hydraulic fracturing treatments and other aspects of oil and gas production.

The key factor affecting the likelihood of a well communication event and the impact of a frac hit is the location of the offset well relative to the well where hydraulic fracturing was conducted (Ajani and Kelkar, 2012). In the Ajani and Kelkar (2012) analysis, the likelihood of a communication event was less than 10% in wells more than 4,000 ft (1,219 m) apart, but rose to nearly 50% in wells less than 1,000 ft (305 m) apart. Well communication was also much more likely with wells drilled from the same pad. The affected wells were found to be in the direction of maximum horizontal stress in the field, which correlates with the expected direction of fracture propagation.

Well communication may be more likely to occur where there is less resistance to fracture growth. Such conditions may be related to existing production operations (e.g., where previous hydrocarbon extraction has reduced the pore pressure, changed stress fields, or affected existing fracture networks) or the existence of high-permeability rock units (Jackson et al., 2013a). As Ajani and Kelkar (2012) found in the Woodford Shale, one of the deepest major shale plays (see Table 6-2), hydraulic fracturing treatments tend to enter portions of the reservoir that have already been fractured as opposed to entering previously unfractured rocks, ultimately causing interference in offset wells. Mukherjee et al. (2000) described this tendency for asymmetric fracture growth toward depleted areas in low-permeability gas reservoirs due to pore pressure depletion from production at offset wells. The authors note that pore pressure gradients in depleted zones would affect the subsurface stresses. Therefore, depending on the location of the new well with respect to depleted zone(s) and the orientation of the existing induced fractures, the newly created fracture may be asymmetric, with only one wing of the fracture extending into the depleted area and developing significant length and conductivity (Mukherjee et al., 2000). The extent to which the depleted area affects fracturing depends on factors such as cumulative production, pore volume, hydrocarbon saturation, effective permeability, and the original reservoir or pore pressure (Mukherjee et al., 2000). Similarly, high-permeability rock types acting as thief zones may also cause preferential fracturing due to a higher leakoff rate into these layers (Jackson et al., 2013a).

In addition to location, the potential for impact on a drinking water resource also depends on the condition of the offset well (see Section 6.2 for information on the integrity of well components). In their analysis, Ajani and Kelkar (2012) found a correlation between well communication and well age: older wells were more likely to be affected. If the cement in the annulus between the casing and the formation is intact and the well components can withstand the stress exerted by the pressure of the fluid, nothing more than an increase in pressure and extra production of fluids may occur during a well communication event. However, if the offset well is not able to withstand the pressure of the fracturing fluid, well components may fail, allowing fluid to migrate out of the well. The highest pressures most wells will face during their life spans occur during fracturing. In some cases, temporary equipment is installed in wells during fracturing to protect the well against the increased pressure. Therefore, many producing wells may not be designed to withstand pressures typical of hydraulic fracturing (Enform, 2013) and may experience problems when fracturing occurs in nearby wells. Depending on the location of the weakest point in the offset well, this could result in fluid being spilled onto the surface, rupturing of cement and/or casing and hydraulic fracturing fluid leaking into subsurface formations, or fluid flowing out through existing flaws in the casing and/or cement (see Chapters 5 and 7 for additional information on how such spills can affect drinking water resources). For example, a documented well communication event near Innisfail, Alberta, Canada (see Text Box 6-4) occurred when several well components failed because they were not rated to handle the increased pressure caused by the well communication (ERCB, 2012). In addition, if the fractures were to intersect an uncemented portion of the wellbore, the fluids could potentially migrate into any formations that are uncemented along the wellbore.

Text Box 6-4. Well Communication at a Horizontal Well near Innisfail, Alberta, Canada.

In most cases, well communication during fracturing may only result in a pressure surge accompanied by a drop in gas production and additional flow of produced water or fracturing fluid at an offset well. However, if the offset well is not capable of withstanding the high pressures of fracturing, more significant damage can occur.

In January 2012, fracturing at a horizontal well near Innisfail in Alberta, Canada, caused a surface spill of fracturing and formation fluids at a nearby operating vertical oil well. According to the investigation report by the Alberta Energy Resources Conservation Board (ERCB, 2012), pressure began rising at the vertical well less than two hours after fracturing ended at the horizontal well.

Several components of the vertical well facility—including surface piping, discharge hoses, fuel gas lines, and the pressure relief valve associated with compression at the well—were not rated to handle the increased pressure and failed. Ultimately, the spill released an estimated 19,816 gallons (75 m^3) of fracturing fluid, brine, gas, and oil covering an area of approximately 656 ft by 738 ft (200 m by 225 m).

The ERCB determined that the lateral of the horizontal well passed within 423 ft (129 m) of the vertical well at a depth of approximately 6,070 ft (1,850 m) below the surface, in the same formation. The operating company had estimated a fracture half-length of 262 to 295 ft (80 to 90 m) based on a general fracture model for the field. While there were no regulatory requirements for spacing hydraulic fracturing operations in place at the time, the 423 ft (129 m) distance was out of compliance with the company's internal policy to space fractures from adjacent wells at least 1.5 times the predicted half-length. The company also did not notify the operators of the vertical well of the fracturing operations. The incident prompted the ERCB to issue *Bulletin 2012-02—Hydraulic Fracturing: Interwellbore Communication between Energy Wells*, which outlines expectations for avoiding well communication events and preventing adverse effects on offset wells.

In older wells near a hydraulic fracturing operation, plugs and cement may have degraded over time; in some cases, abandoned wells may never have been plugged properly. Before the 1950s, most well plugging efforts were focused on preventing water from the surface from entering oil fields. As a result, many wells from that period were abandoned with little or no cement (NPC, 2011b). This can be a significant issue in areas with legacy (i.e., historic) oil and gas exploration and when wells are re-entered and fractured (or re-fractured) to increase production in a reservoir. In one study, 18 of 29 plugged and abandoned wells in Quebec were found to show signs of leakage (Council of Canadian Academies, 2014). Similarly, a PA DEP report cited three cases where natural gas migration had been caused by well communication events with old, abandoned wells (PA DEP, 2009b). The Interstate Oil and Gas Compact Commission (IOGCC, 2008) estimates that over 1 million wells may have been drilled in the United States prior to a formal regulatory system, and the status and location of many of these wells are unknown. Various state programs exist to plug identified orphaned wells, but they face the challenge of identifying and addressing a large number of wells.[1] For example, as of 2000, PA DEP's well plugging program reported that it had documented 44,700 wells that had been plugged and 8,000 that were in need of plugging, and approximately 184,000 additional wells with an unknown location and status (PA DEP, 2000). A similar evaluation from New York State found that the number of unplugged wells was growing in the state despite an active well plugging program (Bishop, 2013).

The Reagan et al. (2015) numerical modeling study included an assessment of migration via an offset well as part of its investigation of potential fluid migration from a producing formation into a shallower ground water unit (see Section 6.3.2.2). In the offset well pathway, it was assumed that the hydraulically induced fractures intercepted an older offset well with deteriorated components. (This assessment can also be applicable to cases where potential migration may occur via the production well-related pathways discussed in Section 6.2.) More specifically, this analysis was designed to assess transport through deteriorating cement between the subsurface formations and the outermost casing, through voids resulting from incomplete cement coverage, through breached tubing, or in simpler well installations without multiple casings. The highest permeability value tested for the connecting feature represented a case with an open wellbore. A key assumption for this investigation was that the offset well was already directly connected to a permeable feature in the reservoir or within the overburden. Similar to the cases for permeable faults or fractures discussed in the previous section, the study investigated the effect of multiple well- and formation-related variables on potential fluid migration (see Table 6-3).

Based on the simulation results, an offset well pathway may have a greater potential for gas release from the production zone into a shallower ground water unit than the fault/fracture pathway discussed in Section 6.3.2.2 (Reagan et al., 2015). This difference is primarily due to the total pore volume of the connecting pathway within the offset well; the offset well pathway may have a significantly lower pore volume compared to the fault/fracture pathway, which reduces possible gas storage in the connecting feature and increases the speed of buoyancy-dependent migration. However, as with the fault/fracture scenario, the gas available for migration in this case is still limited to the gas that is initially stored in the hydraulically induced fractures. Therefore, any incidents of gas breakthrough observed in this study were found to be limited in both duration and magnitude.

Reagan et al. (2015) found that production at the gas well (the well used for hydraulic fracturing) also affects the potential upward migration of gas and its arrival times at the drinking water formation due to its effect on the driving forces (e.g., pressure gradient). Similar to the fault/fracture cases described in Section 6.3.2.2, production in the target reservoir appears to mitigate upward gas migration, both by reducing the amount of gas that might otherwise be

[1] An orphaned well is an inactive oil or gas well with no known (or financially solvent) owner.

available for upward migration and creating a pressure gradient toward the production well. Only scenarios without the mitigating feature of gas production result in any upward migration into the aquifer. This assessment also found a generally downward water flow within the connecting well pathway, which is more pronounced when the gas well is operating. The producing formation and aquifer permeabilities appear not to be significant factors for upward gas migration via this pathway. In addition, Reagan et al. (2015) found the permeability of the connecting offset well to be one of the main factors affecting the migration of gas to the aquifer and the water well. Very low permeabilities (less than 1 mD) lead to no migration of gas into the aquifer regardless of the vertical separation distance, whereas larger permeabilities present a greater potential for gas breakthrough.

In the same way that fractures can propagate to intersect offset wells, they can also potentially intersect other artificial subsurface structures including mine shafts or solution mining sites. No known incidents of this type of migration have been documented. However, the Bureau of Land Management (BLM) has identified over 28,000 abandoned mines in the United States and is adding new mines to its inventory every year (BLM, 2013a). In addition, the Well File Review identified an estimated 800 cases where wells used for hydraulic fracturing were drilled through mining voids, and an additional 90 cases of drilling through gas storage zones or wastewater disposal zones (U.S. EPA, 2015o). The analysis suggests that emplacing cement within such zones may be challenging, which, in turn, could lead to a loss of zonal isolation (as described in Section 6.2) and create a pathway for fluid migration.

6.3.2.4. Migration via Fractures Intersecting Geologic Features

Potential fluid migration via natural fault or fracture zones in conjunction with hydraulic fracturing has been recognized as a potential contamination hazard for several decades (Harrison, 1983). While porous flow in unfractured shale or tight sand formations is assumed to be negligible due to very low formation permeabilities (as discussed in Section 6.3.2.1), the presence of natural "microfractures" within tight sand or shale formations is widely recognized, and these fractures affect fluid flow and production strategies. Naturally occurring permeable faults and larger scale fractures within or between formations may allow for more significant flow pathways for migration of fluids out of the production zone (Jackson et al., 2013c; Myers, 2012a). Figure 6-4 illustrates the concept of induced fractures intersecting with natural faults or fractures extending out of the target reservoir.

Natural fracture systems have a strong influence on the success of a fracture treatment, and the topic has been studied extensively from the perspective of optimizing treatment design (e.g., Weng et al., 2011; Dahi Taleghani and Olson, 2009; Vulgamore et al., 2007). Small natural fractures, known as "microfractures," could affect fluid flow patterns near the induced fractures by increasing the effective contact area. Conversely, the natural microfractures could act as capillary traps for the fracturing fluid during treatment (contributing to fluid leakoff) and potentially hinder hydrocarbon flow due to lower gas relative permeabilities (Dahi Taleghani et al., 2013). Rutledge and Phillips (2003) suggested that, for a hydraulic fracturing operation in East Texas, pressurizing existing fractures (rather than creating new hydraulic fractures) may be the primary process that controls enhanced permeability and fracture network conductivity at the site. Ciezobka and Salehi (2013) used microseismic data to investigate the effects of natural fractures in the Marcellus Shale and concluded that fracture treatments are more efficient in areas with clusters or "swarms" of small natural fractures, while areas without these fracture swarms require more thorough stimulation. However, there is very little attention given in the literature to studying unintended fluid migration during hydraulic fracturing operations due to existing microfractures.

In some areas, larger-scale geologic features may affect potential fluid flow pathways. As discussed in Text Box 6-2, baseline measurements taken before shale gas development show evidence of thermogenic methane in some shallow aquifers, suggesting that natural subsurface pathways exist and allow for naturally occurring migration of gas over millions of years (Robertson et al., 2012). There is also evidence demonstrating that gas undergoes mixing in subsurface pathways (Baldassare et al., 2014; Molofsky et al., 2013; Fountain and Jacobi, 2000). Warner et al. (2012) compared recent sampling results to data published in the 1980s and found geochemical evidence for migration of fluids through natural pathways between deep underlying formations and shallow aquifers—pathways that the authors suggest could lead to contamination from hydraulic fracturing activities. In northeastern Pennsylvania, there is evidence that brine from deep saline formations has migrated into shallow aquifers over geologic time, preferentially following certain geologic structures (Llewellyn, 2014). As described in Chapter 7, karst features (created by the dissolution of soluble rock) can also serve as a potential pathway of fluid movement on a faster time scale.

Monitoring data show that the presence of natural faults and fractures can affect both the height and width of hydraulic fractures. When faults are present, relatively larger microseismic responses are seen and larger fracture growth can occur, as described below. Concentrated swarms of natural fractures within a shale formation can result in a fracture network with a larger width-to-height ratio (i.e., a shorter and wider network) than would be expected in a zone with a low degree of natural fracturing (Ciezobka and Salehi, 2013).

A few studies have used monitoring data to specifically investigate the effect of natural faults and fractures on the vertical extent of induced fractures. A statistical analysis of microseismic data by Shapiro et al. (2011) found that fault rupture from hydraulic fracturing is limited by the extent of the stimulated rock volume and is unlikely to extend beyond the fracture network. (However, as demonstrated by microseismic data presented by Vulgamore et al. (2007), in some settings the fracture network can extend laterally for thousands of feet.) In the Fisher and Warpinski (2012) data set (see Section 6.3.2.2), the greatest fracture heights occurred when the hydraulic fractures intersected pre-existing faults. Similarly, Hammack et al. (2014) reported that fracture growth seen above the Marcellus Shale is consistent with the inferred extent of pre-existing faults at the Greene County, Pennsylvania, research site (see Section 6.3.2.2 and Text Box 6-3). The authors suggested that clusters of microseismic events may have occurred where preexisting small faults or natural fractures were present above the Marcellus Shale. At a site in Ohio, Skoumal et al. (2015) found that hydraulic fracturing induced a rupture along a pre-existing fault approximately 0.6 miles (1 km) from the hydraulic fracturing operation. Using a new monitoring method known as tomographic fracturing imaging, Lacazette and Geiser (2013) also found vertical hydraulic fracturing fluid movement from a production well into a natural fracture network for distances of up to 0.6 miles (1 km). However, Davies et al. (2013) questioned whether this technique actually measures hydraulic fracturing fluid movement.

Modeling studies have also investigated whether hydraulic fracturing operations are likely to reactivate faults and create a potential fluid migration pathway into shallow aquifers. Myers (2012a, 2012b) found that a highly conductive fault could result in rapid (<1 year) fluid migration from a deep shale zone to the surface (as described in Section 6.3.2.1). Other researchers reject the notion that open, permeable faults would coexist with hydrocarbon accumulation (Flewelling et al., 2013), although it is unclear whether the existence of faults in low permeability reservoirs would affect the accumulation of hydrocarbons because, under natural conditions, the flow of gas may be limited due to capillary tension. Results from another recent modeling study suggest that, under specific circumstances, interaction with a conductive fault could result in fluid migration to the surface only on longer (ca. 1,000 year) time scales (Gassiat et al., 2013). Rutqvist et al. (2013) found that, while somewhat larger microseismic events are possible in the presence of faults, repeated events and aseismic slip would amount to a total rupture length of 164 ft (50 m) or less along a fault, not far enough to allow fluid migration between a deep gas reservoir and a shallow aquifer. A follow-up study using more sophisticated three-dimensional modeling techniques also found that deep hydraulic fracturing is unlikely to create a direct flow path into a shallow aquifer, even when fracturing fluid is injected directly into a fault (Rutqvist et al., 2015). Similarly, a modeling study that investigated potential fluid migration from hydraulic fracturing in Germany found potential vertical fluid migration up to 164 ft (50 m) in a scenario with high fault zone permeability, although the authors note this is likely an overestimate because their goal was to “assess an upper margin of the risk” associated with fluid transport (Lange et al., 2013). More generally, results from Rutqvist et al. (2013) indicate that fracturing along an initially impermeable fault (as is expected in a shale gas formation) would result in numerous small microseismic events that act to prevent larger events from occurring (and, therefore, prevent the creation of more extensive potential pathways).

Other conditions in addition to the physical presence of a pathway would need to exist for fluid migration to a drinking water resource to occur. The modeling study conducted by (Reagan et al., 2015) discussed in Section 6.3.2.2 indicates that, if such a permeable feature exists, the transport of gas and fluid flow would strongly depend upon the production regime and, to a lesser degree, the features’ permeability and the separation between the reservoir and the aquifer. In addition, the pressure distribution within the reservoir (e.g., over-pressurized vs. hydrostatic conditions) will affect the fluid flow through fractures/faults. As a result, the presence of multiple natural and well-based factors may increase the potential for fluid migration into drinking water resources. For example, in the Mamm Creek area of Colorado (see Section 6.2.2.2), well integrity and drilling-related problems likely acted in concert with natural fracture systems to result in a gas seep into surface water and shallow ground water (Crescent, 2011).

6.4. Synthesis

In the injection stage of hydraulic fracturing, operators inject fracturing fluids into a well under high pressure. These fluids flow through the well and into the surrounding formation, where they increase pore pressure and create fractures in the rock, allowing hydrocarbons to flow through the fractures and up the well.

The production well and the surrounding geologic features function as a system that is often designed with multiple elements that can isolate hydrocarbon-bearing zones and water-bearing zones, including drinking water resources, from each other. This physical isolation optimizes oil and gas production and can protect drinking water resources via isolation within the well (by the casing and cement) and the presence of multiple layers of subsurface rock between the target formations where hydraulic fracturing occurs and drinking water aquifers.

6.4.1. Summary of Findings

Potential pathways for impacts on drinking water (i.e., the movement of hydrocarbons, formation brines, or other fracturing-related fluids into drinking water resources), may be linked to one or more components of the well and/or features of the subsurface system. If present, these potential pathways can, in combination with the high pressures under which fluids are injected and pressure changes within the subsurface, have an impact on drinking water resources.

The potential for these pathways to exist or form has been investigated through modeling studies that simulate subsurface responses to hydraulic fracturing, and demonstrated via case studies and other monitoring efforts. In addition, the development of some of these pathways—and fluid movement along them—has been documented.

It is important to note that the development of one pathway within this system does not necessarily result in an impact to a drinking water resource. For example, if cracks were to form in the cement of a well, the vertical distance between the production zone and a drinking water resource (and the multiple layers of rock in between) could isolate and protect the drinking water aquifer if pressures were insufficient to allow fluid movement to the level of the drinking water resource. Conversely, if an undetected fault were present in a rock formation, intact cement within the production well could keep fluids from migrating up along the well to the fault and protect drinking water resources.

6.4.1.1. Fluid Movement via the Well

A production well undergoing hydraulic fracturing is subject to higher stresses during the relatively brief hydraulic fracturing phase than during any other period of activity in the life of the well. These higher stresses may contribute to the formation of potential pathways associated with the casing or cement that can result in the unintentional movement of fluids through the production wellbore if the well cannot withstand the stresses experienced during hydraulic fracturing operations (see Section 6.2).

Multiple barriers within the well, including casing, cement, and a completion assembly, isolate hydrocarbon-bearing formations from drinking water resources. However, inadequate construction, defects in or degradation of the casing or cement, or the absence of redundancies such as multiple layers of casing, can allow fluid movement, which can then affect the quality of drinking water resources. Ensuring proper well design and mechanical integrity—particularly proper cement placement and quality—are important actions for preventing unintended fluid migration along the wellbore.

6.4.1.2. Fluid Movement within Subsurface Geologic Formations

Potential subsurface pathways for fluid migration include flow of fluids out of the production zone into formations above or below it, fractures extending out of the production zone or into other induced fracture networks, intersections of fractures with abandoned or active wells, and fractures intersecting with faults or natural fractures (see Section 6.3).

Vertical separation between the production zone where hydraulic fracturing operations occur and drinking water resources, and lateral separation between wells undergoing hydraulic fracturing and other wells can reduce the potential for fluid migration that can impact drinking water resources.

Well communication incidents or "frac hits" have been reported in New Mexico, Oklahoma, and other locations. While some operators design fracturing treatments to communicate with the fractures of another well and optimize production, unintended communication between two fracture systems can lead to spills in the offset well and is an indicator of hydraulic fracturing treatments extending beyond their planned design. Surface spills from well communication incidents have been documented in the literature, which provides evidence for occurrence of frac hits. Based on the available information, frac hits most commonly occur on multi-well pads and when wells are spaced less than 1,100 ft (335 m) apart, but they have been observed at wells up to 8,422 ft (2,567 m) away from a well undergoing hydraulic fracturing.

6.4.1.3. Impacts to Drinking Water Resources

We identified an impact on drinking water resources associated with hydraulic fracturing operations in Bainbridge, Ohio. Failure to cement over-pressured formations through which the production well passed—and proceeding with the fracturing operation without adequate cement and an extended period during which the well was shut in—led to a buildup of natural gas within the well annulus and high pressures within the well. This ultimately resulted in movement of gas from the production zone into local drinking water aquifers (see Section 6.2.2.2).

Casings at a production well near Killdeer, North Dakota, ruptured following a pressure spike during hydraulic fracturing, allowing fluids to escape to the surface. Brine and tert-butyl alcohol were detected in two nearby water wells. Following an analysis of potential sources, the only potential source consistent with the conditions observed in the two impacted wells was the well that ruptured. There is also evidence that out-of-zone fracturing occurred at the well (see Sections 6.2.2.1 and 6.3.2.2).

There are other cases where hydraulic fracturing could be a contributing cause to impacts on drinking water resources, or where the specific mechanism that led to an impact on a drinking water resource cannot be definitively determined. For example:

- Migration of stray gas into drinking water resources involves many potential routes for migration of natural gas, including poorly constructed casing and naturally existing or induced fractures in subsurface formations. Multiple pathways for fluid movement may be working in concert in northeastern Pennsylvania (possibly due to cement issues or sustained casing pressure) and the Raton Basin in Colorado (where fluid migration may have occurred along natural rock features or faulty well seals). While the sources of methane identified in drinking water wells in each study area could be determined with varying degrees of certainty, attempts to definitively identify the pathways of migration have generally been inconclusive (see Text Box 6-2).

- At the East Mamm Creek drilling area in Colorado, inadequate placement of cement allowed the migration of methane through natural faults and fractures in the area. This case illustrates how construction issues, sustained casing pressure, and the presence of natural faults and fractures, in conjunction with elevated pressures associated with well stimulation, can work together to create a pathway for fluids to migrate toward drinking water resources (see Sections 6.2.2.2 and 6.3.2.4).

Additionally, some hydraulic fracturing operations involve the injection of fluids into formations where there is relatively limited vertical separation from drinking water resources. The EPA identified an estimated 4,600 wells that were located in areas with less than 2,000 ft (610 m) of vertical separation between the fractures and the base of protected ground water resources.

There are places in the subsurface where oil and gas reservoirs and drinking water resources co-exist in the same formation. Evidence we examined suggests that some hydraulic fracturing for oil and gas occurs within formations where the ground water has a salinity of less than 10,000 mg/L TDS. By definition, this results in the introduction of fracturing fluids into formations that meet the Safe Drinking Water Act (SDWA) salinity-based definition of a source of drinking water and the broader definition of a drinking water resource developed for this assessment. According to the data we examined, these formations are generally in the western United States.

The practice of injecting fracturing fluids into a formation that also contains a drinking water resource directly affects the quality of that water, since it is likely some of that fluid remains in the formation following hydraulic fracturing. Hydraulic fracturing in a drinking water resource may be of concern in the short-term (where people are currently using these zones as a drinking water supply) or the long-term (if drought or other conditions necessitate the future use of these zones for drinking water).

There are other cases in which production wells associated with hydraulic fracturing are alleged to have caused drinking water contamination. Data limitations in most of those cases (including the unavailability of information in litigation settlements resulting in sealed documents) make it impossible to definitively assess whether or not hydraulic fracturing was a cause of the contamination in these cases.

6.4.2. Factors Affecting Frequency and Severity of Impacts

Proper cementing across oil-, gas-, or water-bearing zones prevents the movement of brines, gas, or hydraulic fracturing fluids along the well into drinking water resources. The likelihood of contamination is reduced when the well is fully cemented across these zones; however, this is not the case in all hydraulically fractured wells, either because the cement does not extend completely through the base of the drinking water resource or the cement that is present is not of adequate quality. Fully cemented surface casing that extends through the base of drinking water resources is a key protective component of the well. Most, but not all, wells used in hydraulic fracturing operations have fully cemented surface casing.

Deviated and horizontal wells, which are increasingly being used in hydraulic fracturing operations, may exhibit more casing and cement problems compared to vertical wells. Sustained casing pressure—a buildup of pressure within the well annulus that can indicate the presence of small leaks—occurs more frequently in deviated and horizontal wells compared to vertical wells. Cement integrity problems can also arise as a result of challenges in placing cement in these wells, because they are more challenging than vertical wells to center properly.

Older wells may exhibit more integrity problems compared to newer wells, which may be an issue if older wells are hydraulically fractured or re-fractured. Degradation of the casing and cement as they age or the cumulative effects of stresses exerted on the well over time may result in changes in well integrity. Integrity problems can also be associated with the inadequate design of wells that were constructed pursuant to older, less stringent requirements. Well components that are subject to corrosive environments, high pressures, or other stressors tend to have more problems than wells without these additional stressors.

The extent of subsurface fluid migration within subsurface rock formations and the potential for the development of pathways that can adversely affect drinking water depend on site-specific characteristics. These include the physical separation between the production zone and drinking water resources, the geological and geomechanical characteristics of the formations, hydraulic fracturing operational parameters, and the physical characteristics of any connecting feature (e.g., abandoned wells, faults, and natural fractures).

As noted above, vertical separation between the production zone and drinking water resources protects drinking water. Additionally, the proximity of wells undergoing hydraulic fracturing to other wells increases the potential for the formation of pathways for fluids to move via these wells to drinking water resources. For example, if there is a deficiency in the construction of a nearby well (or degradation of the well components), that well could serve as a pathway for movement of fracturing fluids, methane, or brines that might affect a drinking water resource. If the fractures were to intersect an uncemented portion of a nearby wellbore, the fluids could migrate along that wellbore into any uncemented formations.

Fractures created during hydraulic fracturing can extend out of the target production zone. Out-of-zone fracturing could be a concern for fluid migration if the hydraulic fracturing operation is not designed to address site-specific conditions, for example if the production zone is thin and fractures propagate to unintended vertical heights, or if the production zone is not horizontally continuous and fractures extend to unintended horizontal lengths. The presence of natural faults or fractures can affect the extent of hydraulic fractures. When faults are present, relatively larger microseismic responses are seen during hydraulic fracturing, and larger fracture growth can occur than in the absence of natural faults or fractures. However, modeling studies indicate that fluid migration from deep production zones to shallow drinking water resources along natural faults and fractures or offset wells is unlikely. These studies indicate that, in both cases, gas available for migration is limited to the amount that existed in the fractures and pore space of connecting features following hydraulic fracturing prior to production. Following the completion of a hydraulic fracturing treatment, depressurization of the production formation surrounding the fractures due to hydrocarbon production would make upward fluid migration into drinking water resources unlikely to occur.

Based on the information presented in this chapter, the increased deployment of hydraulic fracturing associated with oil and gas production activities, including techniques such as horizontal drilling and multi-well pads, may increase the likelihood that these pathways could develop. This, in turn, could lead to increased opportunities for impacts on drinking water resources.

6.4.3. Uncertainties

Generally, less is known about the occurrence of (or potential for) impacts of injection-related pathways in the subsurface than for other components of the hydraulic fracturing water cycle, which can be observed and measured at the surface. Furthermore, while there is a significant amount of information available on production wells in general, there is little information that is specific to hydraulic fracturing operations and much of this data is not readily accessible, i.e., in a centralized, national database.

6.4.3.1. Limited Availability of Information Specific to Hydraulic Fracturing Operations

There is extensive information on the design goals for hydraulically fractured oil and gas wells (i.e., to address the stresses imposed by high-pressure, high-volume injection), including from industry-developed best practices documents. Additionally, based on the long history of oil and gas production activities, we know how production wells are constructed and have performed over time. Over the years, many studies have documented how these wells are constructed, how they perform, and the rates at which they experience problems that can lead to the formation of pathways for fluid movement. However, because we do not know which of these wells were hydraulically fractured, we cannot definitively determine whether the rates at which integrity problems arise (or other data pertaining to oil and gas wells in general) directly correspond to wells used in hydraulic fracturing operations.

Because wells that have been hydraulically fractured must withstand many of the same downhole stresses as other production wells, we consider studies of the pathways for impacts to drinking water resources in production wells to be relevant to identifying the potential pathways relevant to hydraulic fracturing operations. However, without specific data on the as-built construction of wells used in hydraulic fracturing operations, we cannot definitively state whether these wells are consistently constructed to meet the stresses they may encounter.

There is also, in general, very limited information available on the monitoring and performance of wells used in hydraulic fracturing operations. Published information is sparse regarding mechanical integrity tests (MITs) performed during and after hydraulic fracturing, including MIT results, the frequency at which mechanical integrity issues arise in wells used for hydraulic fracturing, and the degree and speed with which identified issues are addressed. There is also little information available regarding MIT results for the original hydraulic fracturing in wells built for that purpose, for wells that are later re-fractured, or for existing, older wells not initially constructed for hydraulic fracturing but repurposed for that use.

There are also a limited number of published monitoring studies or sampling data that provide evidence to assess whether formation brines, injected fluids, or gas move in unintended ways through the subsurface during and after hydraulic fracturing. Subsurface monitoring data (i.e., data that characterize the presence, migration, or transformation of fluids in the subsurface related to hydraulic fracturing operations) are scarce relative to the tens of thousands of oil and gas wells that are estimated to be hydraulically fractured across the country each year (see Chapter 2).

Information on fluid movement within the subsurface and the extent of fractures that develop during hydraulic fracturing operations is also limited. For example, limited information is available in the published literature on how flow regimes or other subsurface processes change at sites where hydraulic fracturing is conducted. Instead, much of the available research, and therefore the literature, addresses how hydraulic fracturing and other production technologies perform to optimize hydrocarbon production.

These limitations on hydraulic fracturing-specific information make it difficult to provide definitive estimates of the rate at which wells used in hydraulic fracturing operations experience the types of integrity problems that can contribute to fluid movement.

6.4.3.2. Limited Systematic, Accessible Data on Well Performance or Subsurface Movement

While the oil and gas industry generates a large amount of information on well performance as part of operations, most of this is proprietary or otherwise not readily available to states or the public in a compiled or summary manner. Therefore, no national or readily accessible way exists to evaluate the design and performance of individual wells or wells in a region, particularly in the context of local geology or the presence of other wells and/or hydraulic fracturing operations. Many states have large amounts of operator-submitted data, but information about construction practices or the performance of individual wells is typically not in a searchable or aggregated form that would enable assessments of well performance under varying settings, conditions, or timeframes. Although it is collected in some cases, there is also no systematic collection, reporting, or publishing of empirical baseline (pre-drilling and/or pre-fracturing) and post-fracturing monitoring data that could indicate the presence or absence of hydraulic fracturing-related fluids in shallow zones and whether or not migration of those fluids has occurred. Ideally, data from ground water monitoring are needed to complement theories and modeling on potential pathways and fluid migration.

While some of the types of impacts described above may occur quickly (i.e., on the scale of days or weeks, as with integrity problems or well communication events), other impacts (e.g., in slow-moving, deep ground waters) may only occur or be able to be detected on much longer timescales. Given the surge in the number of modern high-pressure hydraulic fracturing operations dating from the early 2000s, evidence of any fracturing-related fluid migration affecting a drinking water resource (as well as the information necessary to connect specific well operation practices to a drinking water impact) could take years to discover.

The limited amount of information hinders our ability to evaluate whether—or how frequently—drinking water impacts are occurring (or the potential for these impacts to occur) or to tie possible impacts to specific well construction, operation, or maintenance practices. This also significantly limits our ability to evaluate the aggregate potential for hydraulic fracturing operations to affect drinking water resources or to identify the potential cause of drinking water contamination or suspected contamination in areas where hydraulic fracturing occurs.

6.4.4. Conclusions

Fluids can migrate from the wellbore and surrounding subsurface formations due to inadequate casing or cement, and via natural and man-made faults, fractures, and offset wells or mines (see Text Box 6-5). To prevent fluid migration through the wellbore or through subsurface pathways, wells must have adequate casing and cement, and induced fractures must not intersect existing fractures or permeable zones that lead to drinking water resources. Evidence shows that the quality of drinking water resources may have been affected by hydraulic fracturing fluids escaping the wellbore and surrounding formation in certain areas, although conclusive evidence is currently limited.

Text Box 6-5. Research Questions Revisited.

How effective are current well construction practices at containing fluids—both liquids and gases—before, during, and after fracturing?

- Wells that were designed with uncemented intervals of casing across porous or permeable zones, wells in which cementing does not resist formation or operational stresses, and wells in which cementing does not meet design specifications have the potential to promote unintended subsurface fluid movement. Even in optimally designed wells, metal casings and cement can degrade over time, either as a result of aging or of exposure to stresses exerted over years of operations. See Section 6.2.2.2.
- We have limited information on the degree to which wells are designed and constructed with the multiple layers of casing that can withstand hydraulic fracturing pressures and contact with injected and produced fluids. We also are lacking information about whether wells have suitable cements that can prevent fluid movement outside the wellbore and between the production zone and drinking water resources. We also do not have information on the degree to which mechanical integrity is verified before or after hydraulic fracturing operations. See Section 6.2.2.1.

Can subsurface migration of fluids—both liquids and gases—to drinking water resources occur and what local geologic or artificial features might allow this?

- The presence of artificial penetrations, especially poorly constructed offset wells or undetected abandoned wells, mines, or other subsurface structures, provides pathways that, in the presence of a driving force, could allow for fluid movement to shallow geologic zones such as drinking water resources. See Section 6.3.2.3.

- Intersections of induced fractures with transmissive faults or naturally occurring fractures or porous/permeable rock zones can allow fluids to move out of the targeted fracture areas. However, modeling studies indicate that fluid migration from production zones to drinking water resources along natural faults and fractures is unlikely. See Section 6.3.2.4.
- Some hydraulic fracturing operations involve the injection of fluids into formations where there is relatively limited vertical separation from drinking water resources. Other hydraulic fracturing is performed within formations that meet the SDWA or state salinity-based definition of a source of drinking water, in addition to the broader definition of a drinking water resource developed for this assessment. See Section 6.3.2.

6.5. References for Chapter 6

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