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Review of Well Operator Files for Hydraulically Fractured Oil and Gas Production Wells:

Well Design and Construction

United States Environmental Protection Agency
Office of Research and Development

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U.S. Environmental Protection Agency
Office of Research and Development
Washington, DC

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Preface

The U.S. Environmental Protection Agency (EPA) is conducting a study of the potential impacts of hydraulic fracturing for oil and gas on drinking water resources. This study was initiated in Fiscal Year 2010 when Congress urged the EPA to examine the relationship between hydraulic fracturing and drinking water resources in the United States. In response, the EPA developed a research plan (*Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*) that was reviewed by the agency's Science Advisory Board (SAB) and issued in 2011. A progress report on the study (*Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report*), detailing the EPA's research approaches and next steps, was released in late 2012 and was followed by a consultation with individual experts convened under the auspices of the SAB.

The EPA's study includes the development of several research projects, extensive review of the literature and technical input from state, industry, and non-governmental organizations as well as the public and other stakeholders. A series of technical roundtables and in-depth technical workshops were held to help address specific research questions and to inform the work of the study. The study is designed to address research questions posed for each stage of the hydraulic fracturing water cycle:

- Water Acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- Chemical Mixing: What are the possible impacts of surface spills of hydraulic fracturing fluids on or near well pads on drinking water resources?
- Well Injection: What are the possible impacts of the injection and fracturing process on drinking water resources?
- Flowback and Produced Water: What are the possible impacts of surface spills of flowback and produced water on or near well pads on drinking water resources?
- Wastewater Treatment and Waste Disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

This report, *Review of Operator Files for Hydraulically Fractured Oil and Gas Production Wells: Well Design and Construction*, is the product of one of the research projects conducted as part of the EPA's study. It has undergone independent, external peer review in accordance with agency policy and all of the peer review comments received were considered in the report's development.

The EPA's study will contribute to the understanding of the potential impacts of hydraulic fracturing activities for oil and gas on drinking water resources and the factors that may influence those impacts. The study will help facilitate and inform dialogue among interested stakeholders, including Congress, other Federal agencies, states, tribal government, the international community, industry, non-governmental organizations, academia, and the general public.

Authors and Contributors

Glen Boyd, PhD, The Cadmus Group, Inc., under contract EP-C-08-015

Susan Burden, PhD, US EPA

Guy W. Cole, MS, MPP, Student Services Contractor for US EPA, under contract EP-12-H-000389

Charles J. Hillenbrand, PhD, US EPA

Andrea T. Joffe, BS, Randstad Technologies, under contract EP-C-10-023

David Marker, PhD, Westat, under contract EP-C-10-023

Gregory Oberley, MS, US EPA

Susan L. Sharkey, MA, US EPA

Chuck Tinsley, BS, US EPA

José E. Torres, MS, US EPA

Nathan M. Wiser, MA, US EPA

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The EPA would also like to acknowledge the participants of the *US EPA-States Technical Meeting on the Well File Review* for their insights on well design and construction. The meeting was held in Dallas, Texas, on July 15, 2014, and included representatives from the following state agencies:

Arkansas Department of Environmental Quality

Arkansas Natural Resource Commission

Colorado Department of Public Health and Environment

Colorado Oil and Gas Conservation Commission

Louisiana Department of Natural Resources

Louisiana Office of Conservation

New Mexico Energy, Minerals, and Natural Resources Department

North Dakota Industrial Commission

Oklahoma Corporation Commission

Oklahoma Department of Environmental Quality

Oklahoma Water Resources Board

Pennsylvania Department of Environmental Protection

Railroad Commission of Texas

Texas Commission on Environmental Quality

Wyoming Department of Environmental Quality

Executive Summary

Hydraulically fractured oil and gas production wells are designed, constructed, and completed to access and extract hydrocarbons from targeted geologic formations. Well components, such as the casing and cement used to construct production wells, can block pathways for unintended subsurface gas and liquid movement to ground water resources. To help understand the role of well design and construction practices in preventing pathways for subsurface fluid movement, the EPA conducted a survey of oil and gas production wells hydraulically fractured by nine oil and gas service companies in the United States during 2009 and 2010. The objective of the study was to describe, for these wells: (1) well design and construction characteristics of hydraulically fractured oil and gas production wells, (2) the relationship of well design and construction characteristics to drinking water resources,[1] and (3) the number and relative location of well construction barriers (i.e., casing and cement) that can block pathways for potential subsurface fluid movement.

A statistically representative sample of 323 study wells was selected from a list of well identifiers corresponding to onshore oil and gas production wells that were reported by the nine service companies. Drilling, construction, completion, and operation information for the selected wells was collected from nine well operators and summarized. 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 percent confidence intervals. The results are statistically representative of an estimated 23,200 (95 percent confidence interval: 21,400-25,000) onshore oil and gas production wells hydraulically fractured in 2009 and 2010 by the nine service companies.

Well Design and Construction Characteristics of Hydraulically Fractured Oil and Gas Production Wells. Oil and gas production wells hydraulically fractured by the nine service companies in 2009 and 2010 were predominately vertical wells drilled between 2000 and 2010, but also included other well orientations (i.e., horizontal and deviated) and wells drilled prior to 2000. True vertical depths of the wells ranged from less than 2,000 feet below ground surface to more than 11,000 feet below ground surface. Hydraulically fractured rock formations included sandstone, shale, carbonate, coal, and chert.

Despite variations in well design and construction practices, data collected for this study indicate that some well design and construction characteristics are common. All wells represented in this study had surface casing, 39 (18-65) percent[2] had intermediate casing, and 94 (67-99) percent[3] had production casing. The most common casing configuration, used in 55 (33-75) percent[4] of wells,

[1] The EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* defined "drinking water resources" as any body of water, ground or surface, that currently serves or in the future could serve as a source of drinking water for public or private water supplies.

[2] 9,100 (2,900-15,400) wells

[3] 21,900 (19,200-24,600) wells

[4] 12,800 (7,600-18,000) wells

was reported to be a surface and a production casing. Eighty-seven (68-96) percent[5] of wells had casing in the production zone that was cemented and perforated for hydraulic fracturing.

The presence or absence of cement around casing was evaluated for surface, intermediate, and production casings. Casings were found to be either fully cemented, partially cemented, or uncemented. Fully cemented casings were defined, in this study, 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). Conversely, 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. 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. Ninety-three (87-96) percent[6] of surface casings were fully cemented, and 80 (57-92) percent[7] of intermediate casings were fully cemented. Fifty-two (33-70) percent[8] of production casings were partially cemented, while 36 (18-60) percent[9] were fully cemented. When partially cemented, generally more than 50 percent of the measured length of the production casing (between the bottom of the casing and the next larger and overlying casing) was cemented.

Relationship to Drinking Water Resources. Drinking water resources (i.e., surface water bodies, public water supply intakes, and ground water wells) were commonly found within a 0.5 mile radius of study wellhead locations. Eighty-two (63-92) percent[10] of the wells represented in this study were located within 0.5 miles of a surface water resource (i.e., lake, pond, or river); this report does not identify whether surface water resources currently serve as drinking water resources. Fewer production wells were located within 0.5 miles of either a private ground water well [13 (7-23) percent[11]] or a public water supply well [2 (1-10) percent[12]]. An estimated 74 (51-88) percent[13] of wells had more than one water feature within the 0.5 mile radius.

Since there is variation among states with respect to the definition of protected ground water, this study relied solely on depths to protected ground water resources that were provided by well operators. In the majority of cases, operator-reported depths to protected ground water resources were based on state or federal authorization documents (e.g., permits to drill or permit applications). Operator-reported depths to protected ground water resources ranged from just

[5] 20,200 (17,500-23,000) wells

[6] 21,500 (19,500-23,600) wells

[7] 7,300 (600-13,900) wells

[8] 10,900 (6,900-14,900) wells

[9] 8,300 (3,800-12,800) wells

[10] 18,900 (15,200-22,600) wells

[11] 3,000 (900-5,100) wells

[12] 600 (10-1,500) wells

[13] 17,100 (12,400-21,900) wells

below ground surface to 8,000 feet deep. Ninety-two (81-97) percent[14] of wells passed through operator-reported protected ground water resources no greater than 2,000 feet deep.

Cement was placed in the annular space between the outside of the casing and the protected ground water resources reported by well operators in most wells. Surface casing, which was found to be fully cemented in 93 (87-96) percent[15] of wells, extended below the base of the operator-reported protected ground water in 55 (35-73) percent[16] of wells. In an additional 28 (10-55) percent[17] of 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 3 (0.5-13) percent[18] of wells.

Casing and Cement as Barriers to Potential Subsurface Fluid Movement. Subsurface fluid movement depends on a number of factors, including the existence of a pathway, the presence of a fluid, and a driving force (e.g., pressure differential). This report focuses only on the potential for wellbore pathways to exist and does not address other possible pathways or the role of other factors. The presence of pathways alone does not indicate that subsurface gas and liquid movement will occur or is occurring, because fluid movement also depends on the other factors identified above. Two potential pathways related to well construction were considered: from the inside of the well to the outside and along the outside of the well. Subsurface fluid movement to ground water resources may occur though either potential pathway or a combination of both potential pathways. The presence or absence of casing and cement along the well was evaluated to determine the number of well construction barriers to subsurface fluid movement via these potential pathways.

The first potential pathway—from the inside of the well to the outside—can occur at any point along the length of the well and depends, in part, on the presence or absence of casing and cement. At depths corresponding to the targeted geologic formation, this pathway is created when casing and cement are perforated for hydraulic fracturing or when a well is completed with an open hole. At other depths, multiple casing and cement barriers can prevent this pathway from forming, because all barriers would need to fail in order for a pathway from the inside of the well to the outside to occur. Wells represented in this study had a range in the number of casing and cement barriers, from zero in open hole completions to six when surface, intermediate, and production casing were each cemented to the surface. The most common number of barriers, at any point along a well, was either two (one casing string and one cement sheath) or three (two casing strings and one cement sheath). Nearly all wells represented in this study had perforations used for hydraulic fracturing that were placed deeper than the base of the operator-reported protected ground water resources; 0.4 (0.1-3) percent[19] of wells had perforations placed shallower than the base of the protected ground water resource reported by the operator.

[14] 21,400 (18,900-24,000) wells

[15] 21,500 (19,500-23,600) wells

[16] 12,600 (8,000-17,300) wells

[17] 6,400 (500-12,300) wells

[18] 600 (10-1,800) wells

[19] 90 (10-300) wells

The second potential pathway considered—along the outside of the well—can also occur at any point along the well's length and depends upon the presence or absence of cement and the quality of the cement present. More than half of the wells represented in this study had two or more cemented casings between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resources. This indicates that there were often two or more barriers to subsurface fluid movement along the outside of a well, from the targeted geologic formation to protected ground water resources reported by well operators. Multiple cemented casings between the shallowest point of hydraulic fracturing and operator-reported protected ground water resources did not preclude the presence of uncemented intervals along the outside of the well, which can be pathways for fluid movement along the outside of the well. Sixty-six (44-83) percent[20] of wells had one or more uncemented intervals along the outside of the well, from the bottom of the well to the ground surface, while 29 (13-53) percent[21] were fully cemented over the same interval.

Study Limitations. The survey design and data collection process may have implications for the interpretation of the results presented in this report. The results are statistically representative of oil and gas production wells hydraulically fractured by nine oil and gas service companies in the continental United States during 2009 and 2010. The extent to which these results may be statistically representative of all production wells hydraulically fractured in the United States during the same time period could not be determined. Nevertheless, comparisons between wells in this study and other data on oil and gas production in the United States during 2009 and 2010 suggest that observations made in this report are likely indicative of oil and gas production wells hydraulically fractured during this time period.

Estimates of the frequency of occurrence of well design and construction characteristics are presented at the national scale. Estimates may be different for different regions of the country, because of differences in local geologic characteristics, state regulations, and company preferences. It is also possible that the estimates presented in this report may not apply to wells constructed and hydraulically fractured after 2010, if well design and construction practices have changed (e.g., a greater proportion of horizontal well completions). Additionally, the results presented in this report are generated from data provided by oil and gas well operators. The EPA did not attempt to independently and systematically verify data supplied by operators. Consequently, the study results, which include comparisons of operator-reported protected ground water resources to well construction characteristics, are of the same quality as the supplied data.

Key Findings. This report presents the results of a survey of onshore oil and gas production wells hydraulically fractured in the continental United States during 2009 and 2010, using data provided by well operators. Two potential pathways for subsurface fluid movement were examined—from the inside of the well to the outside and along the outside of the well. The following key findings contribute to an understanding of the role of well design and construction practices with respect to these pathways:

[20] 15,300 (10,500-20,100) wells

[21] 6,800 (1,600-11,900) wells

> *The wells generally had multiple layers of casing and cement that can act as barriers to subsurface fluid movement by interrupting pathways for potential subsurface fluid movement.* Multiple casing and cement barriers can prevent pathways from forming, because all barriers would need to fail in order for a pathway for potential subsurface fluid movement to occur. The most common number of barriers to potential subsurface fluid movement from inside of the well to the outside, at any point along the well, was either two (one casing string and one cement sheath) or three (two casing strings and one cement sheath). Additionally, there were often two or more barriers (i.e., cemented casings) to potential subsurface fluid movement along the outside of a well, from the targeted geologic formation to operator-reported protected ground water resources.

> *While multiple barriers were often present in hydraulically fractured oil and gas production wells, pathways for potential subsurface fluid movement were identified in some wells.* Uncemented intervals have been shown to be pathways for subsurface fluid movement along the outside of the well. An estimated 66 (44-83) percent[22] of wells had one or more uncemented intervals, and 3 (0.5-13) percent[23] of wells had uncemented intervals within the operator-reported protected ground water resources. Casing perforations placed at depths shallower than the base of operator-reported protected ground water resources can create a pathway for fluids to flow from the inside of the well to a ground water resource, if a ground water resource is present at that depth. An estimated 0.4 (0.1-3) percent[24] of wells had perforations used for hydraulic fracturing that were placed shallower than the base of the operator-reported protected ground water resource.

These results, as well as other information on well characteristics, the relationship between drinking water resources and hydraulically fractured wells, and casing and cement barriers that can prevent subsurface fluid movement, highlight important factors that should be considered when assessing the potential impacts of hydraulically fractured oil and gas production wells on drinking water resources.

[22] 15,300 (10,500-20,100) wells

[23] 600 (10-1,800) wells

[24] 90 (10-300) wells

1. Introduction

The importance of oil and gas production well design and construction in isolating and protecting ground water resources is well-known [Ground Water Protection Council (GWPC), 2014; GWPC and ALL Consulting, 2009; King and King, 2013]. Several studies, however, suggest that the construction of oil and gas production wells may introduce pathways along which fluids may move, potentially leading to impacts to drinking water resources (Harrison, 1983, 1985; Jackson et al., 2013a; Jackson et al., 2013b; Ohio Department of Natural Resources, 2008; Osborn et al., 2011; Van Stempvoort et al., 2005; Watson and Bachu, 2009). For example, the Ohio Department of Natural Resources (2008) determined that inadequately cemented casing contributed to natural gas migration to a ground water resource by creating a pathway that connected a high pressure gas zone to the ground water resource. As demonstrated by this case, subsurface fluid movement depends on many factors, including the existence of a pathway, the presence of a fluid, and a driving force (e.g., pressure differential).

The U.S. Environmental Protection Agency's (EPA) *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* identified the potential importance of well construction practices in preventing pathways for subsurface fluid movement before, during, and after hydraulic fracturing [US Environmental Protection Agency (US EPA), 2011]. To help understand the role of well design and construction practices in preventing pathways for potential subsurface fluid movement, the EPA conducted a statistical survey of oil and gas production wells hydraulically fractured by nine service companies in the United States during 2009 and 2010. The objective of the study was to describe, for these wells: (1) well design and construction characteristics of hydraulically fractured oil and gas production wells, (2) the relationship of well design and construction characteristics to drinking water resources,[25] and (3) the number and relative location of well construction barriers (i.e., casing and cement) that can block pathways for potential subsurface fluid movement. This report focuses on the potential for wellbore pathways to exist and does not address other possible pathways or the role of other factors (i.e., the presence of a fluid or a driving force) in subsurface fluid movement. Results from this study provide a summary of well design and construction characteristics associated with oil and gas production wells hydraulically fractured in the United States during 2009 and 2010, using data provided by well operators.

2. Well Construction Overview and Definitions

Most oil and gas production well locations have ground water and/or hydrocarbons in the pore spaces of rock formations in the subsurface. Ground water is often variable in quality, generally containing greater amounts of dissolved solids with greater depth, although localized geologic structure and hydrogeologic history can also influence its quality (Chebotarev, 1955; Freeze and Cherry, 1979). In this report, a ground water resource is considered to be any geologic formation containing ground water. Certain ground water resources may be considered for protection as drinking water resources, depending on ground water quality and local regulatory requirements.

[25] The EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (2011) defined "drinking water resources" as any body of water, ground or surface, that currently serves or in the future could serve as a source of drinking water for public or private water supplies (US EPA, 2011).

The type and amount of hydrocarbons also vary in the subsurface, with certain geologic formations containing more hydrocarbons than others. Depending on the price of hydrocarbon resources, it may be considered economically viable to extract hydrocarbons at one or more depths. These resources become the targeted geologic formations for oil and gas companies. An oil and gas production well that penetrates through a ground water resource can act as a pathway for potential subsurface fluid movement by connecting the resource to other formations that may contain hydrocarbons, saline water, or both. Well components, such as the casing and cement used to construct production wells, can block pathways for unintended subsurface gas and liquid movement to ground water resources. When these pathways are blocked, the well is said to have "zonal isolation." (Baker, 1979; Bellabarba et al., 2008; Smith, 1976)

Oil and gas production wells are designed, constructed, and completed to access and extract hydrocarbons from targeted geologic formations. Well construction includes drilling, casing installation, and cementing the casing to the wellbore wall. Activities associated with these steps are generally determined based on the subsurface environment, including the subsurface pressures encountered between the surface and the bottom of the well (Ross and King, 2007; Spellman, 2013). Industry best management practices and state regulations that address regional and local characteristics can also influence well design and construction (GWPC, 2014; Spellman, 2013). Well completion activities prepare a well for production and include casing perforation, stimulation (including, but not limited to, hydraulic fracturing), and installation of production tubing if desired. Production well completion is generally influenced by target zone characteristics, such as porosity, permeability, and lithology (Martin and Valkó, 2007; Ross and King, 2007). Existing oil and gas production wells can be recompleted in hydrocarbon-bearing zones that were not the original targeted geologic resource (International Association of Drilling Contractors, 2015). Original well design and construction characteristics may change when a well is recompleted. For example, well files reviewed for this study showed changes in the location of casing perforations, the addition of cement, and the removal of uncemented casing.

In general, oil and gas production wells are constructed by repeating several basic steps. In the first step, a hole is drilled to a pre-determined depth or until a geologic target is reached. In the second step, a steel pipe is lowered into the hole. When the steel pipe extends from the bottom of the hole to the ground surface, it is referred to as a "casing." When the steel pipe extends from one subsurface depth to another subsurface depth within the well, it is often referred to as a "liner." In the last step, cement is placed between the outside of the casing and the inside of the drilled hole (i.e., the wellbore) to seal off this annular space (Baker, 1979; Smith, 1976). The cement also provides support behind the casing and to protect it from corrosive fluids in the subsurface (Baker, 1979; Smith, 1976). The process repeats, with the next hole drilled using a smaller diameter drill bit that fits inside the existing casing.

Casings installed at different points in time and at different depths have different names. For this report, casings are defined as follows:

> **Conductor casing** is generally less than 100 feet deep and is often uncemented. Its purpose is to prevent the in-fill of unconsolidated dirt and rock in the uppermost few feet of the drilled hole (Baker, 1979; Devereux, 1998).

Surface casing is the shallowest cemented casing, with the widest diameter. Cemented surface casing generally serves as an anchor for blowout protection equipment and to seal off certain ground water resources (Baker, 1979).

Intermediate casing, when cemented, generally seals off intermediate depths and geologic formations that may have considerably different reservoir pressures than deeper zones to be drilled (Baker, 1979; Devereux, 1998). This can include coal mine zones, gas storage zones, intermediate-depth hydrocarbon production zones, or ground water resources located at depths below the surface casing.

Production casing is the deepest casing set and serves primarily as the conduit for producing fluids. When cemented to the wellbore, this casing can also serve to seal off other subsurface zones, including ground water resources (Baker, 1979; Devereux, 1998). Production casing is secured to the wellbore using either cement or formation packers, which are devices that inflate or mechanically seal the annular space between the casing and the wellbore. For this report, any casing or liner with production perforations was considered to be a "production casing." In some cases, this can include casing identified as "intermediate" by the operator, but later perforated for production purposes.

Figure 1 provides a simplified, generic well diagram illustrating the casings defined above. Note that not all hydrocarbon-bearing zones in the subsurface are necessarily produced or stimulated using hydraulic fracturing and that not all ground water resources may be considered protected. This figure is meant to show relationships between well casings and subsurface resources, but should not be interpreted to imply that all wells exhibit similar conditions in the subsurface.

Oil and gas production wells are constructed using different combinations of the casings and liners described above. Figure 2 illustrates the different variations of casings and liners observed in this study. Given the array of possible casing configurations, Figure 2 may not capture all configurations used in hydraulically fractured oil and gas production wells.

Well completion in the targeted geologic formation can also vary. Figure 3 depicts the three types of well completions observed in this study: cemented casing, formation packer, and open hole completions. Cemented casing completions have both casing and cement in the targeted geologic formation. In these completions, the casing and cement are typically perforated, and hydraulic fracturing is performed within the perforated interval. Formation packer completions also have casing, but use formation packers that swell to seal the annulus between the production casing and the wellbore. In these completions, the bottom portion of the production casing, located between formation packers, is equipped with ports that can be opened using pressure applied through the casing. Hydraulic fracturing fluid is pumped through these ports to fracture the surrounding rock formation. Open hole completions contain no casing and, therefore, no cement. Hydraulic fracturing in an open hole completion occurs within the open hole interval and may be conducted using a temporary casing (i.e., a temporary frac string). A temporary frac string is lowered into the well and secured at its base using a packer or by latching into equipment existing deeper in the well. Hydraulic fracturing takes place through the temporary frac string, which is removed when

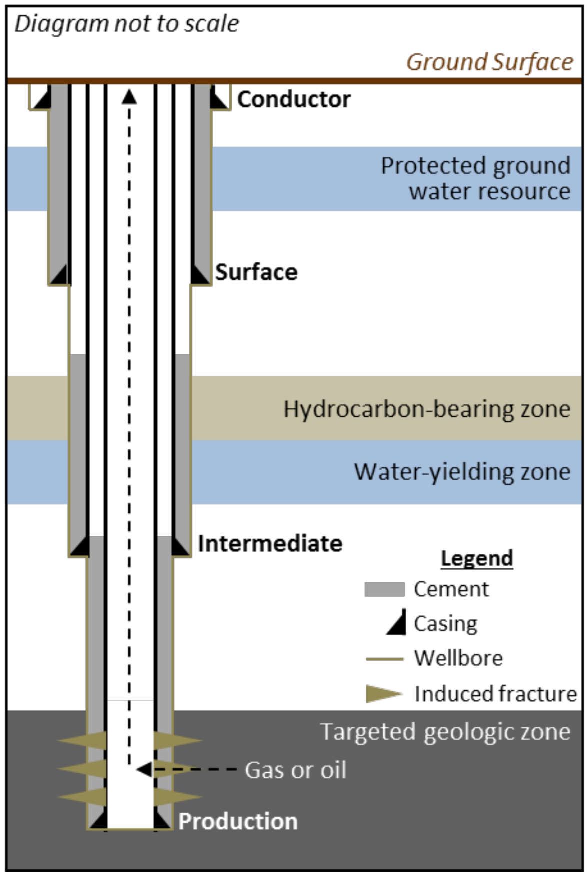

Figure 1. Generic well diagram illustrating conductor, surface, intermediate, and production casing. Relative positions of geologic zones and well construction components vary from well to well and are included only for illustrative purposes. Although shown in this diagram as occurring in singular zones, water is frequently found throughout the entire geologic column in different quantities and qualities, including in the zones containing hydrocarbons. Hydrocarbon-bearing zones may be considered uneconomic and may be left undeveloped. Hydraulic fracturing takes place for the purpose of producing hydrocarbons in targeted geologic zones.

hydraulic fracturing is complete. Temporary frac strings may also be used in wells with casing that may not withstand the pressures applied during hydraulic fracturing.

After hydraulic fracturing, a smaller diameter steel pipe, called "tubing," may be set within the production casing. In open hole settings, the tubing may extend further into the well than the deepest cemented casing. Depending on the installation of the tubing, production fluids may flow up only the inside of the tubing or may flow up both the inside and outside of the tubing to the wellhead.

3. Research Methods

A survey of onshore oil and gas production wells in the continental United States was conducted to better understand well design and construction characteristics associated with hydraulically fractured wells and the relationship between those characteristics and drinking water resources. A statistically representative sample of production wells was selected from a list of oil and gas production wells that were reported by nine service companies to have been hydraulically

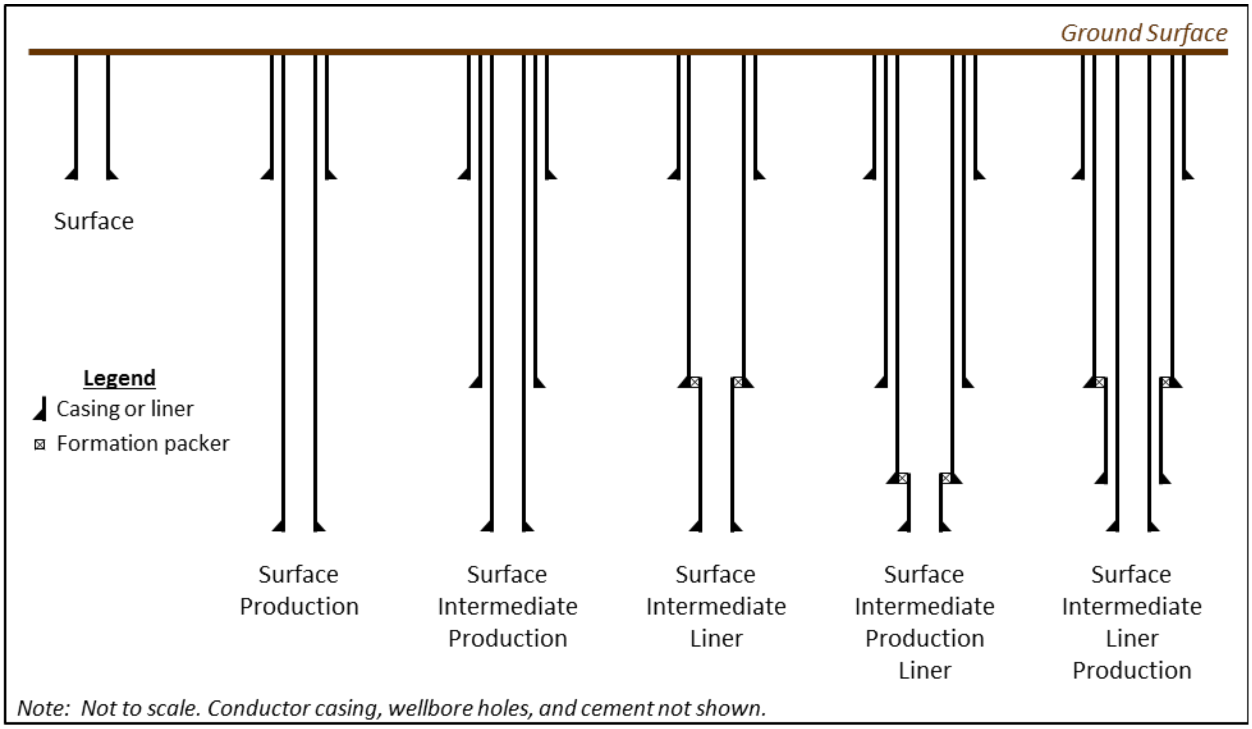

Figure 2. Casing configurations reported in the well operators' files. Casings are steel pipes that extend from ground surface to a predetermined depth and include surface, intermediate, and production casing. Liners are steel pipes that are attached to the base of a casing and extend to a predetermined depth. Casing configurations are depicted for vertical well orientations, but may occur in wells with different orientations (e.g., horizontal).

fractured between approximately September 2009 and September 2010. Drilling, construction, completion, and operation information from the selected wells was collected from well operators and summarized.[26] Results of the survey are presented as estimates of the frequency of occurrence of hydraulically fractured production well design or construction characteristics with 95 percent confidence intervals. This section describes the survey design, the information requested, and the analyses conducted.

3.1. Service Company Well List

Information needed to compile a comprehensive list of hydraulically fractured oil and gas production wells in the United States is not generally available. Therefore, a list of oil and gas production wells that were reported by nine service companies to have been hydraulically fractured between approximately September 2009 and September 2010 was compiled (subsequently referred to as the "service company well list"). The information was provided to the EPA by the nine service companies in response to an information request sent in September 2010 (US EPA, 2010). As part of the information request, each company was asked to identify all sites where they had provided hydraulic fracturing services in the year prior to September 2010.

[26] While a portion of the data needed for this project are reported to state oil and gas agencies, the complete dataset is available only in the records kept by oil and gas well operators.

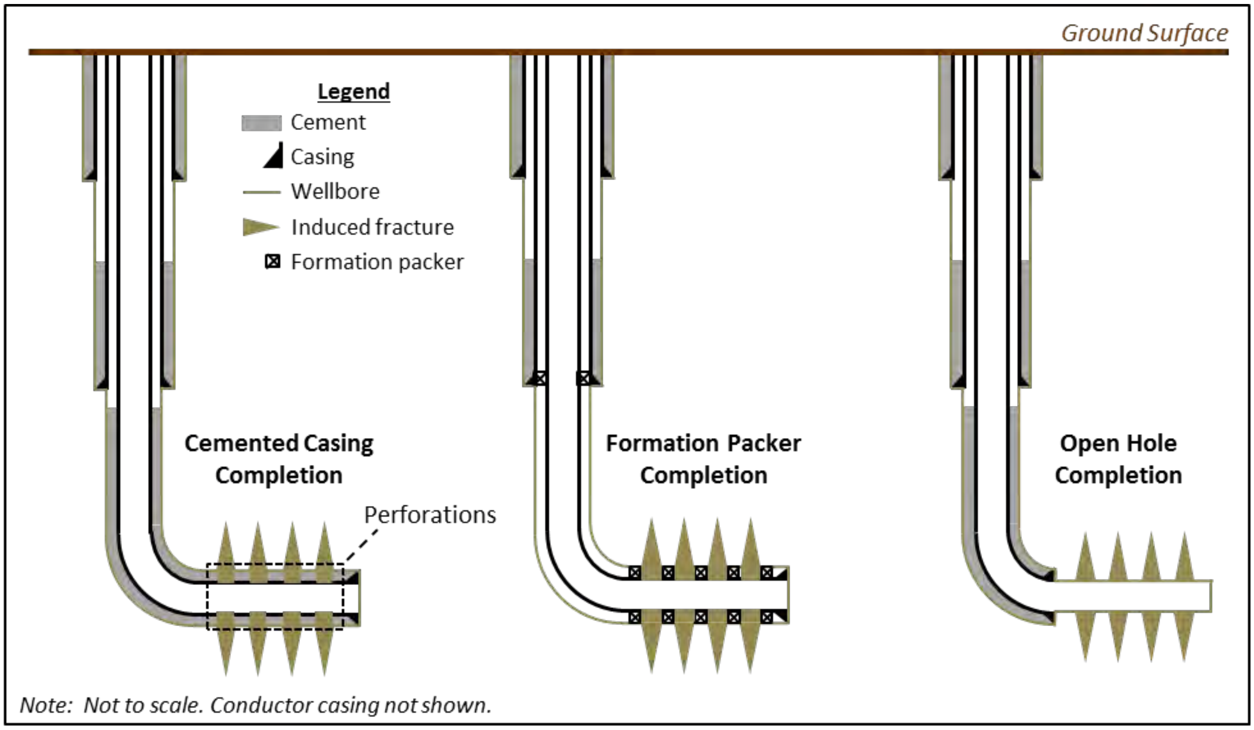

Figure 3. Well completion types reported in the well operators' files. Well completions are depicted for horizontal well orientations, but may occur in wells with different orientations (e.g., vertical).

The nine service companies were selected from a list of 14 hydraulic fracturing service companies identified by the U.S. House of Representatives' Committee on Energy and Commerce (Waxman et al., 2011).[27] The companies selected by the committee included, at that time, the three major hydraulic fracturing service companies, five smaller companies that comprised a growing share of the market, and six additional companies that were selected to assess a broader range of industry practices (Waxman and Markey, 2010; Waxman et al., 2011). Of the 14 hydraulic fracturing service companies identified by the committee, the EPA selected the three major service companies, which included BJ Services Company; Halliburton Energy Services, Inc.; and Schlumberger Technology Corporation. The six remaining service companies were selected to reflect a range of company sizes and geographic diversity (US EPA, 2011; US EPA, 2012). The nine companies selected to receive the EPA's September 2010 information request included: BJ Services Company; Complete Production Services, Inc.; Halliburton Energy Services, Inc.; Key Energy Services; Patterson-UTI Energy; RPC, Inc.; Schlumberger Technology Corporation; Superior Well Services; and Weatherford International.[28]

[27] The EPA was limited to nine service companies (and nine well operators) because of the Paperwork Reduction Act of 1995, which restricts the number of information requests to nine entities per set of queries, unless pre-approved by the Office of Management and Budget.

[28] Four of the nine service companies that reported information to the EPA have been acquired by other companies since 2010. Baker Hughes, Inc., purchased BJ Services Company, Inc., and Patterson-UTI Energy purchased the pressure pumping business from Key Energy Services in 2010. Superior Energy Services acquired Complete Production Services, Inc., in 2012. As of March 2015, Superior Well Services is part of C&J Energy Services.

The nine hydraulic fracturing service companies identified 24,925 well identifiers in response to the EPA's information request.[29] Service companies provided, for each well identifier, the well operator's name, the well's state and county location, and the date(s) of hydraulic fracturing.[30] Well identifiers were reported in 30 of the 33 states (Figure 4) that produced crude oil and/or natural gas in 2009 and 2010 [US Energy Information Administration (US EIA), 2014a, b]. The service company well list did not contain well identifiers in Florida, Missouri, and Oregon, which produced crude oil and/or natural gas in 2009.[31]

Four of the nine service companies, including the three major service companies, individually reported well identifiers in 17 or more states; well identifiers from these four companies made up 82 percent of the well identifiers on the service company well list.[32] The same four companies reported hydraulic fracturing operations in 29 of the 33 oil and gas producing states in the United States in 2009. As such, the service company well list likely resembled the geographic distribution of oil and gas production in the United States at that time.[33] It was not possible to determine whether the service company well list was representative of all hydraulic fracturing operations that occurred between approximately September 2009 and September 2010, because the information needed to compile a comprehensive list of hydraulically fractured oil and gas production wells in the United States does not generally exist.

3.2. Survey Design

A two-stage stratified sampling approach was used to select a diverse set of wells following the principles described in Lohr (2010). As described below, well operators of various sizes were selected in the first stage, while their well identifiers from different geographic areas were selected in the second stage.[34] To the extent that well design, construction, or hydraulic fracturing characteristics vary by company size or geography, this stratification improves the accuracy of the

[29] Well identifiers were either API numbers, well names, job numbers, or other codes assigned by the service company. API numbers are unique 10-digit numbers generally assigned to oil and gas production wells by state oil and gas agencies.

[30] Approximately 75 percent (18,798) of the 24,925 well identifiers in the service company well list had reported dates for hydraulic fracturing between September 1, 2009, and September 30, 2010. There were 626 well identifiers that had reported hydraulic fracturing dates before September 1, 2009, and there were 1,213 well identifiers that had reported hydraulic fracturing dates after September 30, 2010. There were 4,288 well identifiers with no reported hydraulic fracturing date. These wells were assumed to have been hydraulically fractured between September 2009 and September 2010, because the EPA requested that the service companies provide a list of wells for which hydraulic fracturing was conducted within one year prior to the date of the information request letter (September 2010).

[31] Collectively, production from these three states was less than 0.1 percent of all crude oil or natural gas production in the United States in 2009 and 2010 (US EIA, 2014a, b).

[32] The three major service companies contributed 17,065 well identifiers to the service company well list (68 percent of 24,925).

[33] The particular well densities shown in Figure 4 would be expected to change if the six smaller service companies chosen by the EPA were different. However, since the three major service companies provided the majority of the well identifiers, which were spread across the United States, the overall geographic distribution of wells would not be expected to change very much.

[34] The sample of well identifiers from the nine operators was selected using a combination of a two-stage and two-phase sampling approach [Chapters 5 and 12 in Lohr (2010)]. The variance estimator used is appropriate for the combined type of sample (Appendix A).

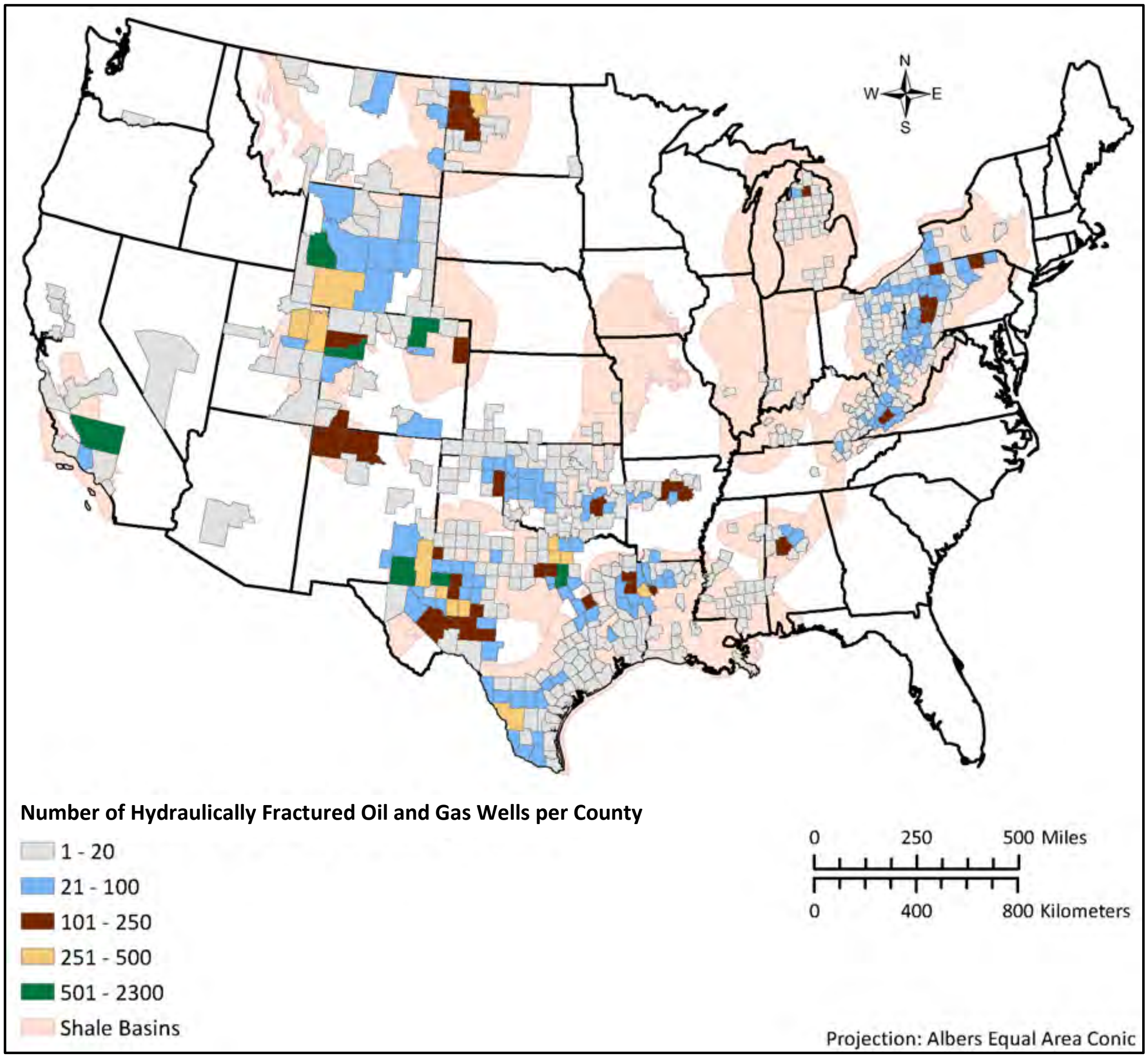

Figure 4. Counties with oil and gas production wells that were reported by nine service companies to have been hydraulically fractured between approximately September 2009 and September 2010. Fewer than 20 well identifiers were reported in Alaska.

estimates presented in this report. If the characteristics are unrelated to company size or geography, the estimates are as accurate as those from an unstratified sample design.

To set up the two-stage stratified sampling, all well identifiers on the service company well list were assigned to one of 24 geographic areas using an April 2011 map of current and prospective shale oil and gas plays within the lower 48 states (subsequently referred to as the "shale play map") (US EIA, 2011). This created an operator-shale play combination for each well identifier based on the well identifier's reported county and state location. Counties containing at least one well identifier from the service company well list were assigned to a geographic area defined as either a single shale play, a cluster of shale plays,[35] or no shale play. If any portion of a county was within one of the shale play boundaries on the map, the entire county was assigned to that shale play or shale play cluster. If no portion of the county was within a shale play, the county was not assigned to any shale play. Because hydraulic fracturing is used to stimulate oil and gas production from many kinds of geologic formations (Gupta and Valkó, 2007), well identifiers located in a county overlying a shale play were not assumed to correspond to wells producing oil or gas from the designated shale play. The shale play map was used solely to identify geographic areas that were later used to select well identifiers for the survey.

Well identifiers in counties assigned to a shale play or a shale play cluster were subsequently grouped into larger geographic regions—either East, South, or West. Well identifiers in counties outside of the mapped shale play boundaries were grouped into a separate region (i.e., the "Other" region). Forty-six well identifiers had unknown counties; these well identifiers were not assigned to any shale play or cluster of shale plays and were assigned to the "Other" region. Geographic regions were used to identify well operators, while the shale play designations influenced the selection of their well identifiers, as described below.

Operator Selection. Nine well operators of various sizes were selected from 1,146 well operators identified in the service company well list. Operator size was defined by the number of well identifiers each company had on the service company well list. Well operators with 10 or more well identifiers were categorized as either "large," "medium," or "small." Large operators were defined as those that accounted for the top 50 percent of the well identifiers on the service company well list, medium operators for the next 25 percent, and small operators for the last 25 percent. As a result, there were 17 large operators, 86 medium operators, and 163 small operators, for a total of 266 well operators that contributed 22,573 different well identifiers to the service company well list (91 percent of 24,925). Each large operator was assigned to the geographic region (i.e., East, South, West, and Other) that contained the largest proportion of its well identifiers to ensure that the final selection of well identifiers would have geographic diversity among large well operators.[36]

There were 880 well operators with fewer than 10 well identifiers on the service company well list. These operators, and their corresponding well identifiers, were excluded from the operator selection process. This ensured that selected operators would each have at least 10 well identifiers eligible for selection in the second stage, which improved the accuracy of the estimates presented in this report. The 880 operators retained a statistical presence in the analysis through the assumption that their wells had characteristics similar to wells from the 163 small operators, as described in Section 3.5.

[35] Shale play clusters were defined as follows: Marcellus, Utica, and Devonian as Marcellus; Floyd-Chattanooga, Floyd-Neal, Chattanooga, and Conasauga as Floyd-Chattanooga; Avalon-Bone Spring and Barnett-Woodford as Avalon-Woodford; Woodford and Woodford-Caney as Woodford-Caney; Monterey and Monterey-Temblor as Monterey; Hermosa and Mancos as Hermosa-Mancos.

[36] Two of the 17 large operators were assigned to the region with their second-largest proportion of wells so that each geographic region had four large operators.

Large, medium, and small operators were selected from the list of 266 well operators. One large well operator was randomly chosen from each of the geographic regions (i.e., one large operator from each of the East, South, West, and Other regions), for a total of four large operators. Two medium operators and three small operators were also chosen at random, with no preference for geographic region. The nine selected operators included: Clayton Williams Energy, Inc.; ConocoPhillips; EQT Corporation; Hogback Exploration, Inc.; Laramie Energy II, LLC; MDS Energy, Ltd.; Noble Energy, Inc.; SandRidge Exploration and Production, LLC; and Williams Production Company, LLC.[37,38]

Well Identifier Selection. The nine operators had a total of 2,455 well identifiers in 15 different shale plays or shale play clusters (including the "non-shale play").[39] Four hundred well identifiers from the nine selected operators were initially chosen for this study. The selection of 400 well identifiers required balancing two goals: maximizing the geographic diversity of wells and maximizing the precision of any forthcoming statistical estimates. The number of well identifiers to be selected from each operator was determined using the optimization algorithm described in Appendix A. Briefly, the algorithm evaluated the statistical precision of different sample sizes selected from 31 unique operator-shale play combinations. Once the sample size for each operator-shale play combination was identified, a random sample of well identifiers was selected from all well identifiers assigned to that shale play or shale play cluster from that operator.

Due to resource and time constraints, 50 of the 400 selected well identifiers were randomly removed,[40] and information was collected from the nine well operators for the remaining 350 well identifiers. Data for 323 well identifiers that corresponded to hydraulically fractured oil and gas production wells were ultimately reviewed. Table 1 summarizes the number of well identifiers excluded from this study and provides explanations for their exclusion. The 323 study wells reflect the geographic distribution of well identifiers reported by the nine hydraulic fracturing service companies (Figure 5).

Because only nine operators were selected, not all shale plays or shale play clusters were able to be sampled. Table 2 provides a comparison between the service company well list and the 323 study wells.[41] When compared with selecting more operators and their wells, the nine operator

[37] ConocoPhillips; EQT Corporation; Noble Energy, Inc.; and Williams Production Company, LLC, were considered "large" operators. Clayton Williams Energy, Inc., and SandRidge Exploration and Production, LLC, were considered "medium" operators. Hogback Exploration, Inc.; Laramie Energy II, LLC; and MDS Energy, Ltd., were considered "small" operators.

[38] As of March 2015, Williams Production Company, LLC, is WPX Energy, Inc.

[39] The 2,455 well identifiers were in 31 unique operator-shale play or operator-shale play cluster combinations (including an operator-non-shale play combination). The final sample of 323 oil and gas production wells included well identifiers from 27 of the 31 combinations.

[40] Well identifiers were first sorted by operator and shale play, and then every eighth well identifier was dropped. This process ensured that well identifiers were removed independent of well operator and geographic location.

[41] The nine operators were reported to have well identifiers in 15 shale plays or shale play clusters, including the non-shale play. The 350 well identifiers initially selected included all 15 shale plays or shale play clusters. The 323 hydraulically fractured oil and gas production wells are located in 13 of the 15 shale plays or shale play clusters. Two shale plays or shale play clusters were not included, because the selected well identifiers corresponded to wells not hydraulically fractured or not operated by one of the nine companies (Table 1).

Table 1. Number of well identifiers included or not included in this study.

Category	Number of Well Identifiers
Included in this study	
Oil and gas production wells	
Hydraulically fractured	323
Not included in this study	
Oil and gas production wells	
Duplicate well	13
Not hydraulically fractured	6
Not drilled	1
Not located in the United States	1
Operated by a different company	1
Hydraulically fractured injection well*	4
Not an oil and gas production well	1
Total number of well identifiers	350

* Class II underground injection control wells

restriction and its subsequent limitation on potential well locations contributed to a lower precision in the results of the well characteristics estimated in this report. Any well characteristics not identified by the study wells are not represented in this report.

3.3. Well Operator Information Request

An information request letter was sent in August 2011 to the nine operators identified above. For each of the 350 well identifiers, the EPA requested 24 distinct items organized into five topic areas: (1) geologic maps and cross sections; (2) drilling and completion information; (3) water quality, volume, and disposition; (4) hydraulic fracturing procedures and reports; and (5) environmental releases. The items requested by the EPA are listed in Appendix B. Operators were asked to certify that, to the best of their knowledge, the information submitted in response to the requested items was true, accurate, and complete.

Approximately 9,670 electronic files and four paper files were received in response to the August 2011 information request. The information in these files was compiled into a single "well file" for each well. In September 2013, follow up letters were sent to each of the operators asking for information not found in the original submissions. Additional information provided by the well operators was added to the corresponding well files. In a few limited cases, the EPA successfully searched state oil and gas websites for information that was requested, but not provided by the operator.[42]

[42] The EPA searched websites for additional information on basic well characteristics, such as latitude/longitude coordinates, production type, or well orientation.

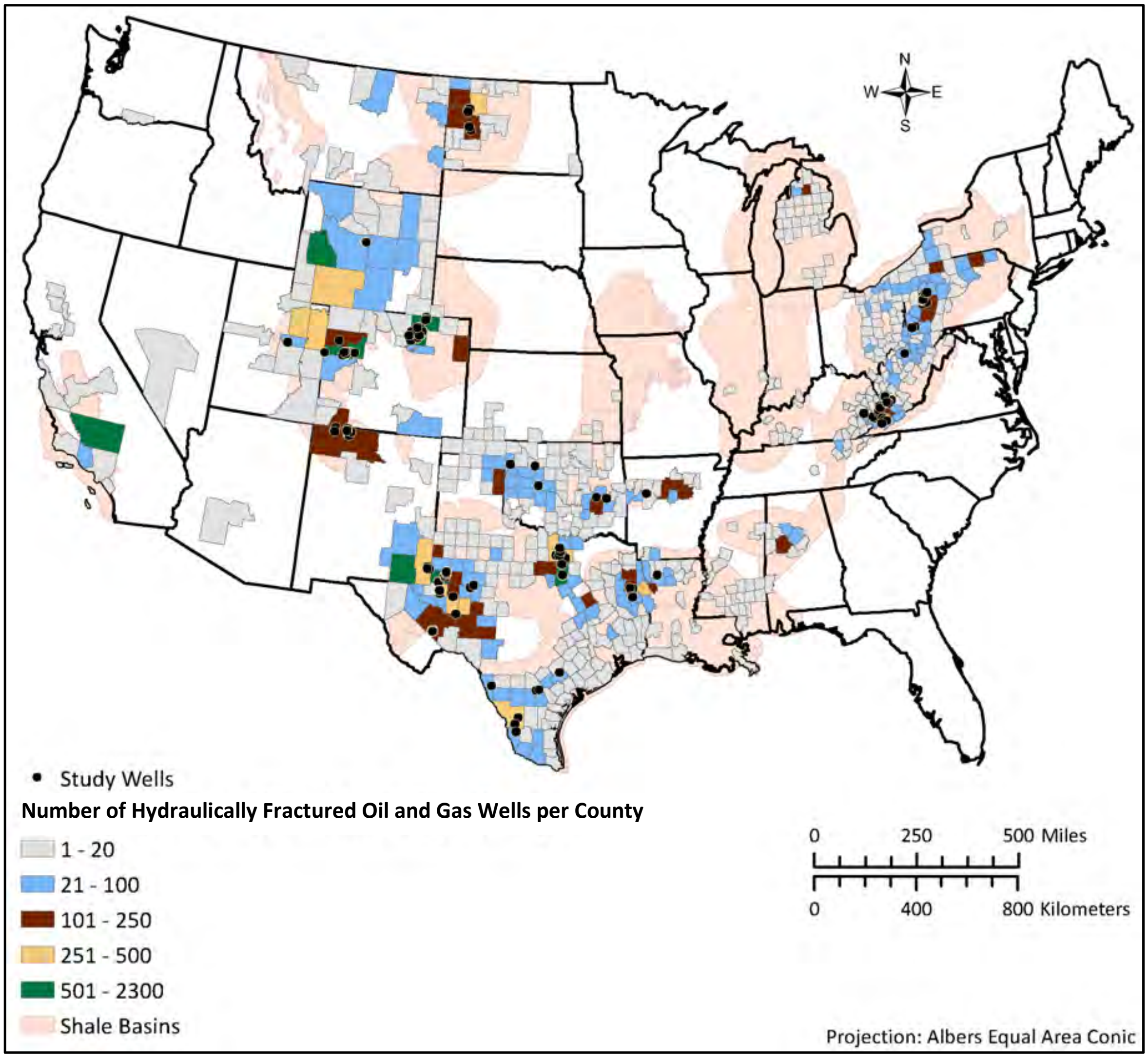

Figure 5. Locations of the 323 study wells. The study wells were selected from a list of wells that were reported by nine service companies to have been hydraulically fractured between approximately September 2009 and September 2010. County-level well densities from the service company well list are shown for comparison. Fewer than 20 well identifiers were reported in Alaska; no study wells were located in Alaska.

Some of the data received were claimed as confidential business information under the Toxic Substances Control Act. Through two separate letters (sent in August 2012 and September 2013), the EPA worked with the operators to summarize and present the data in this report in a way that protects their claims of confidentiality.[43]

3.4. Data Extraction and Analysis

This report summarizes data from two of the five topic areas included in the information request (geologic maps and cross sections, and drilling and completion information) and includes some

[43] Non-confidential business information provided by the well operators is available at http://www.regulations.gov/#!searchResults;rpp=10;po=0;s=epa-hq-ord-2010-0674.

Table 2. Comparison between well identifiers from the service company well list and the 323 study wells. Well identifiers were assigned to geographic areas defined by shale plays, shale play clusters, or no shale play. Wells assigned to these geographic areas are not assumed to produce oil and gas from the assigned shale play(s). "NA" indicates not applicable.

Geographic Region	Geographic Area (Shale Plays or Shale Play Clusters)	Number of Well Identifiers	Number of Study Wells
East	Antrim	262	
	Marcellus	3,484	50
	New Albany	23	
South	Avalon-Woodford	1,634	34
	Barnett	2,939	33
	Bend	<10	
	Eagle Ford	860	<10
	Excello-Mulky	40	
	Fayetteville	873	14
	Floyd-Chattanooga	273	
	Haynesville-Bossier	1,383	<10
	Tuscaloosa	24	
	Woodford-Caney	606	<10
West	Bakken	778	<10
	Cody	<10	
	Gammon	40	
	Hermosa-Mancos	864	<10
	HilliardBaxterMancos-Niobrara	1,096	<10
	Lewis	320	17
	Monterey	726	
	Mowry	76	
	Niobrara Fm	2,288	56
	Niobrara-Mowry	121	
	Pierre-Niobrara	50	
Other	NA	6,161	91
Total	NA	24,925	323

information from a third topic area (hydraulic fracturing procedures and reports).[44] Data were extracted from various documents contained in the well files, including driller's reports,[45] wellbore diagrams, maps, and completion reports (Table 3). Data obtained from the well files were also used to calculate or determine other values, including cement bond indices and some stimulated lithologies. The extracted and calculated data were recorded and organized in a database that was then used to develop the figures and tables presented throughout this report.

[44] Information collected about environmental releases was used in the EPA's *Review of State and Industry Spill Data: Characterization of Hydraulic Fracturing-Related Spills* (US EPA, 2015).

[45] Driller's reports are daily logs of the activities at a well and include details on the well's drilling, casing, and cementing history from surface to total depth.

Table 3. Summary of data elements generally obtained from well files provided by oil and gas well operators. Data used in this study were either extracted directly from an information source or calculated using data provided in the information sources.

Data Element	General Information Source(s)	Extracted or Calculated
Well Characteristics		
Well location	Maps, plats, state oil and gas agency websites	Extracted
Production type	Completion reports, state oil and gas agency websites	Calculated / Extracted
Wellbore orientation	Driller's reports, wellbore diagrams, deviation surveys, state oil and gas agency websites	Calculated / Extracted
Well depth	Driller's reports, deviation surveys	Calculated / Extracted
Perforation locations and purpose	Driller's reports, completion reports	Extracted
Stimulated lithology	Open hole logs, mud logs	Calculated / Extracted
Construction Characteristics		
Casings used and depth	Driller's reports, wellbore diagrams, casing tallies	Extracted
Primary cement used behind casing	Driller's reports, cementing tickets	Extracted
Secondary cement used behind casing	Driller's reports, cementing tickets, completion reports	Extracted
Location of cemented intervals behind casing	Driller's reports, wellbore diagrams, cement evaluation logs	Extracted
Cement bond index	Cement bond logs	Calculated
Well completion type (cemented, formation packer, open hole)	Driller's reports, wellbore diagrams	Extracted
Ground Water Resources		
Depth of protected ground water resources	State/Federal well authorization documents, aquifer maps*	Extracted
Location of private drinking water wells	Complaint reports, spill reports	Extracted

* Table 5 provides additional details on the types of information provided by well operators with respect to the depths of protected ground water resources.

3.4.1. Well Characteristics

To better understand the kinds of oil and gas production wells that were hydraulically fractured, the following information was identified for each well: well age, production type, well orientation,[46] true vertical depth, measured depth at the point of shallowest hydraulic fracturing, and stimulated lithologies. Together, these characteristics provide insight into the variability among oil and gas production wells hydraulically fractured by nine service companies in 2009 and 2010.

Well Age. Well age was calculated by comparing the spud date (i.e., the date the first hole was drilled) to the last date in the study's timeframe, September 30, 2010. This provided an estimate of the age of the well at the time of the hydraulic fracturing event that occurred within the timeframe of the EPA's service company well list (hydraulically fractured between approximately September 2009 and September 2010).

Production Type. Production type was determined based on the ratio of initial production volumes of oil and gas. In most cases, initial production data were provided in the well files; wells with gas-to-oil ratios greater than 20,000 cubic feet of gas per barrel of oil were considered "gas" wells [US Geological Survey (USGS), 2012]. Approximately 14 percent of the well files did not contain initial production data. In these cases, production types were determined from other sources of information in the well file or classifications provided by state websites.

Well Orientation. Wells were classified as either vertical, horizontal, or deviated based on information from driller's reports, wellbore diagrams, and deviation surveys. For this study, "vertical" wells were defined as wells with a bottom-hole location within 500 lateral feet of the surface wellhead location. "Horizontal" wells were defined as wells intentionally completed with one or more boreholes drilled laterally to follow the targeted geologic formation. "Deviated" wells were defined as non-horizontal wells with a bottom-hole location more than 500 lateral feet from the surface wellhead location. For example, deviated wells may have an "S" shape, starting and ending relatively vertical, but with an intermediate portion drilled at a significant angle, or they may have a relatively constant angle along the entire drilled length.

True Vertical Depth. The true vertical depth of a well is defined as the vertical depth at the bottom-most point of the well. True vertical depth was determined from driller's reports, wellbore diagrams, deviation surveys, and state websites. Often this value had been calculated during drilling and was extracted from driller's reports. In some instances, this value was calculated by the EPA using trigonometry, given the wellbore length as well as the angle of deviation from vertical, and by assuming a fairly straight wellbore.

Measured Depth at the Point of Shallowest Hydraulic Fracturing. 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. The measured depth of the shallowest

[46] In this study, well orientation refers to the degree a well diverges from vertical, not the ordinal direction (e.g., north or south) of the bottom-hole location relative to the wellhead.

point of hydraulic fracturing was identified to determine the shortest distance along the wellbore between hydraulic fracturing and operator-reported depths to protected ground water resources.

In cemented cased completions, the point of shallowest hydraulic fracturing was equal to the shallowest measured depth of a production perforation used for hydraulic fracturing. In uncemented cased completions, the point of shallowest hydraulic fracturing was equal to the measured depth of the shallowest formation packer used to isolate a hydraulic fracturing interval. In open hole completions, the point of shallowest hydraulic fracturing was equal to the uppermost measured depth interval where hydraulic fracturing occurred.

Hydraulically Fractured Lithologies. For this report, hydraulically fractured lithologies are geologic formations that were hydraulically fractured at any point in the well's history. Open hole logs, in combination with mud logs, were reviewed to determine zone lithology using accepted principles and methods, such as those described in Dewan (1983), Krygowski (2004), and Schlumberger (1991). When these log types were not available, hydraulically fractured lithologies were identified from other data sources in the well files that included a lithologic description of the zone hydraulically fractured.

3.4.2. Construction Characteristics

Data on casing, cementing, and completion activities for each hydraulically fractured well were compiled from information included in the well files (Table 3).

Casing. Casing strings were identified from reported casing tallies, driller's reports, completion reports, wellbore diagrams, and occasionally from forms submitted to oil and gas regulatory agencies. The measured depths of the top and bottom of the casing string were recorded for surface, intermediate, and production casing. Conductor casing or other shallow, often uncemented casings, were excluded.

Cement. Cement placement behind surface, intermediate, and production casing was determined from various sources, including cement evaluation logs,[47] driller's reports, cement job tickets, wellbore diagrams, and forms submitted to oil and gas regulatory agencies. Cement tops were determined from cement evaluation logs, when available. If cement evaluation logs were unavailable, other reported data, including driller's reports, cement job tickets, wellbore diagrams, and forms submitted to oil and gas regulatory agencies were assessed collectively to determine cement tops. Cement bottoms were identified using the point of placement of cement through the casing.

Cement Bond Indices. Cement bond indices, i_b, were calculated from standard acoustic cement bond logs using a straight-line formula derived from the semi-log plot representing the Tenneco/Fitzgerald technique, which relates amplitude and bond index, as outlined in Fitzgerald et al. (1985) and Smolen (1996):

[47] Cement evaluation logs included standard acoustic cement bond logs, ultrasonic image tool logs, and temperature logs.

$$i_b = \frac{\log A(d) - \log A(0)}{\log A(100) - \log A(0)} \quad (1)$$

In equation 1, $A(d)$ is equal to the measured amplitude at depth d, $A(0)$ is equal to the maximum amplitude recorded on the log and represents a point of zero bonding (i.e., free pipe), and $A(100)$ is equal to the minimum amplitude recorded on the log and represents the point of best bonding. Thus, i_b can take on values from 0 to 1. A value of 0 indicates the weakest bonding, while a value of 1 indicates the strongest point of bonding measured in the well (Smolen, 1996).

The bond index was calculated at 10 foot intervals for the first 100 feet immediately above the point of shallowest hydraulic fracturing (if that part of the wellbore was logged) and at 50 foot intervals for the remaining up-hole portion of the log.

3.4.3. Drinking Water Resources

A geospatial analysis of surface features related to surface and ground water resources was conducted to summarize the spatial relationship of drinking water resources to oil and gas production wells hydraulically fractured by the nine service companies.[48] Additional information on ground water resources in the immediate area of the study wells was obtained from data supplied by well operators.

Geospatial Analysis of Water Resources. The locations (latitude/longitude coordinates) of the 323 wells were used to identify water resources near hydraulically fractured oil and gas production wells. Coordinates were obtained in either the North American Datum of 1927 (NAD27) or North American Datum of 1983 (NAD83). All NAD27 coordinates were transformed to NAD83 coordinates using an ArcGIS built-in utility that follows the NADCON model (2011) and plotted using ESRI's ArcGIS v.10 software (2010).

A 0.5 mile radius circle was delineated around each surface wellhead location (referred to as a "well buffer") using an Albers Equal Area projection appropriate for the continental United States.[49] The 0.5 mile radius around each wellhead location provided a consistent approach to search for nearby water resources, although local topographical conditions might support use of a different geometry at any specific well site. Individual well buffers were compared to available spatial data identifying the presence of surface and ground water resources as well as current drinking water resources. Surface water resources (e.g., streams and lakes) were obtained from the United States Geological Survey's National Hydrography Dataset and used to calculate the total stream length and area of open water in each buffer (USGS, 2014). This report does not identify whether surface water resources currently serve as drinking water resources. The presence or absence of current drinking water resources was determined using locations of public water system wells and surface water intakes (US EPA, 2014a), as well as private drinking water wells identified in the well files.

[48] The EPA's *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* defined "drinking water resources" as any body of water, ground or surface, that currently serves or in the future could serve as a source of drinking water for public or private water supplies (US EPA, 2011).

[49] Central Meridian: -96, Standard Parallel 1: 29.5, Standard Parallel 2: 45.5, Latitude of Origin: 37.5.

Protected Ground Water Resources. Since depths to protected ground water resources were not included in most well files, well operators were asked to provide this information for each well location in September 2013. As noted by the Ground Water Protection Council:

> "There is a great deal of variation between states with respect to defining protected ground water. The reasons for these variations relate to factors such as the quality of water, the depth of Underground Sources of Drinking Water, the availability of ground water, and the actual use of ground water." (GWPC, 2009)

As a result, the identification of protected ground water resources relied solely on information provided to the EPA by well operators. To better understand the data provided by the well operators, the EPA also asked them to identify the source of the depths they provided.

Some operators reported protected ground water resources, while other operators provided the depth to ground water resources without identifying whether the resource was protected. Operator-provided depths were assumed to be depths to protected ground water resources. Data sources used by operators to identify protected ground water resources generally included state or federal regulations or permit requirements, state or federal ground water maps or databases, and well records from nearby water wells or oil and gas production wells. Well records included either: (1) depths of nearby water supply wells, or (2) depths of freshwater zones identified by operators during drilling or from induction logs. Reported depths to ground water resources included both specific values (e.g., surface to 200 feet) and estimates (e.g., no deeper than 200 feet). Based on the information provided, the EPA did not identify any cases in which water samples were collected before or after drilling to determine whether water from a specific zone or found at a specific depth met designated protected water quality criteria.

Operator-provided depths to protected ground water resources are compared to different well construction characteristics in Section 4.3.2. Using depths based on different definitions of protected ground water resources would likely affect the results presented in Section 4.3.2.

3.5. Estimates of Well Design and Construction Characteristics

Each analysis presented in this report used data collected from 323 study wells to estimate the frequency of occurrence of well design and construction characteristics, which can be used to better understand onshore well design and construction practices in the United States. Estimates are presented at the national level[50] and are statistically representative of the oil and gas production wells hydraulically fractured by the nine service companies.[51] As described in Section 3.1., the service company well list likely resembled the overall geographic distribution of oil and gas

[50] As described in Section 3.2, study wells were selected from the service company well list, which contained county and state locations of well identifiers and well operator names. It was not possible to choose a representative sample of wells based on hydraulically fractured geological formations, because these data were not included in the service company well list. Consequently, results specific to individual targeted geologic formations were not calculated. Results calculated for individual targeted geologic formations would have larger 95 percent confidence intervals than the results from analyses conducted for this report.

[51] The survey design ensured that the 323 study wells were statistically representative of all wells on the service company well list, regardless of state.

production in the United States in 2009 and 2010. The estimates presented in the report, therefore, are likely indicative of well design and construction characteristics of onshore oil and gas production wells hydraulically fractured across the continental United States during the timeframe examined in this study.

In general, each of the 323 wells was assigned to a category (or characteristic) defined by a given analysis. Statistical weights were then used to estimate the number of wells out of the sampled population that were within each category (i.e., point estimates). Ninety-five percent confidence intervals were calculated for each point estimate, as described in Appendix A.[52]

Statistical Weights. Each study well carried a statistical weight equal to the number of wells it represented on the service company well list. Statistical weights ranged from 4 to 190. Therefore, each study well represented between 4 and 190 hydraulically fractured oil and gas production wells on the service company well list. The sum of the statistical weights for the 323 study wells was 23,195.

Statistical weights were calculated from the probability of a well identifier being chosen in the two-stage stratified selection process and being retained when 50 well identifiers were randomly removed from the 400 selected well identifiers (Section 3.2). Additional adjustments to the weights were made to account for: (1) operators with fewer than 10 well identifiers on the service company well list,[53] (2) a change in the number of unique wells in the original service company well list,[54] and (3) one well identifier, noted in Table 1, that was misidentified and is not a well from one of the nine sampled operators.

To the extent that wells operated by the same company in the same geographic area had similar well histories, the survey design ensured that point estimates were more precise. Also, to the extent that wells from companies of similar sizes and, for large companies, geographic regions, had similar well design, construction, and hydraulic fracturing characteristics, there is further improvement in the precision of the results. Point estimates are more precise and smaller confidence intervals occur, therefore, when more wells share similar characteristics.

[52] The algorithm used to design the sample was optimized to provide the smallest 95 percent confidence interval for the sample of 350 well identifiers selected from the service company well list. Confidence intervals reflect observed variability in well design and construction characteristics. This variability may be associated with different company policies, geology, state requirements, or other factors. The point estimate is the center of the confidence interval and represents the best estimate of the true number of wells in a category given this sample of hydraulically fractured oil and gas production wells.

[53] The statistical weights for wells from the small operators were adjusted so that they represented themselves and wells from operators that had fewer than 10 well identifiers. This assumed that wells from the three sampled small operators had similar characteristics to wells operated by companies with fewer than 10 well identifiers on the service company well list. To the extent that differences in characteristics existed, this is not reflected in survey estimates. Since these very small companies operated less than 10 percent of all well identifiers (2,352 out of 24,925), the potential for biased estimates was limited.

[54] The number of wells in the original population decreased from 24,925 to 24,019 after further review of the data provided by the nine hydraulic fracturing service companies identified duplicate entries.

3.6. Quality Assurance and Quality Control

The EPA does not make any claims on the quality or accuracy of the data or information received directly from the operators in response to the information request. In a few, limited cases, discrepancies between data publicly available through state websites and operator-provided data were observed. In these cases, data provided by the well operators were used. A comprehensive comparison of operator-provided data and data available through state websites was not conducted.

Extracted data for all wells and calculated data for up to two example wells were shared with the well operators in September 2013. In total, 20,203 data elements were provided to the operators for their review. Operators identified changes to 774 data elements (less than 4 percent). Some of these changes were corrections to extracted or calculated data; in many cases, the operators provided additional data that were not found in the original submissions. All updates provided by the operators were incorporated.

Quality assurance and quality control measures were used to ensure that data in the database were of sufficient quality for analysis and that the analyses performed were conducted properly. The quality of the data extraction process was tested in two ways: (1) re-reviewing portions of the well files and (2) designing queries to detect inconsistencies in the database. Inconsistencies found while querying the database were resolved by referring to the original data provided by the operators.

At least 10 percent of records from each operator relating to well location, cementing records, and cement bond logs were re-reviewed, and 100 percent of driller's reports were re-reviewed. No differences in well location and cementing records were identified. Any differences found in the re-review of the driller's reports were resolved through discussions with the original reviewer.

Cement bond indices were calculated for 203 wells for which standard acoustic cement bond logs were provided. Cement bond logs from 30 wells were randomly selected for re-review. Among these wells, a total of 2,721 cement bond indices at different measured depths were re-calculated (Section 3.4.2). In 64 instances (2.4 percent of the re-reviewed cement bond indices) from 7 wells, the re-reviewed cement bond index was different from the original value by 0.05 or more bond index points. The maximum error, which occurred one time, resulted in a difference of 0.64 in the calculated bond index. The causes of these differences are summarized in Table 4.

Cement bond indices from all wells were used to calculate the distribution of cement bond indices at discrete heights above the shallowest point of hydraulic fracturing (Section 4.2.2). The distribution of cement bond indices at each height is based on data from at least 22 distinct wells, with the most populous height (350 feet) having cement bond indices from 185 distinct wells. The number of incorrect cement bond indices at any given height was determined to be between one (for heights with 22 wells) and four (for heights with 185 wells), assuming that the 2.4 percent overall error rate calculated in Table 4 was evenly distributed across the number of cement bond

Table 4. Quality assurance summary for calculated cement bond indices. There were four instances in which two of these types of errors were made in calculating the same cement bond index, explaining how 68 occurrences of error resulted in 64 erroneous calculated bond indices. "NA" indicates not applicable.

Description	Occurrences	Error Rate	Range of Errors in Calculated Bond Index
Different values chosen for A_{100} or A_0	43	1.6%	0.0504 – 0.3673
Different interpolations of the amplitude value	12	0.4%	0.0520 – 0.3413
Misunderstanding of the scale on the cement bond log	9	0.3%	0.0538 – 0.6402
Incorrect inclusion of amplitude values that were affected by a casing collar	4	0.1%	0.0697 – 0.0970
Overall error rate	*68*	*2.4%*	*NA*

indices calculated at each particular height.[55] Conservatively applying the maximum error of 0.64 in the calculated bond index to between one and four calculated bond indices would move the erroneous values toward (or away from) one of the extreme ends of the range of calculated bond indices, depending on whether the error is added or subtracted. While, for a single point, the 0.64 error is large, its occurrence rate is small (less than 0.04 percent of 2,721 cases). Therefore, factoring in this error would have a minor impact on the distributions presented in Section 4.2.2.

This work was conducted following the methods and procedures contained in the project-related quality assurance project plans (The Cadmus Group, 2013; US EPA, 2013b, 2014c; Westat, 2013). The project underwent a series of technical systems audits by the designated EPA Quality Assurance Manager between April and August of 2012. No corrective actions were identified.

4. Analytical Results

Well design and construction characteristics for an estimated 23,200 (95 percent confidence interval: 21,400-25,000) onshore oil and gas production wells hydraulically fractured by nine service companies in 2009 and 2010 are summarized below. Throughout the remainder of this report, figures show point estimates with 95 percent confidence intervals. Data tables and in-text calculations report rounded point estimates and 95 percent confidence intervals.

4.1. Well Characteristics

Age, Production Type, and Orientation. The nine service companies hydraulically fractured both recently drilled wells and older wells, oil and gas wells, and wells of different orientations (Figure 6).

Most of the wells were drilled within 10 years of the end of the study's timeframe (September 30, 2010). An estimated 1,400 wells (600-2,200) were drilled more than 10 years before the end of the

[55] For example, the most populous height has calculated cement bond indices from 185 wells. Multiplying 185 by the error rate, 0.024, results in 4.44 (which rounds to 4.0).

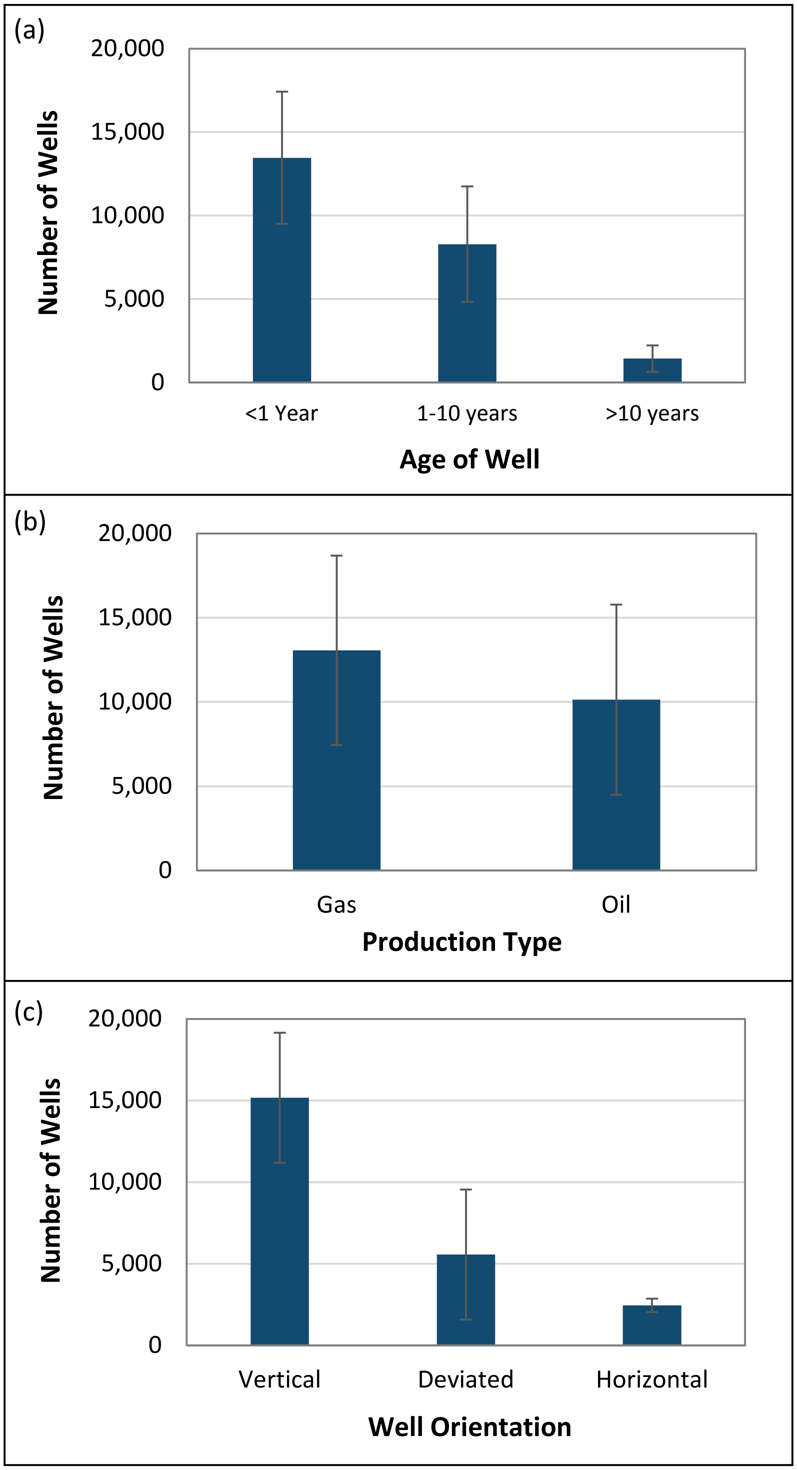

Figure 6. (a) Age, (b) production type, and (c) orientation of oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Well age was calculated by comparing the spud date (i.e., the date the first hole was drilled) to the last date in the study timeframe, September 30, 2010. Error bars display 95 percent confidence intervals.

study's timeframe, with the oldest well among the study wells spudded in 1959.[56] The presence of older wells suggests that either targeted geologic formations accessed through existing oil and gas production wells were re-fractured or that existing oil and gas production wells were recompleted using hydraulic fracturing to recover oil and gas from hydrocarbon-containing formations previously drilled through.

An equal proportion of oil and gas production wells were hydraulically fractured. An estimated 13,100 wells (7,400-18,700) initially produced gas, while an estimated 10,100 wells (4,500-15,800) initially produced oil (panel b in Figure 6). More than half of the wells (15,200; 11,200-19,200) in this study were vertical wells, with fewer deviated and horizontal wells (panel c in Figure 6).

Depths. True vertical depths ranged from less than 2,000 feet to greater than 11,000 feet. The majority of wells had a true vertical depth greater than 5,000 feet (Figure 7). Among the study wells, the shallowest well had a true vertical depth of just over 1,600 feet, while the deepest well had a true vertical depth slightly greater than 13,000 feet.

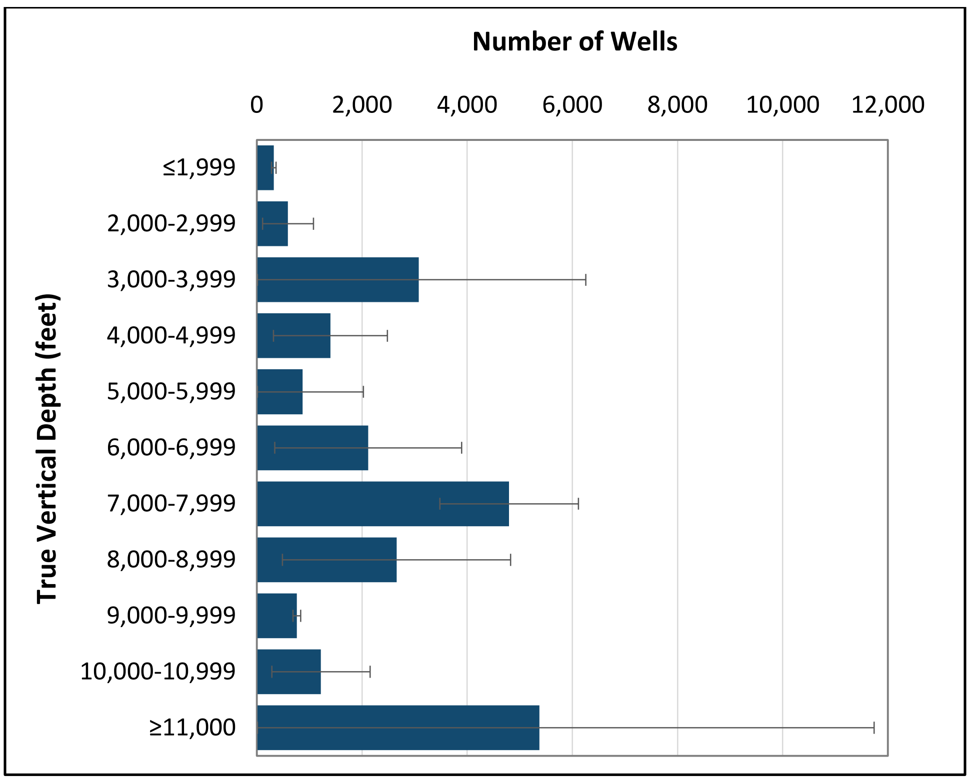

Figure 7. True vertical depths of oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. True vertical depth is defined as the vertical depth of the bottom-most point of the well. Error bars display 95 percent confidence intervals.

[56] Instances in this report that refer to oldest, deepest, or other extreme values from among the 323 study wells should not be interpreted to mean that these are the most extreme values among the 23,195 wells in the sampled population, since it is unlikely that the sample of 323 study wells happened to include the most extreme values from the 23,195 wells. For this example, 1959 is the year when the oldest well from among the 323 study wells was drilled, but there are likely older wells in the population of 23,195 oil and gas production wells that were hydraulically fractured by nine service companies between approximately September 2009 and September 2010.

The depth at which hydraulic fracturing is conducted is different than the true vertical depth of a well, because hydraulic fracturing typically occurs within a specific portion of the well. Hydraulic fracturing depths were identified using the measured depth of the shallowest point at which hydraulic fracturing occurred. Measured depths of hydraulic fracturing ranged from less than 1,000 feet along the length of the well to more than 11,000 feet along the length of the well (Figure 8). More than half of the wells had points of shallowest hydraulic fracturing deeper than 5,000 feet below the wellhead, as measured along the length of the well. The shallowest point of hydraulic fracturing in the study wells was recorded at a measured depth of roughly 600 feet, and the deepest point of shallowest hydraulic fracturing was found to be at a measured depth of approximately 13,500 feet.

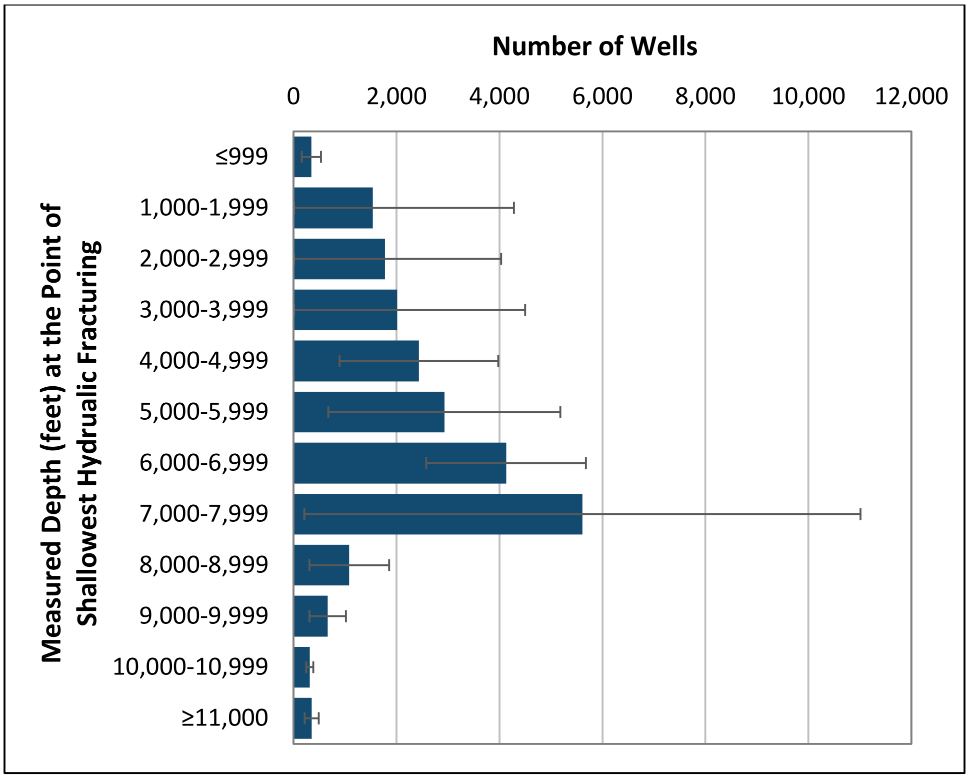

Figure 8. Measured depths of the point of shallowest hydraulic fracturing in oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. The measured depth is the distance along the length of the well and is not always equal to the true vertical depth. The point of shallowest hydraulic fracturing is the uppermost depth interval where hydraulic fracturing occurred. Error bars display 95 percent confidence intervals.

Hydraulically Fractured Lithologies. Hydraulic fracturing is used to enhance oil and gas production from many different types of lithologies, or rock formations. Lithologies hydraulically fractured by the nine service companies included sandstone, shale, carbonate, coal,[57] and chert (Figure 9).

[57] This included coalbed methane production wells. Unlike gas production from tight sands and shales, coalbed methane production typically occurs after sufficient connate water is removed to release methane from coal seams (Christen, 2003; US EPA, 2004). Because hydraulic fracturing was used to stimulate methane production from these wells, they are included in this study.

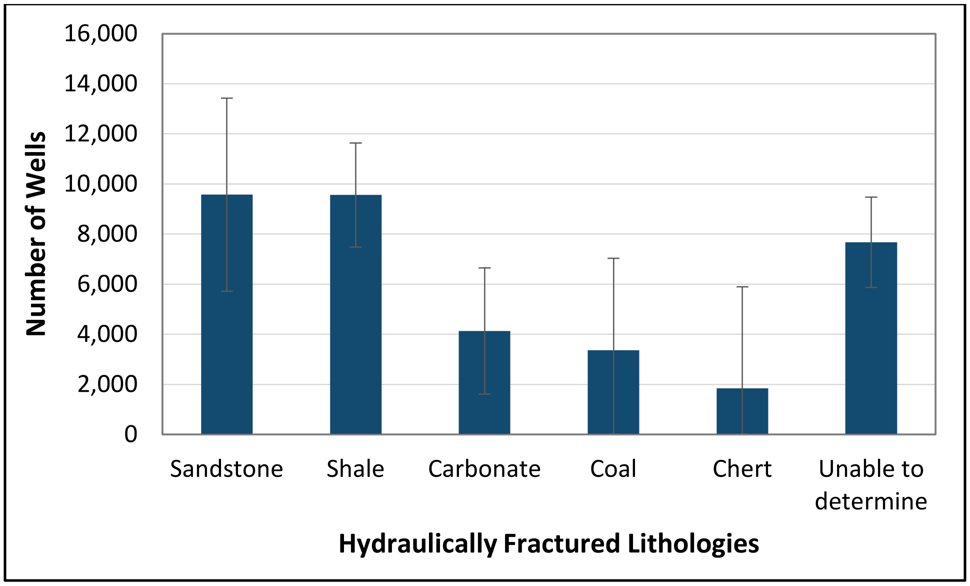

Figure 9. Lithologies hydraulically fractured for oil and gas by nine service companies between approximately September 2009 and September 2010. An estimated 8,100 wells (5,400-10,800) had one hydraulically fractured lithology, and 9,000 wells (6,100-11,900) had more than one lithology hydraulically fractured. Wells with insufficient information to determine hydraulically fractured lithologies are represented by the "unable to determine" bar. Error bars display 95 percent confidence intervals.

An estimated 8,100 wells (5,400-10,800) had one lithology hydraulically fractured, while 9,000 wells (6,100-11,900) had more than one hydraulically fractured lithology. Hydraulically fractured lithologies could not be identified for 7,700 wells (5,900-9,500) due to insufficient data in the well files. Because hydraulic fracturing occurred in different lithologies within the same well (depending on the stratigraphic layering in the area), the number of wells displayed in Figure 9 is greater than the total number of wells identified in this study (i.e., wells could be counted more than once in this analysis).

4.2. Construction and Completion Characteristics

Oil and gas production wells are constructed in sequential stages using casing and cement, as described in Section 2. Casing and cement allow a desired flow to take place in a controlled fashion and create zonal isolation. Wells represented in this study were completed in the targeted geologic formation with an open hole or with casing secured to the formation using either cement or formation packers (Figure 3). An estimated 20,200 wells (17,500-23,000) had cemented casing completions, while 1,500 wells (1,400-1,600) had formation packer completions; another 1,500 wells (10-4,800) had open hole completions.

4.2.1. Casing Installation

Oil and gas production wells in this study had between one and three casing strings (excluding conductor casing), as illustrated in Figure 2. An estimated 23,200 wells (21,400-25,000) had surface casing, while 9,100 wells (2,900-15,400) had intermediate casing and 21,900 wells (19,200-24,600) had production casing. The most common casing configuration, used in 12,800 wells (7,600-18,000), was a surface and production casing. Another 8,100 wells (2,300-13,900) had a surface, intermediate, and production casing.[58] Together, these two casing configurations accounted for nearly all of the production wells in this study.

Measured depths of the bottom of surface, intermediate, and production casings are shown in Figure 10. The range of measured depths for each type of casing is larger for deeper casings. For example, the measured depths of surface casing ranged from less than 1,000 feet to between 6,000 and 6,999 feet, while the measured depths of production casing ranged from less than 1,999 feet to greater than 15,000 feet. The median measured depths of the bottom of surface, intermediate, and production casing were calculated to be 800, 5,000, and 8,000 feet, respectively.

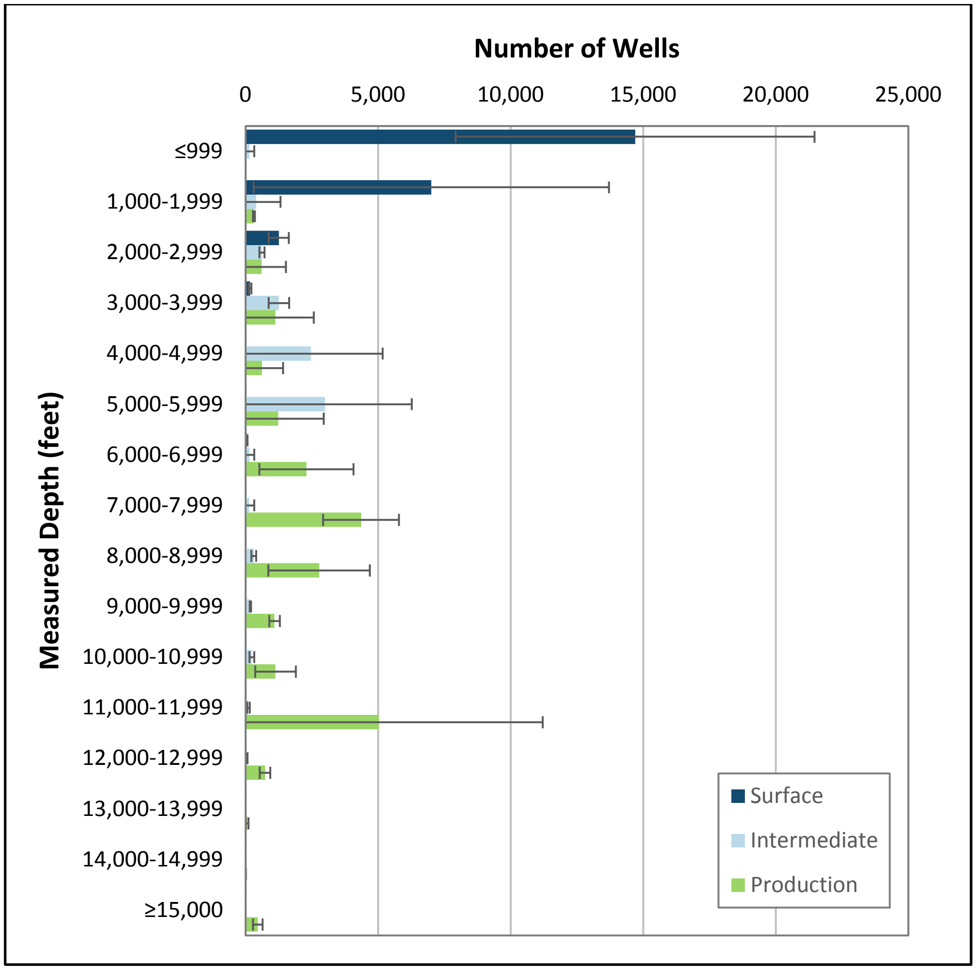

Figure 10. Measured depths of the bottoms of surface, intermediate, and production casing in oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Not all wells had all types of casing: 23,200 wells (21,400-25,000) had surface casing, 9,100 wells (2,900-15,400) had intermediate casing, and 21,900 wells (19,200-24,600) had production casing. Error bars display 95 percent confidence intervals.

58 This excludes the casing configurations shown in Figure 2 that included liners.

An estimated 52,800 casing strings (45,800-59,700) were cemented.[59] These casing strings were cemented to the wellbore through either primary or secondary cementing operations (Figure 11). Primary cementing operations occur at the time the well is drilled and constructed, with the cement being delivered from the surface down through the casing, passing around the casing shoe (i.e., the bottom of the casing), and moving upward into the annular space behind the casing. An estimated 48,300 (38,500-58,100) of all cement placement methods for cemented casings were primary cementing operations. This included instances where cement staging tools were used at the time the casing was originally cemented (i.e., multi-stage cementing operations).

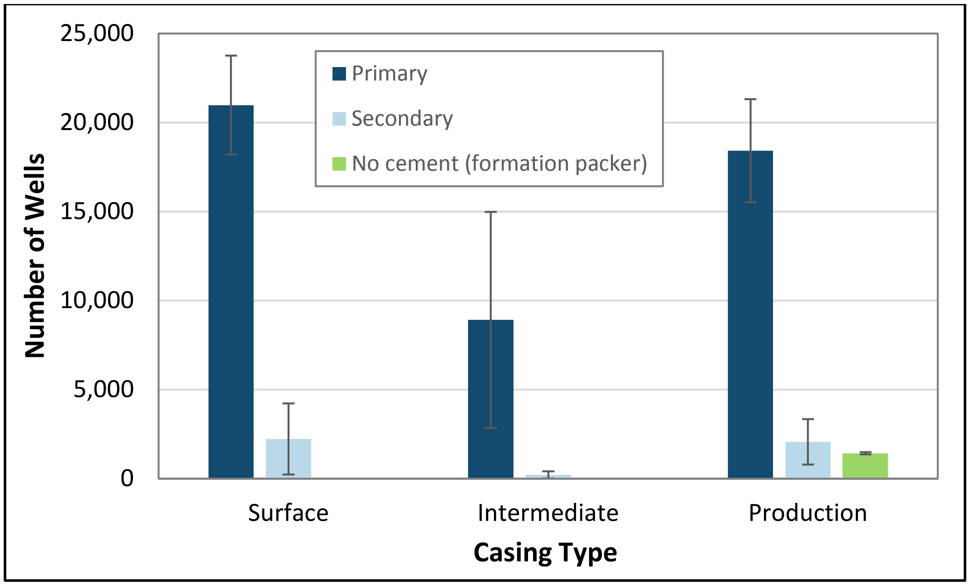

Figure 11. Type of cementing operation conducted for each casing type found in oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Primary cementing operations occurred at the time the well was drilled and constructed. Secondary cementing operations were considered to be any non-primary cementing operation. Casings with "no cement" were not designed to have cement placed, because the wells were completed using formation packers. Error bars display 95 percent confidence intervals.

Secondary cementing operations,[60] which can occur at various times following primary cementing, accounted for an estimated 4,500 (1,500-7,500) of all cement placement methods for cemented casings. For this analysis, secondary cementing operations were considered to be any non-primary cementing operation and included cement squeezes, use of cement baskets, and pumping cement down the annulus. Reasons for secondary cementing operations were not always clearly stated in the well files; however, contextual information from the well files was used to identify situations addressed through secondary cementing operations. Types of situations included: (1) adding cement to fracture a different zone, (2) plugging open perforations that were no longer wanted, (3) placing cement behind casing when primary cementing operations had failed to place it to a desired

[59] An estimated 54,200 casing strings (47,300-61,200) were installed using cement or packers.

[60] Secondary cementing operations are typically referred to as "remedial" cementing operations (Nelson and Guillot, 2006; Schlumberger, 2014).

height, and (4) sealing off a formation thought to contribute to pressure detected in an uncemented annulus between the wellbore and the casing.

Figure 12 displays the number of wells that had fully cemented, partially cemented, and uncemented casings, by casing type (surface, intermediate, or production). Fully cemented casings were defined, in this study, 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).[61] Conversely, 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. 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.

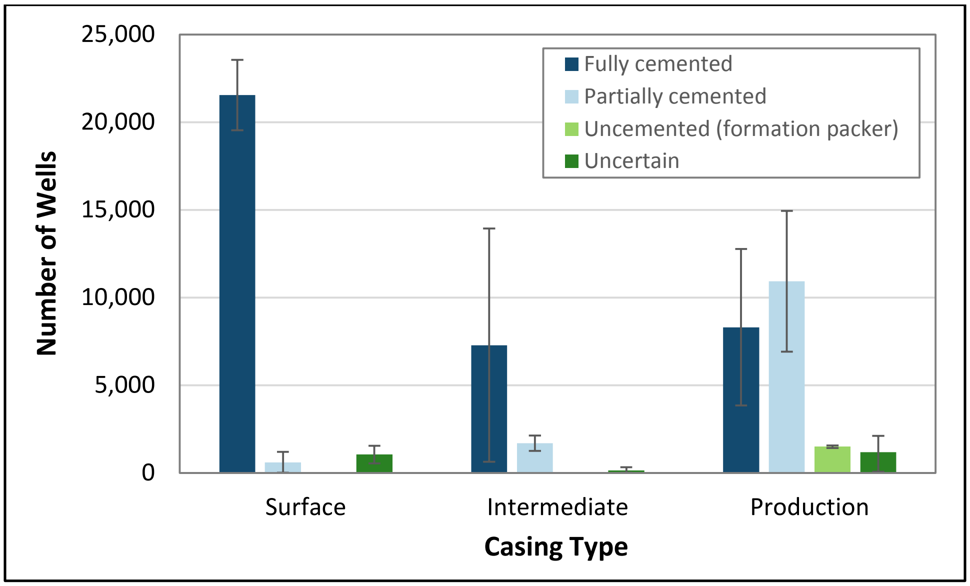

Figure 12. Degree of cementing determined for each casing type found in oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. The presence or absence of cement was evaluated from the bottom of the casing to either the ground surface or the next larger and overlying casing. Fully cemented casings were defined, in this study, as casings that had a continuous cement sheath over the distance evaluated. Partially cemented casings were defined as casings that had some portion of the casing that was cemented over the distance evaluated, but were not fully cemented. Uncemented casings were not designed to have cement placed, because the wells were completed using formation packers. Due to a lack of sufficiently detailed cement information in the well files, it could not be determined if some casings were fully cemented or partially cemented; this is reflected by the “uncertain” category. Error bars display 95 percent confidence intervals.

Figure 12 shows that surface and intermediate casings were fully cemented in most wells, while production casings were generally either fully or partially cemented. An estimated 21,500 wells (19,500-23,600) had fully cemented surface casing, and 7,300 wells (600-13,900) wells had fully cemented intermediate casings. Production casing was fully cemented in 8,300 wells (3,800-

[61] Continuous cement sheaths were defined by the presence of cement, which was based on the determination of cement tops and bottoms (Section 3.4.2). This analysis does not incorporate cement quality derived from cement evaluation logs.

12,800) and partially cemented in 10,900 wells (6,900-14,900). Also shown in Figure 12 are formation packer completions, which, by design, had uncemented production casings. Open hole completions are not shown. Due to a lack of sufficiently detailed cement information in the well files, it could not be determined if some casings were fully or partially cemented; this is reflected by the “uncertain” category in Figure 12.

An estimated 6,800 wells (1,600-11,900) were fully cemented along the outside of the well, from the bottom of the well to ground surface. In these wells, all casing strings had a continuous sheath of cement from the bottom of each casing to either the surface or into the next overlying casing. Approximately 15,300 wells (10,500-20,100) had one or more uncemented intervals along the outside of the well, from the bottom of the well to the ground surface. Partially cemented casing strings (identified in Figure 12) were further examined to determine the proportion of the casing length cemented. Figure 13 displays, for each casing type, the percentage of the evaluated casing length that was cemented and shows that the majority of partially cemented casings had more than 50 percent of the evaluated casing length cemented. Of the partially cemented casings in Figure 13, lengths of uncemented intervals ranged from 5 to 7,800 feet, with a median value of 1,300 feet. Eighty percent of all uncemented intervals behind a single casing were between 100 and 5,300 feet in length (10th to 90th percentiles).

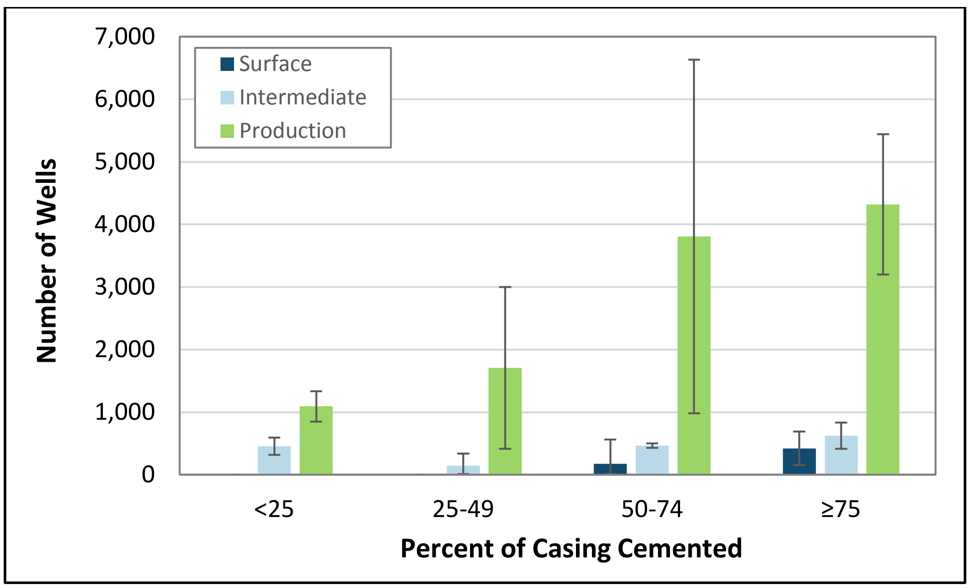

Figure 13. Percentage of the evaluated casing length that was cemented, calculated only for partially cemented casings shown in Figure 12. Error bars display 95 percent confidence intervals.

Uncemented intervals in partially cemented casings can occur when it is technically difficult to return cement to the surface or when casing is expected to be replaced or reused (GWPC, 2014).[62] It can be technically difficult to place cement in zones that: (1) could fracture under the pressures

[62] Many sources recommend that cement be placed across zones containing corrosive fluids, water in need of protection, or hydrocarbons (Nelson and Guillot, 2006; Ross and King, 2007; Smith, 1976), which suggests that there may be uncemented intervals along zones that do not meet these criteria. Criteria for zones not needing to be cemented could not be found.

applied during cementing operations, (2) are highly permeable and relatively under-pressured (e.g., mine voids), (3) cause water loss from the cement slurry, (4) contribute significant fluid into the wellbore, or (5) have poor removal of drilling muds (Holt and Lahoti, 2012; Smith, 1976). It may also be difficult to place cement in zones that are pressurized (Nelson and Guillot, 2006; Schlumberger, 1984; Smith, 1976); this may include gas storage zones and wastewater disposal zones. The occurrence of some of these situations was identified from driller's reports. An estimated 800 (10-1,900) were drilled through a mine void, and 90 wells (50-100) were drilled through either a gas storage zone and/or a wastewater disposal zone. Driller's reports also identified instances of losses of circulation in 1,800 wells (10-3,600).[63] Losses of circulation occur when drilling fluids are lost to surrounding zones and may identify zones in which it could be difficult to place cement (Devereux, 1998).

4.2.2. Cement Evaluation

Once cement has been placed, operators often run one or more logs to evaluate whether the cement formed an effective seal (i.e., cement evaluation logs). An effective seal depends on the full circumferential coverage of the cement around the casing and good bonding between the cement, casing, and wellbore (Brufatto et al., 2003; Devereux, 1998; Holt and Lahoti, 2012). An estimated 18,000 wells (14,900-21,200) had at least one kind of cement evaluation log run, and 5,100 wells (1,300-9,000) had no cement evaluation log run. The most common type of cement evaluation log run was a standard acoustic cement bond log. Other types of cement evaluation logs run included segmented bond, ultrasonic imaging, and temperature logs. Segmented bond logs and ultrasonic imaging logs can provide circumferential cement coverage information, while temperature logs detect the presence or absence of cement in newly-cemented wells.

Standard acoustic cement bond logs, the most common type of cement evaluation log run in the wells represented by this study, are used to evaluate both the extent of the cement placed along the casing and the cement bond between the cement, casing, and wellbore. The logs are run in the cemented casing on an electric wireline and record the attenuation of an emitted acoustic signal as it travels between a sound source and one or more receivers located at a fixed distance from the source. A relatively large recorded amplitude indicates a weaker bond, while a relatively small recorded amplitude indicates a stronger bond. The recorded amplitudes can be used to calculate a cement bond index using the Tenneco/Fitzgerald technique described in Section 3.4.2. (Fitzgerald et al., 1985; Smolen, 1996)

Cement bond indices were calculated for individual study wells at different heights above the point of shallowest hydraulic fracturing and then extrapolated to the sampled population. Figure 14 shows the percentiles of the weighted distributions of all cement bond indices calculated at specific heights above the point of shallowest hydraulic fracturing. In total, the data in Figure 14 represent 15,500 wells (12,300-18,800) in which standard acoustic cement bond logs were run. Each height above the point of shallowest hydraulic fracturing represents between 1,300 wells (200-2,400;

[63] Losses of circulation occurred in an estimated 200 holes (180-210) drilled for surface casing, 140 holes (90-190) drilled for intermediate casing, and 1,300 holes (10-2,900) drilled for production casing. While most volumes of lost drilling fluid were not reported, the maximum reported volume of lost drilling fluids for a single well was greater than 252,000 gallons (6,000 barrels).

5,000 feet above the point of shallowest hydraulic fracturing) and 14,800 wells (11,400-18,200; 350 feet).

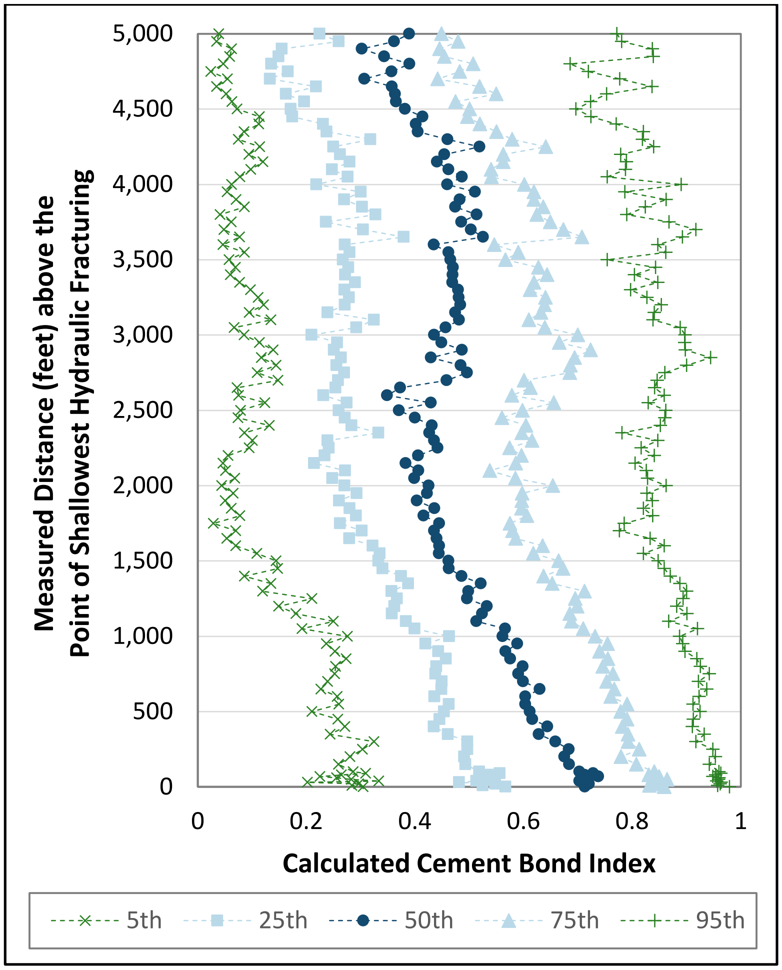

Figure 14. The 5th, 25th, 50th, 75th, and 95th percentiles of cement bond indices calculated from standard acoustic cement bond logs.

Figure 14 shows that the 50th percentile bond index was approximately 0.7 at the point of shallowest hydraulic fracturing and decreased over the next 5,000 feet of overlying measured depth to approximately 0.4. Similar trends were observed for the 5th, 25th, 75th, and 95th percentiles. The calculated cement bond indices shown in Figure 14 depend on the recorded amplitudes (equation 1). There are many conditions that can increase or decrease the amplitude signal. An increased amplitude signal results in a lower cement bond index than actually exists. This has been observed when microannuli are present, when thin cement sheaths (less than 0.75 inches) are present, when the first signals to arrive at the tool pass through acoustically fast formations, and when insufficient time has passed for the cement to cure (Albert et al., 1988; Fitzgerald et al., 1985; Flournoy and Feaster, 1963; Jutton et al., 1991; Pilkington, 1992). A decreased amplitude signal results in a higher cement bond index than actually exists. Conditions that result in decreased amplitude signals include out-of-center positioning of the tool within the casing and casing that is in contact with the side of the wellbore (Albert et al., 1988; Fitzgerald et al., 1985; Flournoy and Feaster, 1963; Nutt, 2012). Other conditions, including those associated with improper tool setting, have been shown to either increase or decrease the recorded amplitude (Albert et al., 1988; Fitzgerald et al., 1985; Jutton et al., 1991).

The presence of the conditions described above were noted, where possible, during reviews of cement bond logs, using the travel time and variable density curves. Two to 27 percent of the cement bond indices in Figure 14 may have been calculated using amplitudes affected by these conditions.[64,65] The true calculated cement bond indices could be either higher or lower, but could not be determined from data in the well files. This type of error likely resulted in a broader distribution of values about the median (Carroll et al., 2006). The trend observed for the 50th percentile in Figure 14 (i.e., a decrease in the calculated bond index further away from the point of shallowest hydraulic fracturing) is unlikely to change due to these errors. These trends suggest that, in general, the quality of the cement bond, as indicated from calculated cement bond indices, was likely to be better near the point of shallowest hydraulic fracturing than at shallower depths. A similar trend was observed by Flournoy and Feaster (1963) and Watson and Bachu (2009). Flournoy and Feaster (1963) state that the best bonding is usually found near the bottom of the casing, with both the percentage and degree of bonding decreasing as the distance from the bottom of the casing increases; they attributed this affect to channeling in the cement due to contamination of the cement by drilling mud in the annulus.

4.3. Well Construction Characteristics and Drinking Water Resources

Characterizing the spatial relationship between surface and ground water resources and oil and gas production wells helps to understand whether hydraulic fracturing could affect the quality of drinking water resources. While proximity alone does not determine impacts, it is a factor that should be considered when assessing the potential for hydraulic fracturing to affect drinking water resources. This section briefly summarizes the spatial relationship of drinking water resources to the wellhead, then focuses on well design and construction characteristics related to protected ground water resources reported by well operators.

4.3.1. Surface Locations of Drinking Water Resources

Figure 15 shows the estimated number of oil and gas production wells hydraulically fractured by the nine service companies that had one or more of the specified drinking water resources within 0.5 miles of the wellhead.

[64] Figure 14 used 10,738 bond indices calculated from standard acoustic cement bond logs run in 203 study wells. Up to 14 percent of the 10,738 calculated bond indices may have been affected. The statistical weights among the study wells contributing data to Figure 14 ranged from 10 to 148. If all of the affected bond indices were evenly distributed across all of the calculated bond indices and had a statistical weight of 10, approximately 2 percent of the 822,299 points used to calculate the percentiles in Figure 14 would be affected. If all of the affected bond indices were evenly distributed across all of the calculated bond indices and had a statistical weight of 148, approximately 27 percent of the 822,299 points used to calculate the percentiles in Figure 14 would be affected.

[65] The use of different cements in the same well may affect the amplitude signal. The use of different cements could not be accounted for, because the depth at which the cement type changed was unclear in many wells.

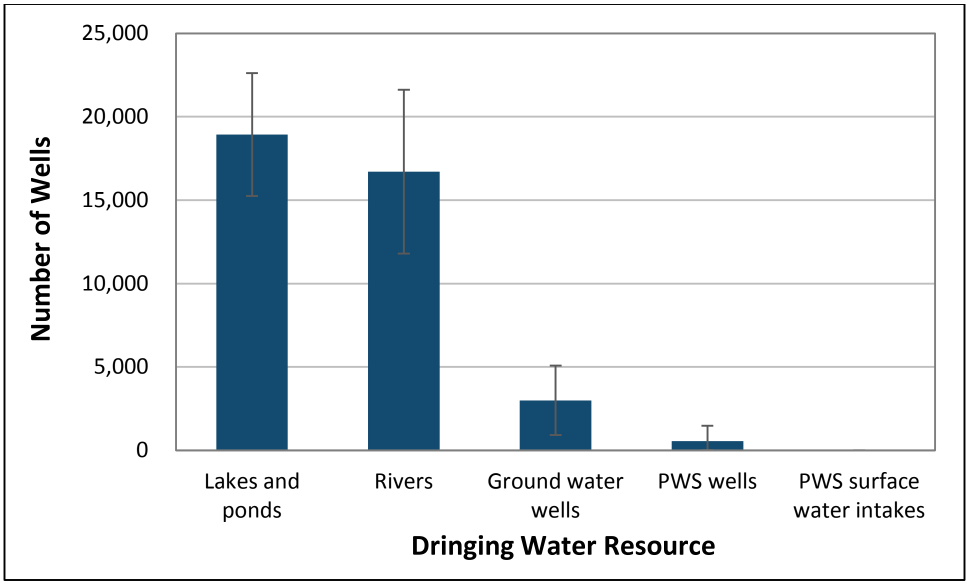

Figure 15. Drinking water resources within 0.5 miles of oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Drinking water resources were defined as any body of water, ground or surface, that currently serves or in the future could serve as a source of drinking water for public or private water supplies. This report does not identify whether surface water resources currently serve as drinking water resources. The presence or absence of current drinking water resources was determined using locations of public water system wells and surface water intakes. No production wells were estimated to have a surface water intake for a public water supply (PWS) within 0.5 miles of the wellhead. Private ground water wells were identified through information provided by well operators. The number of hydraulically fractured production wells within 0.5 miles of a private ground water well is expected to represent a lower-bound estimate. Error bars display 95 percent confidence intervals.

An estimated 18,900 wells (15,200-22,600) were within 0.5 miles of a surface water resource (i.e., lake, pond, or river). Fewer production wells were estimated to be within 0.5 miles of either a private ground water well (3,000; 900-5,100) or a public water supply well (600; 10-1,500). The number of hydraulically fractured production wells within 0.5 miles of a private ground water well is likely a lower-bound estimate.[66] An estimated 17,100 production wells (12,400-21,900) had more than one water feature within the 0.5 mile radius, while 4,100 production wells (600-7,600) had no water feature identified within 0.5 miles of the wellhead. No study wells were found to be within 0.5 miles of a surface water intake for a public water supply system.

4.3.2. Protected Ground Water Resources

Depths of protected ground water resources were provided by well operators for nearly all of the study wells. As described in Section 3.4.3, operators used different data sources to report depths of protected ground water resources. Because the analyses presented below compare well construction characteristics to the depths provided by well operators, the use of different data sources may affect the results of the analyses. Therefore, it is important to understand how the data

[66] Nationwide data on the locations of private drinking water wells are not available. Well operators were asked for results from water quality analyses of nearby surface or ground water (Appendix B). Private ground water wells were identified only if sample results were provided. It is likely that additional private ground water wells were present, but not sampled.

sources used by the operators to report depths to protected ground water resources are represented throughout the sampled population of oil and gas production wells hydraulically fractured by the nine service companies. Table 5 shows the number of production wells represented by each type of data source and shows that, for the majority of wells, protected ground water resources were identified by the well operators from state or federal authorization documents (e.g., permits to drill or permit applications).

Table 5. Information submitted by operators to report the depths of protected ground water resources at each study well location.

Data Sources Reported by Operators	Agency-based*	Base of Protected Ground Water Resource Depth	Number of Wells	95 Percent Confidence Interval
Well authorization documentation	Yes	Yes	11,700	10,800-12,700
		No†	1,500	1,300-1,700
Aquifer maps	Yes	Yes	4,000	3,400-4,500
Data from offset production wells	No	Yes	2,300	10-6,200
Operator experience§	No	Yes	1,900	10-6,100
Open hole log interpretation	No	Yes	1,100	10-3,700
General agency requirement	Yes	Yes	500	400-500
Well authorization without documentation‡	Yes	Indeterminate	100	60-200
Online database	Yes	Yes	90	50-100

***** "Agency" refers to the state oil and gas agency or the U.S. Bureau of Land Management.

† Ground water depths based on the depth of a nearby water well were not considered to represent the base of the aquifer, since deeper water wells may be drilled nearby at a later date.

§ No exact ground water depth value was provided. Operators stated that protected ground water is located at some depth less than the value provided (e.g., less than 200 feet).

‡ No exact ground water depth value was provided. Operators inferred that protected ground water depth is located at a depth shallower than surface casing because of state agency approval.

Operators reported either the depth to the base of the protected ground water resource (i.e., "base identified") or the depth to some portion of the protected ground water resource (i.e., "base not identified"). Table 5 shows that the base of the protected ground water resources was identified by the well operator for most wells (20,500 wells; 16,300-24,600). The distinction between "base identified" and "base not identified" affects analyses that compared well construction characteristics to operator-reported depths to protected ground water resources. The depth to the base of the protected ground water resource is unknown for "base not identified" wells. In these cases, it is likely that the base of the protected ground water resource is deeper than the depth reported by the well operators.[67] Results presented for these wells may be different if the depth of the base of the protected water resources was used instead of the depth provided by the well operator. Therefore, results are shown for wells in which the base of the protected ground water

[67] Ground water depths based on the depth of a nearby water well were not considered to represent the base of the aquifer, since deeper water wells may be drilled nearby at a later date.

resource for the study well was identified (dark blue bars in Figures 16, 17, and 18) and also for wells in which the base of the protected ground water resource for the study well was not identified (light blue bars). Well files for a small number of study wells had insufficient data to identify the base or depth of protected ground water resources. These wells represent an estimated 100 wells (60-200) in the sampled population of hydraulically fractured oil and gas production wells and were excluded from analyses that used depths of operator-reported protected ground water resources.

Operator-reported depths to protected ground water resources ranged from just below ground surface to 8,000 feet deep. The distribution of reported depths to ground water resources is shown in Figure 16. An estimated 21,400 wells (18,900-24,000) passed through operator-reported protected ground water resources that were less than 2,000 feet deep.

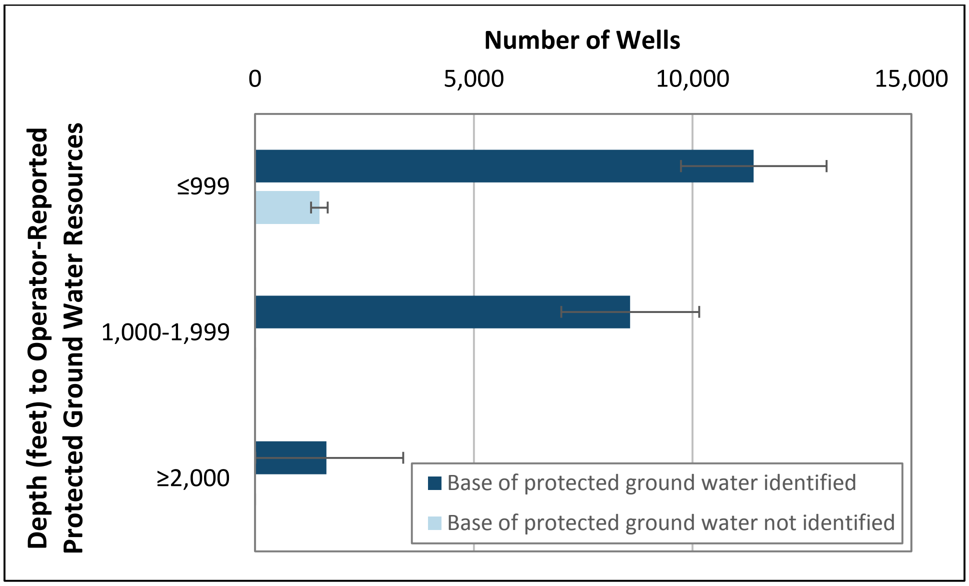

Figure 16. Depths of operator-reported protected ground water resources for oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Well counts are grouped according to whether or not the base of the operator-reported protected ground water resources was identified. Error bars display 95 percent confidence intervals.

Operator-Reported Protected Ground Water Resources Relative to Casing and Cement. As described in Section 2, surface casing generally serves as an anchor for blowout protection equipment and to seal off ground water resources. Measured surface casing depths were subtracted from operator-reported protected ground water resource depths to determine whether surface casing was installed deeper than protected ground water resources. The subtraction was done for individual wells, and the results were then extrapolated to the sampled population of oil and gas production wells; Figure 17 displays the results of this analysis.

Figure 17 shows that surface casing extended below the base of the operator-reported protected ground water for 12,600 wells (8,000-17,300). Most surface casings were fully cemented (Figure 12); in these cases, the operator-reported protected ground water resources located at depths shallower than the bottom of the surface casing are covered by cement in the annular space. If the

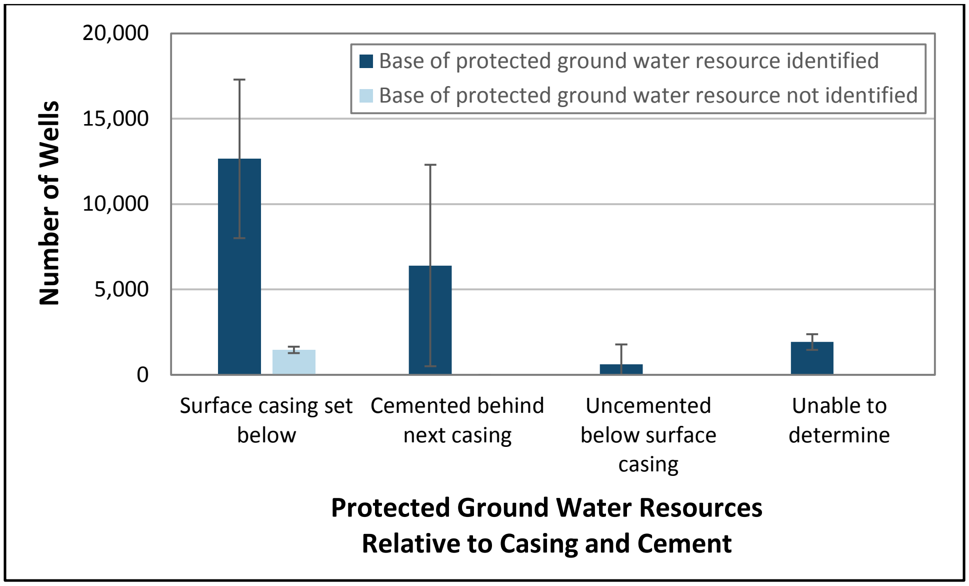

Figure 17. Comparison of casing and cement to operator-reported protected ground water resources among oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Well counts are grouped according to whether or not the base of the operator-reported protected ground water resource was identified. For some wells, there was either ambiguity in the depth of the base of the protected ground water resource or in the top of the protected ground water resource. These wells are categorized as "unable to determine." Error bars display 95 percent confidence intervals.

surface casing was partially cemented, the operator-reported protected ground water resource may or may not be covered by cement in the annular space. An additional 6,400 wells (500-12,300) had operator-reported protected ground water resources located deeper than the bottom of the surface casing that were covered by the next cemented casing string (either fully cemented intermediate or fully cemented production casing).

The remaining wells may have had some part of the operator-reported protected ground water resources not covered by cement in the annular space (Figure 17). In these cases, the bottom of the surface casing was shallower than the operator-reported depth to the base of the protected ground water resource and the next casing string was either partially cemented or uncemented. These wells were further examined to determine whether any portion of the protected ground water resource was uncemented based on the operator-reported depth to the base of the protected ground water resource and the location of the cement top behind the next deeper casing. There were sufficient data in the well files to determine that a portion of the operator-reported protected ground water resource was uncemented below the surface casing in an estimated 600 wells (10-1,800). The well files representing the remaining 1,900 wells (1,500-2,400) 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 of the operator-reported protected ground water resource[68] or in the top of the protected ground water resource.

Figure 17 also shows that all wells in which the operator-provided protected ground water resource is "base not identified" had surface casing that extended below the depth used to identify the location of the protected ground water resource (1,500 wells; 1,300-1,700). Since the base of the protected ground water resource is not known for these wells, it could not be determined if the surface casing or another cemented string of casing covers the entire protected ground water resource in the annular space.

Estimated Separation Distance. The separation distance was estimated by subtracting the depth of the operator-reported protected ground water resources from the measured depth of the point of shallowest hydraulic fracturing (Figure 18). In nearly all cases, measured depths of the point of shallowest hydraulic fracturing were deeper than operator-reported depths to protected ground water resources, as shown in Figure 18. In an estimated 90 wells (10-300), the measured depth of the point of shallowest hydraulic fracturing was shallower than the base of the operator-reported protected ground water resource.[69]

Estimated separation distances shown in Figure 18 are not always equal to the true vertical separation distances, which is defined as the vertical distance from the point of shallowest hydraulic fracturing to the depth of the operator-reported protected ground water resources. In perfectly vertical wells, the estimated separation distance is the true vertical separation. True vertical separation distances for deviated and horizontal wells are expected to be smaller than the estimated separation distances shown in Figure 18. For wells in which the operator-reported protected ground water resource is "base not identified," the estimated separation distance between the point of shallowest hydraulic fracturing and the actual base of the protected ground water resource is likely to be smaller than what is shown in Figure 18.

5. Potential Subsurface Fluid Movement Pathways

The results presented in Section 4 indicate a range of well design and construction characteristics for oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Some well design and construction characteristics can act as barriers (e.g., casing and cement) that block pathways for subsurface fluid movement between ground water resources and other formations. Subsurface fluid movement depends on many factors, including the existence of a pathway, the presence of a fluid, and a driving force. Pathways, in this report, are defined as any opening along which fluids can flow and can exist regardless of whether fluids are flowing. Fluids can include gases or liquids naturally present in the subsurface (e.g., brine, methane, or other hydrocarbons) or gases or liquids that are introduced into the subsurface during well construction and completion (e.g., hydraulic fracturing fluid). Naturally

[68] In these cases, operators indicated that the base of the protected ground water resource was less than or equal to a given depth. The maximum value provided was used in this analysis.

[69] In these cases, the top of the protected ground water resource was also identified and was shallower than the measured depth of the point of shallowest hydraulic fracturing.

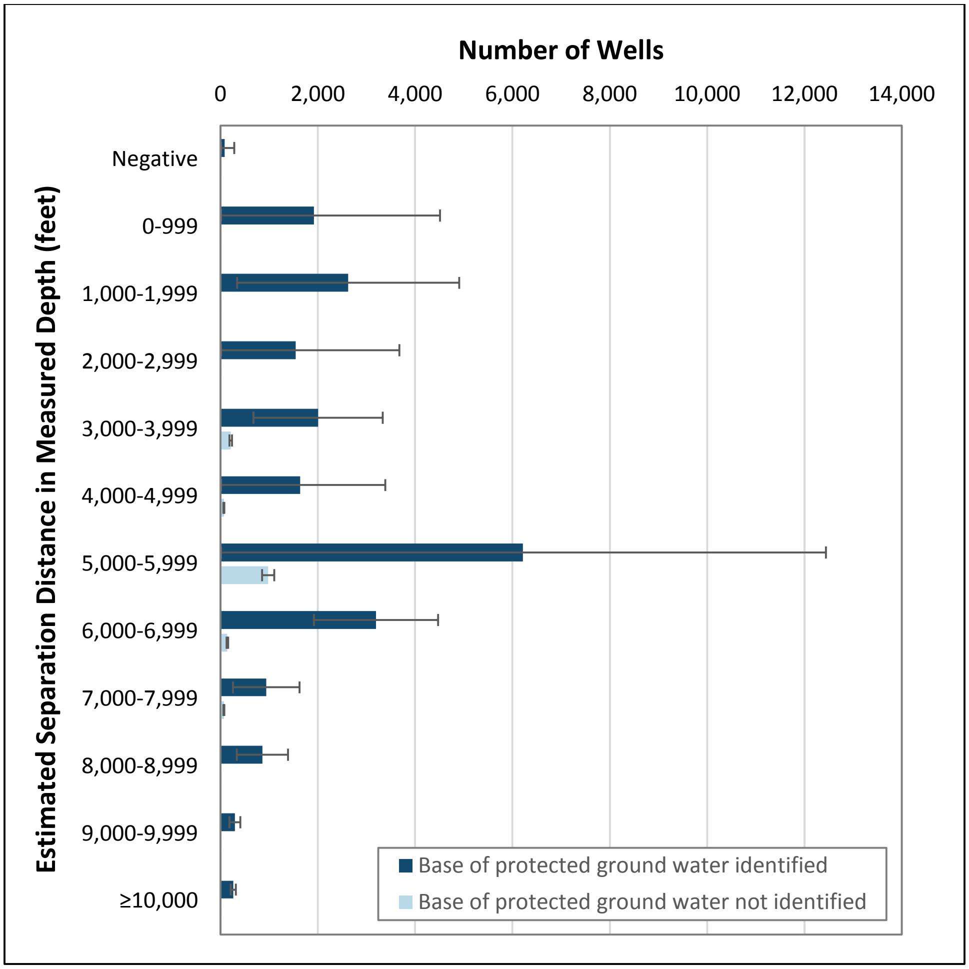

Figure 18. Estimated separation distance between the point of shallowest hydraulic fracturing and the depth of operator-reported protected ground water resources for oil and gas production wells hydraulically fractured by nine service companies between approximately September 2009 and September 2010. Well counts are grouped according to whether or not the base of the operator-reported protected ground water resources was identified. The “negative” category indicates the number of wells in which the point of shallowest hydraulic fracturing is at a measured depth that is less than the operator-reported depth of protected water resources. Error bars display 95 percent confidence intervals.

present fluids can originate from the targeted geologic formation or from intermediate water- and/or hydrocarbon-bearing zones (Council of Canadian Academies, 2014). Subsurface fluid movement can occur due to gravity, a pressure differential, or gas buoyancy (Council of Canadian Academies, 2014; Flewelling and Sharma, 2014; Kissinger et al., 2013; Myers, 2012).

Impacts to drinking water resources may occur when fluids flow through a continuous pathway that extends from a source zone to a ground water resource. A continuous pathway could involve pathways along the well that are introduced during well construction, pathways through the overlying geology, or some combination of the two (Council of Canadian Academies, 2014; Kissinger et al., 2013; Myers, 2012; US EPA, 2012; Vengosh et al., 2014). The discussion below focuses only on the potential for well construction pathways to exist and does not address other potential pathways or the presence of a fluid or driving force.

Figure 19 illustrates two potential pathways related to well construction that connect a well to a ground water resource: (1) from the inside of the well to the outside (Pathway A in Figure 19) and (2) along the outside of the well (Pathway B in Figure 19). While Figure 19 illustrates potential pathways for fluid movement directly to ground water resources, subsurface fluid movement to ground water resources may occur via a combination of Pathways A and B. Although combinations of these pathways are possible, the discussions presented below focus on the presence or absence of Pathway A and Pathway B at any point along the well.

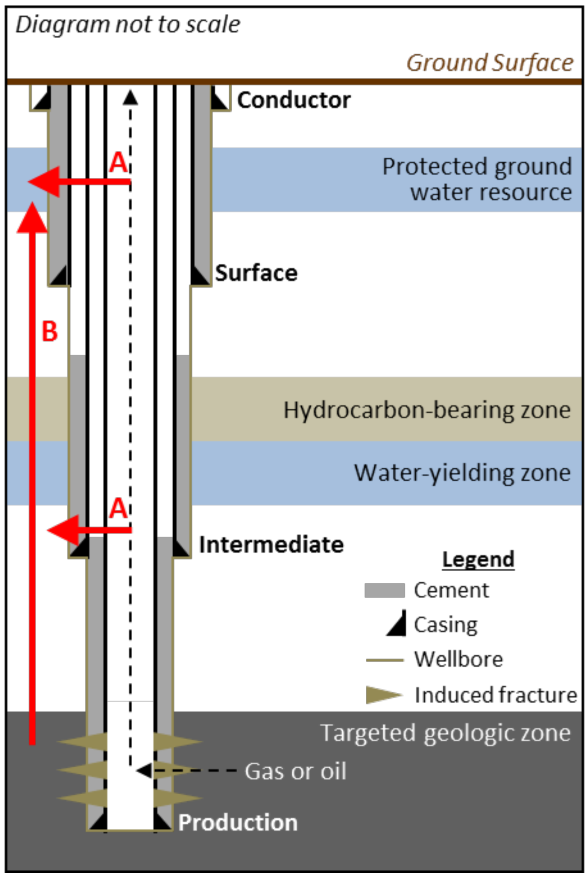

Figure 19. Potential well construction pathways for subsurface fluid movement. Pathway A illustrates fluid movement from the inside of the well to the outside. Pathway B illustrates fluid movement along the outside of the well. Fluid movement along these potential pathways is dependent on the existence of the pathway, the presence of a fluid, and a pressure differential.

5.1. Potential Pathway A: Inside to outside

Pathway A can occur at any point along the well. When Pathway A directly extends to a drinking water resource, there can be impacts to that resource. When Pathway A does not extend to a drinking water resource, and instead extends to a point below or above the drinking water resource, an additional pathway (e.g., Pathway B) is needed to connect Pathway A to a drinking water resource.

The existence of Pathway A depends, in part, upon the presence or absence of casing and cement. Casings and cement sheaths act as barriers to fluid movement by interrupting Pathway A (Davies et al., 2014; Gray et al., 2009; GWPC, 2009; King and King, 2013). Wells are often constructed with multiple barriers to minimize or prevent well integrity failures (Davies et al., 2014; King and King, 2013).[70] This section summarizes the number of casings (Figure 20) and cement sheaths (Figure 21) between the inside of a well and the wellbore at different measured depths. Conductor casing or other shallow, often uncemented casings were excluded from these analyses.

Figure 20 shows the estimated number of wells having zero, one, two, or three casing strings separating the inside of the well from the wellbore at different measured depths.[71] In general, the number of casing strings decreased as the measured depth increased, which was expected given the purpose of each casing string, as described in Section 2. At measured depths reflective of operator-reported ground water resources (generally <2,000 feet, as shown in Figure 16), most wells had either one or two casing strings. At very shallow depths (<500 feet), there was a relatively large proportion of wells that had three casing strings. A smaller number of wells (<1,500) had no casing (open hole; Figure 20b) between 700 and 4,200 feet along the length of the well. By design, these wells had no casing or cement barriers between the inside of the well and the surrounding environment along the open hole completion section (Figure 20b).

Figure 21 shows the estimated number of wells having zero, one, two, or three cement sheaths separating the inside of a well from the wellbore at different measured depths. Figures 20 and 21 show that, at many measured depths below the surface, there was typically one more casing string present than the number of cement sheaths, which suggests that the casing strings counted in Figure 21 were often not cemented to the surface. Most wells, at any given measured depth, had one cement sheath between the inside of the well and the wellbore. At measured depths reflective of operator-reported ground water resources (generally <2,000 feet), most wells had one cement sheath. Between 4,900 and 9,100 wells had zero cement sheaths between 1,000 and 4,000 feet of measured depth. At these depths, there may be an uncemented interval behind casing or an open hole completion (panel b in Figure 21). A small number of wells (<100) had three cement sheaths at shallow measured depths (<400 feet).

Figures 20 and 21 depict a range in the number of casing and cement barriers, from zero in open hole completions to six when surface, intermediate, and production casing were each cemented to the surface. The most common number of casing and cement barriers, at any point along a well, was either two (one casing string and one cement sheath) or three (two casing strings and one cement sheath). Under this scenario, Pathway A would have to extend through at least one casing and one cement sheath to allow fluid to move from the inside of the well to the wellbore. A pathway through

[70] A barrier failure occurs when a single element within a well fails, but there is no evidence of fluid migration to the surrounding environment or surface. A well integrity failure occurs when no barriers are left to prevent fluid leaking into the environment (King and King, 2013).

[71] The analyses presented here do not consider well components that can serve as barriers, but are either temporary or easily removed. Temporary well components that can serve as additional barriers may be installed during hydraulic fracturing, such as a frac string, or after hydraulic fracturing, such as tubing set on a retrievable packer.

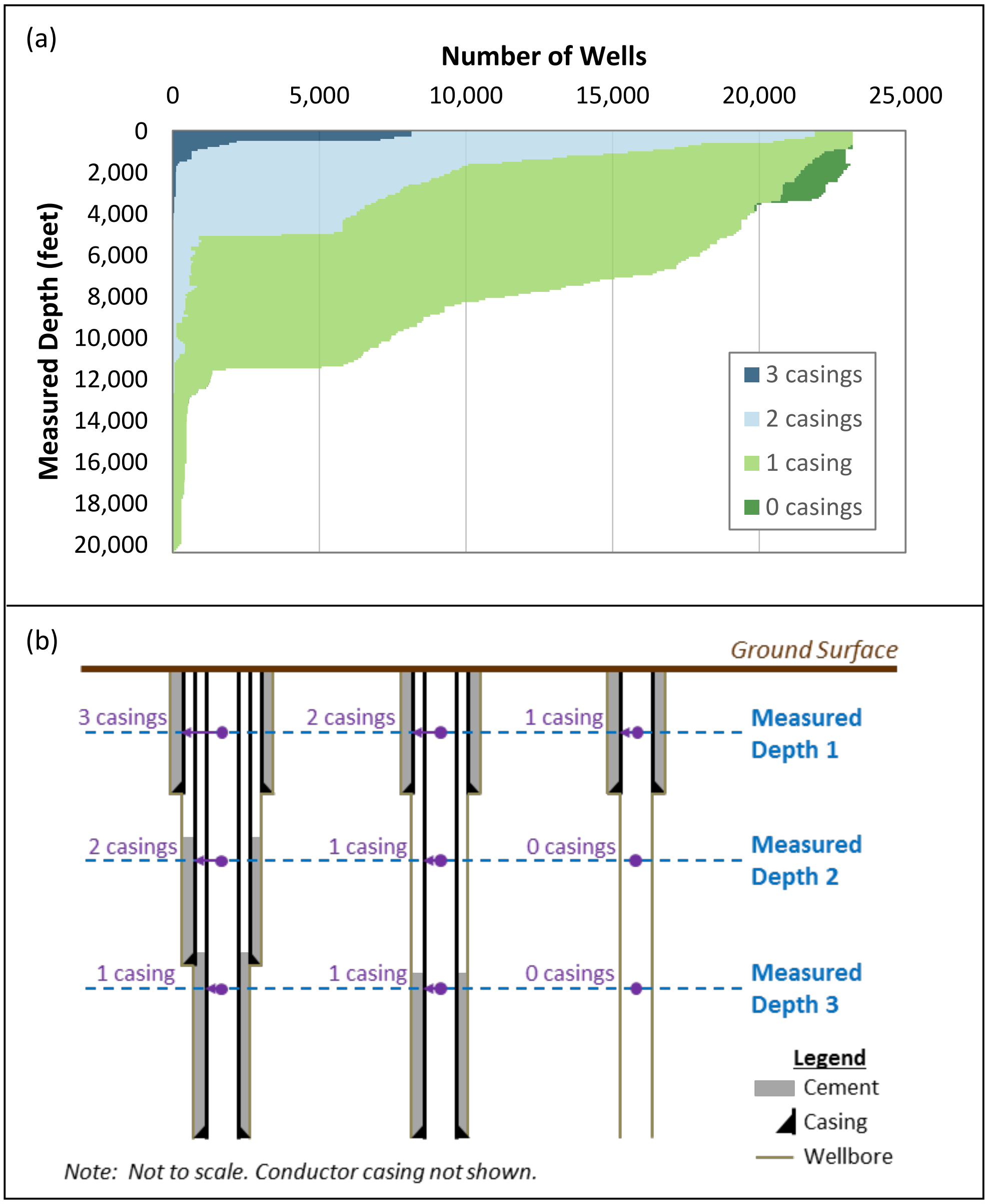

Figure 20. (a) Concentric casings between the inside of the well and the wellbore at different measured depths along the well. (b) Illustrative examples of wells with different numbers of concentric casings at example Measured Depths 1, 2, and 3 along the well.

casing may occur if casing collars leak or if the casing collapses, ruptures, or corrodes (King and King, 2013; Smith, 1976; US EPA, 2012). A pathway through cement may occur if channels form in the cement during the cementing process, if the cement does not withstand stresses applied during drilling or completion activities, or if the cement degrades over time (Council of Canadian Academies, 2014; McDaniel et al., 2014). A pathway through casing and cement occurs when casing and cement are perforated for hydraulic fracturing. Perforations used for hydraulic fracturing were placed deeper than the base of operator-reported protected ground water resources in all but an estimated 90 wells (10-300).

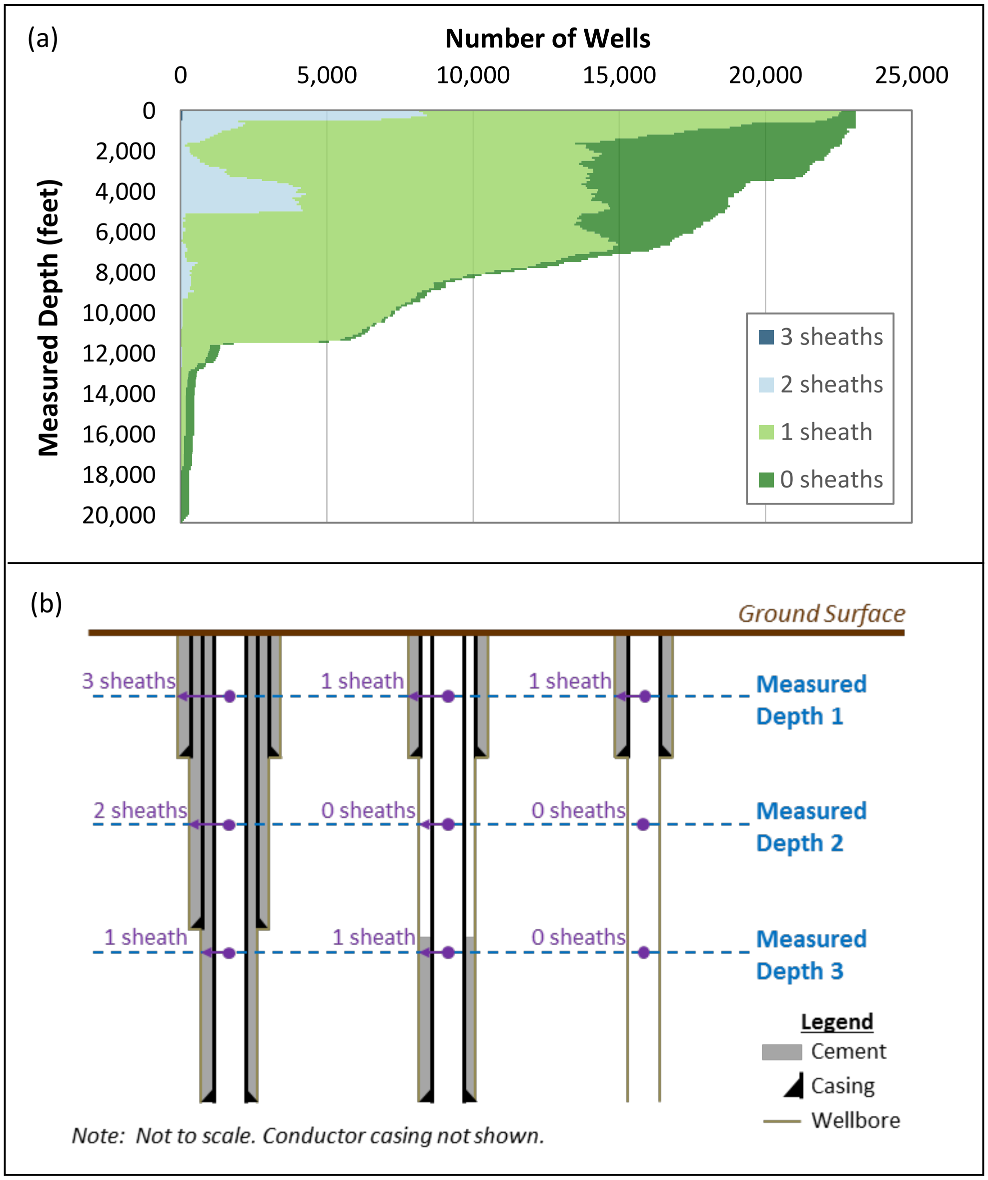

Figure 21. (a) Cement sheaths between the inside of the well and the wellbore at different measured depths along the well. An estimated 2,200 wells (1,000-3,400) contain cement whose depth interval is uncertain and are not included in panel a. (b) Illustrative examples of wells with different numbers of cement sheaths at Measured Depths 1, 2, and 3 along the well.

5.2. Potential Pathway B: Along the outside of the well

Pathway B focuses on the potential for fluids to migrate along any portion of the outside of a well. When Pathway B directly connects to a drinking water resource, there can be impacts to that resource. When Pathway B does not directly connect to a drinking water resource, an additional pathway is needed to connect Pathway B to a drinking water resource.

The existence of Pathway B depends on the presence or absence of cement and the quality of the cement present (Brufatto et al., 2003; GWPC, 2014; Holt and Lahoti, 2012). Cemented casings can act as barriers to subsurface fluid movement by interrupting Pathway B. To explore the role of cemented casings in preventing subsurface fluid movement, this section first summarizes the presence and absence of cement along the outside of a well, and then briefly addresses the quality of any cement present.

Presence or Absence of Cement. An estimated 6,800 wells (1,600-11,900) were fully cemented along the outside of the well, from the bottom of the well to the ground surface. In these wells, all casing strings were continuously cemented either to the surface or into the next overlying casing. An estimated 15,300 wells (10,500-20,100) had one or more uncemented intervals along the outside of the well, from the bottom of the well to the ground surface. Figure 12 indicates that uncemented intervals were common for production casing, and to a lesser extent, intermediate casing.

Several studies that involved monitoring of uncemented annuli indicate that uncemented intervals can be pathways for gas and liquid movement (Brufatto et al., 2003; Ohio Department of Natural Resources, 2008; Watson and Bachu, 2009).[72] After reviewing 142 wells in Alberta, Canada, Watson and Bachu (2009) determined that the factor most strongly correlated with annular gas flow is the length of the uncemented annulus. Additionally, Harrison (1985) demonstrated how a well with an uncemented annulus between its casing and formation wall can unintentionally contribute contaminants to subsurface drinking water supplies from intermediate depths and may do so despite wellhead monitoring meant to detect it. The Ground Water Protection Council (2014) also identified the potential movement of fluids along the casing/formation annulus as a risk to ground water. They noted that “the most effective means of protecting ground water from upward migration in the annulus is the proper cementation of well casing across vertically impermeable zones and ground water zones.”

Many sources recommend that cement be placed across zones containing corrosive fluids, water in need of protection, or hydrocarbons (Nelson and Guillot, 2006; Ross and King, 2007; Smith, 1976). Participants at a 2013 EPA technical workshop on well construction and operation noted that full cementing of annular spaces can enhance barrier functioning, but that cement placed to the surface eliminates an operator’s ability to monitor annular pressure for insights into well conditions during operations (US EPA, 2013a). If annulus monitoring or testing detects fluid movement that causes concern, a common response is to place cement in the uncemented portion of the well, if possible (Nelson and Guillot, 2006; Smith, 1976; US EPA, 2013a).

The presence or absence of cemented casing strings between the targeted geologic formation and protected ground water resources affects whether a direct pathway along the outside of the well exists for fluids to move from the targeted geologic formation to protected ground water resources. Figure 22 shows the estimated number of wells having zero, one, two, three, or four cemented casings, independent of the quality of the cement, between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resource. The number of cemented casings is plotted for different estimated separation distances in measured depths, as illustrated in panel b.

[72] In this report, an uncemented interval is defined as a segment of annular space along the outside of the well (between the casing and the wellbore wall) that has no cement, while an uncemented annulus is defined as an uncemented interval that reaches the surface.

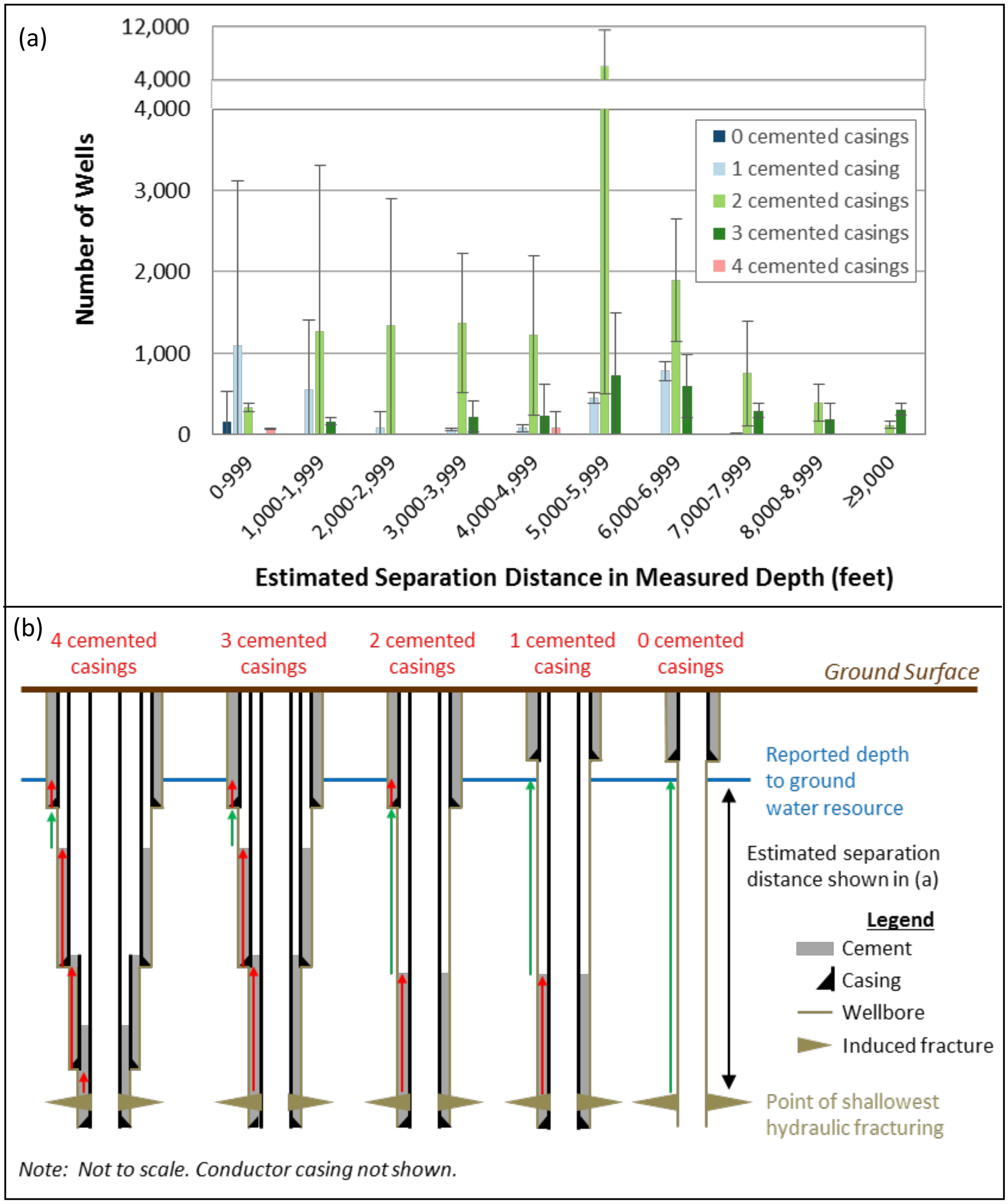

Figure 22. (a) Cemented casing strings along the outside of the well between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resources. All operator-reported depths to protected ground water resources were used, regardless of whether the depth was reported as the base of the ground water resource. Wells in which the point of shallowest hydraulic fracturing was shallower than the base of the operator-reported protected ground water resource are excluded from panel a. An estimated 2,200 wells (1,000-3,400) contain cement whose depth interval is uncertain; these wells are also excluded from panel a. Error bars display 95 percent confidence intervals. (b) Illustrative examples of wells with different cemented casing strings between the point of shallowest hydraulic fracturing and operator-reported protected ground water resources. The red arrows indicate cemented casing, and the green arrows show uncemented intervals.

Figure 22 shows that the number of cemented casings between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resource ranged from zero (open hole) to four, with more than half of the wells having two cemented casings. The number of cemented casings generally increased as the estimated separation distance increased. At estimated separation distances of less than 1,000 feet, wells had either zero cemented casings (open hole) or one cemented casing. At the most commonly identified estimated separation distance (5,000-5,999 feet), wells had between one and three cemented casings. At estimated separation distances greater than 9,000 feet, wells had two or three cemented casings between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resource.

As illustrated in Figure 22b, multiple cemented casings, which were commonly reported in this study, did not preclude the presence of uncemented intervals, which have been shown to serve as pathways for fluid movement (see above). Figure 22 also shows that more than half of the wells in this study had two or more cemented casings that can interrupt Pathway B between the point of shallowest hydraulic fracturing and the operator-reported protected ground water resource. This indicates that there were often two or more barriers to potential subsurface fluid movement along the outside of a well from the targeted geologic formation to protected ground water resources.

Quality of Cement. Cement coverage and bonding in the annulus between the outer casing and the wellbore also influences Pathway B in Figure 19. Complete circumferential cement coverage and bonding isolates zones that could otherwise communicate via the outside of a well (Brufatto et al., 2003; Holt and Lahoti, 2012; Smolen, 1996). Most well files used in this study contained a standard acoustic cement bond log, which can be used to evaluate both the extent of the cement placed along the casing and the cement bond between the cement, casing, and wellbore. Figure 14 shows that calculated cement bond indices were generally greater near the point of shallowest hydraulic fracturing (the 50th percentile bond index was 0.7) than at shallower measured depths (the 50th percentile bond index was 0.4 at 5,000 feet away from the shallowest point of hydraulic fracturing).

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; Flournoy and Feaster, 1963; Smolen, 1996). In addition, they cannot always discriminate between full circumferential cement coverage by weaker cement and lack of circumferential coverage by stronger cement (King and King, 2013; Smolen, 1996).[73] 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 inch diameter casing with a bond index of 0.80 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 0.80 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. 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. Because of the ambiguity associated with using cement bond logs to determine zonal isolation, the results of the cement bond log analysis conducted for this report should not be used to determine the extent to which wells hydraulically fractured by the nine service companies had zonal isolation.

[73] "Weaker cement" refers to cement that has lower attenuation properties. "Stronger cement" refers to cement that has higher attenuation properties.

The trends observed in Figure 14 suggest that the quality of the cement bond in the wells, as indicated from calculated cement bond indices, was likely to be better near the point of shallowest hydraulic fracturing.

6. Representativeness Analysis

The results presented in Sections 4 and 5 are representative of onshore oil and gas production wells that were hydraulically fractured by nine service companies in the continental United States between approximately September 2009 and September 2010. Wells fractured by the nine service companies were predominantly vertical wells drilled after 2000 (Figure 4). Starting in about 2005, however, horizontal drilling technologies began to be widely used to access unconventional geologic formations for oil and gas production (Baker Hughes, 2014; GWPC and ALL Consulting, 2009).[74] The reported increase in horizontal well completions raises two questions for this study:

- Are the wells hydraulically fractured by nine service companies representative of all onshore oil and gas production wells hydraulically fractured in the continental United States over the timeframe examined in this study?
- Would the results presented in this report change significantly if more horizontal wells would have been sampled?

Since the information needed to compile a comprehensive list of hydraulically fractured oil and gas production wells in the United States is not generally available, the EPA used DrillingInfo (2012), a commercial database compiled from data maintained by individual state oil and gas agencies, to estimate the national number of horizontal and vertical wells hydraulically fractured in 2009 and 2010.[75] Well estimates from DrillingInfo were based on the assumptions that all horizontal oil and/or gas wells were hydraulically fractured in the year they started production and that all oil and/or gas wells within a shale, coalbed, or low permeability formation,[76] regardless of well orientation, were also hydraulically fractured in the year they started production.[77]

Because hydraulically fractured well estimates from DrillingInfo are limited by the year of initial production (i.e., hydraulic fracturing is assumed to have occurred in the same year as the initial production), well estimates from DrillingInfo were compared to well estimates developed from the subset of study wells that were hydraulically fractured within a year of being drilled. Since all wells in this study were hydraulically fractured between approximately September 2009 and September 2010, the subset of wells used for this comparison included 179 study wells that were reported by the well operators to have been drilled and hydraulically fractured within one year of the last date

[74] In this instance, "unconventional" geologic formations refer to formations in which it is uneconomical to produce oil and gas using traditional drilling and completion technologies. Examples include shale and tight gas formations.

[75] DrillingInfo does not track whether a well has been hydraulically fractured.

[76] Identification of shale, coalbed, and low permeability formations is based on a crosswalk of information available in DrillingInfo with expert knowledge at the US Energy Information Administration (US EIA, 2012).

[77] This is similar methodology to that used by the EPA for its *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (US EPA, 2014b).

in the study's timeframe (September 30, 2010). To compare well estimates from the study wells to estimates derived from DrillingInfo, well orientations for each study well were assigned using the designations provided in DrillingInfo (i.e., vertical, horizontal, directional, or unknown).[78] Figure 23 shows the results of this comparison.

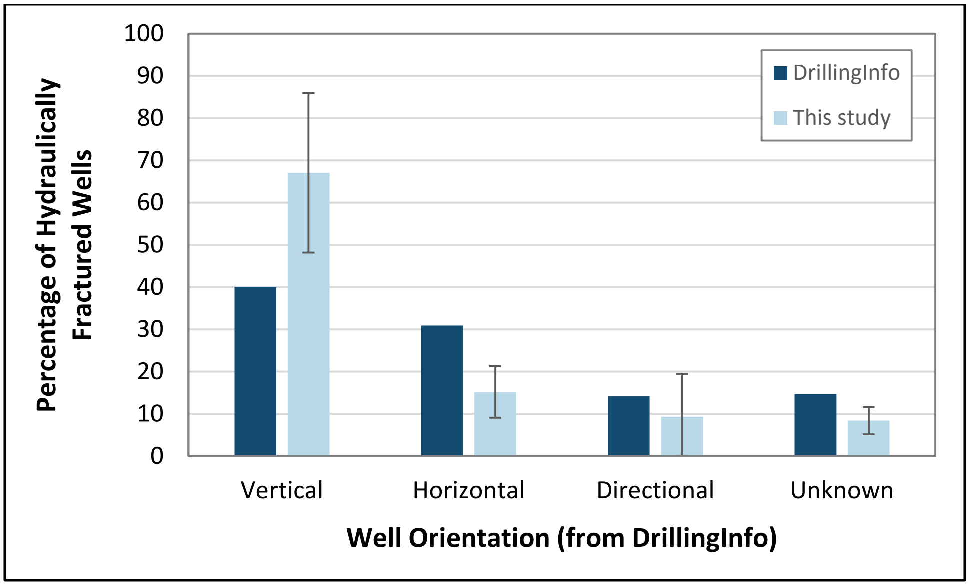

Figure 23. Comparison of well estimates developed from DrillingInfo to well estimates developed from well files used in this study. Data obtained by the EPA from DrillingInfo were used to develop estimates of the national number oil and gas production wells drilled and hydraulically fractured in the continental United States in 2009 and 2010. Well files from this study were used to estimate the number of oil and gas production wells drilled between approximately September 2009 and September 2010 and hydraulically fractured by nine service companies within the same timeframe.

Using the well orientations designated in DrillingInfo and applied to the study population, 67 percent (48-86 percent) of wells drilled in 2009 and 2010 and hydraulically fractured by the nine service companies were estimated to be vertical wells, and 15 percent (9-21 percent) were estimated to be horizontal. The number of oil and gas production wells hydraulically fractured in 2009 and 2010 estimated from DrillingInfo also shows that more vertical wells were hydraulically fractured (40 percent) in 2009 and 2010 than horizontal wells (31 percent). Differences in the percentages of horizontal and vertical wells may arise from one or both of the following factors: (1) incorrect or missing information in DrillingInfo, as described below, or (2) the newly drilled wells reported by the nine hydraulic fracturing service companies are not representative of newly drilled and hydraulically fractured wells reported in DrillingInfo.

The well estimates from DrillingInfo in Figure 23 were developed using the assumptions outlined above and then corrected after comparing well-specific information from the well files to data

[78] Definitions for different well orientations in DrillingInfo were not specified. When matching 171 study wells to data in DrillingInfo, 98 percent of horizontal wells, as defined in this study, were also designated as horizontal in DrillingInfo. Wells classified as vertical in this study were mostly designated as vertical in DrillingInfo (78 percent of vertical wells, as defined in this study); 17 percent of vertical wells, as defined in this study, were categorized as unknown in DrillingInfo. Wells classified as deviated in this study were designated as either directional (43 percent of the deviated wells), vertical (43 percent), or unknown (14 percent).

obtained by the EPA from DrillingInfo. The well-specific comparisons suggested that data obtained by the EPA from DrillingInfo may not have been complete and that the assumptions used to identify hydraulically fractured wells in DrillingInfo underestimated the national number of hydraulically fractured oil and gas production wells. As stated above, 179 of the study wells were used to assess the national representativeness of wells surveyed in this study. Most (171) of the 179 study wells were matched with well-specific entries in DrillingInfo, indicating that 4 percent of oil and gas production wells may not be found in DrillingInfo or may not be easily identifiable in DrillingInfo.[79] Eighty-one percent of the 171 matched wells were correctly identified as hydraulically fractured using the assumptions described above. The other 19 percent of wells were found in DrillingInfo, but not identified by the EPA as hydraulically fractured using the assumptions. All horizontal wells, as defined by DrillingInfo, were found to be correctly identified as hydraulically fractured, but counts of hydraulically fractured vertical and directional wells were underestimated by 23 percent and 129 percent, respectively. Given the limitations of the data in DrillingInfo, it was not possible to use DrillingInfo to determine whether the oil and gas production wells hydraulically fractured by the nine service companies between approximately September 2009 and September 2010 were representative of all oil and gas production wells hydraulically fractured during that timeframe.

Well estimates derived from DrillingInfo, as well as other data, suggest that the proportion of horizontal well completions has increased since 2005 (Baker Hughes, 2014; DrillingInfo, 2012). Given this apparent shift in the prevalence of drilling orientation, the data from this study were used to determine whether the results presented in Sections 4 and 5 are sensitive to different well orientations. To do this, the statistical weights associated with each study well (Section 3.5) were skewed such that the summed statistical weights of horizontal wells represented 90 percent of the 23,200 (21,400-25,000) oil and gas production wells estimated to have been hydraulically fractured by nine service companies. The remaining 10 percent of the surveyed population was represented by vertical and deviated study wells. Adjusting the statistical weights such that 90 percent of the surveyed population is horizontal overestimates the proportion of hydraulically fractured oil and gas production wells that are horizontal and should not be considered to produce true survey estimates. However, it allows the identification of well design and construction characteristics that may be different for horizontal well completions.

When 90 percent of the wells fractured by the nine service companies were assumed to be horizontal, the majority of hydraulically fractured lithologies were shale and most of the wells were less than a year old. Under this scenario, measured depths to the point of shallowest hydraulic fracturing were generally deeper (>4,000 feet) and operator-reported depths to protected ground water resources were generally shallower (<1,000 feet), when compared to Figures 8 and 16, respectively. Consequently, the estimated separation distance between the point of shallowest hydraulic fracturing and operator-reported protected ground water resources was generally more than 3,000 feet, as measured along the wellbore. Additionally, the estimated number of wells in which the point of shallowest hydraulic fracturing was shallower than the base of the operator-reported protected ground water resources decreased.

[79] This may be because not all DrillingInfo records contained usable API numbers. Some entries in the API number field had extra digits, while others did not appear to be API numbers.

Cemented surface casing covered operator-reported protected ground water resources in nearly all wells, when 90 percent of the wells fractured by nine service companies were assumed to be horizontal. The number of wells having some portion of the operator-reported protected ground water resource uncemented decreased, when compared to Figure 17. Furthermore, under this scenario, the number of intermediate casings that were partially cemented was estimated to increase, and the number of production casings that were set on formation packers with no cement was also estimated to increase. The majority of partially cemented casings under this scenario were estimated to have more than 50 percent of the evaluated casing length (i.e., from the bottom of the casing to next overlying casing or ground surface, if surface casing) cemented, which was similar to the trend presented in Figure 13. However, when 90 percent of the wells fractured by the nine service companies were assumed to be horizontal, more partially cemented production casings were estimated to have between 50 and 74 percent of the evaluated casing length cemented than were estimated to have more than 75 percent of the evaluated casing length cemented.

Under the scenario in which 90 percent of the wells in the sampled population were horizontal, nearly 80 percent of the wells were drilled within one year of being hydraulically fractured and almost 100 percent were drilled within 10 years. This shows that the newer wells in the sampled population are predominantly horizontal, which indicates that the service company well list captured the increase in the use of horizontal drilling technologies that began in approximately 2005 (Baker Hughes, 2014; GWPC and ALL Consulting, 2009).

As previously stated, adjusting the statistical weights such that 90 percent of the wells in the surveyed population were horizontal overestimated the proportion of hydraulically fractured oil and gas production wells that were horizontal. Additionally, the horizontal study wells used in this sensitivity analysis were mostly located in two sedimentary basins. Results from the sensitivity analysis, therefore, heavily represent well design and construction characteristics in those two basins and may not reflect characteristics across the United States. Consequently, the results from the sensitivity analysis should not be interpreted to represent horizontal oil and gas production wells in general. Rather, the results from the sensitivity analysis should only be used to identify well characteristics that may be different for horizontal well completions.

7. Study Limitations

The survey design and data collection process have implications for the interpretation of the results presented in Sections 4 and 5 of this report. As described in Section 3, the EPA used a stratified random sampling approach to select well files from nine oil and gas well operators based on well location and operator size. The study wells were selected from a list of well identifiers provided by nine hydraulic fracturing service companies and represent oil and gas production wells hydraulically fractured by those companies between approximately September 2009 and September 2010. As a result, the estimates of the frequency of occurrence of well design and construction characteristics presented in Sections 4 and 5 are statistically representative of the 23,200 (21,400-25,000) oil and gas production wells estimated to have been hydraulically fractured by the nine service companies in 2009 and 2010.

The estimates may not be statistically representative of all oil and gas production wells hydraulically fractured in the same time period. Comparisons between the service company well list and other data, however, suggest that observations made in this report are likely indicative of national well design and construction characteristics of oil and gas production wells hydraulically fractured in 2009 and 2010. As described in Section 3.1, the geographic distribution of well identifiers provided by the nine service companies resembled the geographic distribution of oil and gas production in the United States in 2009 and 2010. Additionally, an analysis of data obtained from DrillingInfo (Section 6) estimated that more vertical wells were hydraulically fractured in 2009 and 2010 than horizontal wells, which is consistent with data reported in this study (Figure 6c). Given the similarities in geographic distribution and well orientations, the results presented in this report are likely indicative of well design and construction characteristics of onshore oil and gas production wells that were hydraulically fractured in the United States during the timeframe examined in this study.

As mentioned in Section 6, the use of horizontal drilling technologies began to be widely used around 2005 and continued to be widely used in 2014 (Baker Hughes, 2014). The sensitivity analysis described in Section 6 identified well design and construction characteristics that may be different for horizontal well completions than non-horizontal well completions. Since wells hydraulically fractured by the nine service companies in this study were predominantly vertical well completions, it is possible that the specific well estimates presented in Sections 4 and 5 would be different if the survey had included more horizontal wells. The results of the sensitivity analysis should not be interpreted to represent horizontal oil and gas production wells in general. It is also possible that the estimates presented in this report may not apply to wells constructed and hydraulically fractured after 2010, if well design and construction practices changed after 2010.

Estimates of the frequency of occurrence of well design and construction characteristics are summarized in Section 4 and 5 at the national level. Given the survey design, it was not possible to display results at a smaller scale, such as targeted geologic formations. Estimates of the frequency of occurrence of well design and construction characteristics may be different for different regions of the country, because of differences in local geologic characteristics, state regulations, and company preferences, as described in Section 2. Despite variation in practices, the data in Sections 4 and 5 provide an overview of well design and construction characteristics of onshore oil and gas production wells hydraulically fractured in the United States in 2009 and 2010 and indicate that some characteristics were common.

Finally, the results presented in this report were generated from data provided by oil and gas well operators. No attempt was made to independently and systematically verify the data supplied by the operators, including depths to protected ground water resources. Consequently, the study results, which include comparisons of operator-reported protected ground water resources to well construction characteristics (Section 4.3.2), are of the same quality as the supplied data. Other sources, such as state oil and gas agencies, may identify different values for the data elements used in this study, which would affect the results presented in this report.

8. Conclusions

This study used data from a survey of oil and gas production wells to describe: (1) well design and construction characteristics of hydraulically fractured oil and gas production wells, (2) the relationship of well design and construction characteristics to drinking water resources, and (3) the number and relative location of well construction barriers that can block pathways for potential subsurface fluid movement. Results presented in this report are statistically representative of an estimated 23,200 (21,400-25,000) onshore oil and gas production wells in the continental United States that were hydraulically fractured in 2009 and 2010 by nine oil and gas service companies.

Oil and gas production wells hydraulically fractured by the nine service companies were predominately vertical wells drilled between 2000 and 2010, but also included other well orientations (i.e., horizontal and deviated) and wells drilled prior to 2000. The most common casing configuration, used in 55 (33-75) percent[80] of wells, was reported to be a surface and a production casing. Eighty-seven (68-96) percent[81] of wells had casing in the production zone that was cemented and perforated for hydraulic fracturing. Sixty-six (44-83) percent[82] of wells had one or more uncemented intervals along the outside of the well, from the bottom of the well to the ground surface, while 29 (13-53) percent[83] were fully cemented over the same interval.

Production wells were found to be located near surface and ground water resources that are currently used as sources of drinking water or may be used as sources for drinking water in the future. While proximity alone does not determine impacts, it is a factor that should be considered when assessing the potential for hydraulic fracturing to affect drinking water resources. Eighty-two (63-92) percent[84] of wells were located within 0.5 miles of a surface water resource (i.e., lake, pond, or river). Fewer production wells were within 0.5 miles of either a private ground water well [13 (7-23) percent[85]] or a public water supply well [2 (1-10) percent[86]]. Operator-reported depths to protected ground water resources ranged from just below ground surface to 8,000 feet deep. Ninety-two (81-97) percent[87] of wells passed through protected ground water resources less than 2,000 feet deep, as reported by well operators. Operator-reported protected ground water resources were estimated to be covered by cement in the annular space in most wells, as described in Section 4.3.2. Three (0.5-13) percent[88] of wells had a portion of the operator-reported protected ground water resource that was uncemented. Perforations used for hydraulic fracturing were

80 12,800 (7,600-18,000) wells

81 20,200 (17,500-23,000) wells

82 15,300 (10,500-20,100) wells

83 6,800 (1,600-11,900) wells

84 18,900 (15,200-22,600) wells

85 3,000 (900-5,100) wells

86 600 (10-1,500) wells

87 21,400 (18,900-24,000) wells

88 600 (10-1,800) wells

placed deeper than the base of the protected ground water resources identified by well operators in all but 0.4 (0.1-3) percent[89] of wells.

As described in Section 5, subsurface fluid movement depends on many factors, including the existence of a pathway, the presence of a fluid, and a driving force. This report focused only on the potential for well construction pathways to exist and does not address the role of other possible pathways or the role of other factors. Two potential pathways related to well construction were considered: from the inside of the well to the outside and along the outside of the well. Subsurface fluid movement to ground water resources may occur though either potential pathway or a combination of both potential pathways. The presence or absence of casing and cement along the well were evaluated to identify the number of well construction barriers to subsurface fluid movement via these potential pathways.

Wells represented in this study had a range in the number of casing and cement barriers between the inside of the production casing and the wellbore at any point along the well. The number of casing and cement barriers ranged from zero in open hole completions to six when surface, intermediate, and production casing were each cemented to the surface. The most common number of casing and cement barriers, at any point along a well, was either two (one casing string and one cement sheath) or three (two casing strings and one cement sheath). Multiple casing and cement barriers can minimize or prevent well integrity failures that could result in subsurface fluid movement, because all barriers would need to fail in order for a pathway from the inside of the well to the outside to occur.

More than half of the wells represented in this study had two or more cemented casings between the point of shallowest hydraulic fracturing and the operator-reported ground water resources. This indicates that there were often two or more barriers to subsurface fluid movement along the outside of a well, from the targeted geologic formation to protected ground water resources reported by well operators. Multiple cemented casings between the shallowest point of hydraulic fracturing and operator-reported protected ground water resources did not preclude the presence of uncemented intervals along the outside of the well. Monitoring studies of uncemented annuli indicate that uncemented intervals can be pathways for gas and liquid movement along the outside of a well. Some companies and state regulators, however, note that cementing only across critical zones (i.e., zones containing corrosive fluids, water in need of protection, or hydrocarbons) and leaving uncemented annuli allows operators to monitor uncemented annuli for subsurface fluid movement. More detailed information is presented in Section 5.2.

The survey design and data collection process may have implications for the interpretation of the results presented in this report. The results are statistically representative of oil and gas production wells hydraulically fractured by nine oil and gas service companies in the continental United States during 2009 and 2010. The extent to which these results may be statistically representative of all production wells hydraulically fractured in the United States during the same time period could not be determined. Nevertheless, comparisons between wells in this study and other data on oil and gas production in the United States during 2009 and 2010 suggest that observations made in this

[89] 90 (10-300) wells

report are likely indicative of oil and gas production wells hydraulically fractured during this time period.

Estimates of the frequency of occurrence of well design and construction characteristics are presented at the national scale. Estimates may be different for different regions of the country, because of differences in local geologic characteristics, state regulations, and company preferences. It is also possible that the estimates presented in the report may not apply to wells constructed and hydraulically fractured after 2010, if well design and construction practices have changed (e.g., a greater proportion of horizontal well completions). Additionally, the results presented in this report are generated from data provided by oil and gas well operators. The EPA did not attempt to independently and systematically verify data supplied by the operators. Consequently, the study results, which include comparisons of operator-reported protected ground water resources to well construction characteristics, are of the same quality as the supplied data.

This report presents the results of a survey of onshore oil and gas production wells hydraulically fractured in the continental United States during 2009 and 2010, using data provided by well operators. Two potential pathways for subsurface fluid movement were examined—from the inside of the well to the outside and along the outside of the well. The following key findings contribute to an understanding of the role of well design and construction practices with respect to these pathways:

> *The wells generally had multiple layers of casing and cement that can act as barriers to subsurface fluid movement by interrupting pathways for potential subsurface fluid movement.* Multiple casing and cement barriers can prevent pathways from forming, because all barriers would need to fail in order for a pathway for potential subsurface fluid movement to occur. The most common number of barriers to potential subsurface fluid movement from inside of the well to the outside, at any point along the well, was either two (one casing string and one cement sheath) or three (two casing strings and one cement sheath). Additionally, there were often two or more barriers (i.e., cemented casings) to potential subsurface fluid movement along the outside of a well, from the targeted geologic formation to operator-reported protected ground water resources.

> *While multiple barriers were often present in hydraulically fractured oil and gas production wells, pathways for potential subsurface fluid movement were identified in some wells.* Uncemented intervals have been shown to be pathways for subsurface fluid movement along the outside of the well. An estimated 66 (44-83) percent[90] of wells had one or more uncemented intervals, and 3 (0.5-13) percent[91] of wells had uncemented intervals within the operator-reported protected ground water resources. Casing perforations placed at depths shallower than the base of operator-reported protected ground water resources can create a pathway for fluids to flow from the inside of the well to a ground water resource, if a ground water resource is present at that depth. An estimated 0.4 (0.1-3) percent[92] of wells

[90] 15,300 (10,500-20,100) wells

[91] 600 (10-1,800) wells

[92] 90 (10-300) wells

had perforations used for hydraulic fracturing that were placed shallower than the base of the operator-reported protected ground water resource.

These results, as well as other information on well characteristics, the relationship between drinking water resources and hydraulically fractured wells, and casing and cement barriers that can prevent subsurface fluid movement, highlight important factors that should be considered when assessing the potential impacts of hydraulically fractured oil and gas production wells on drinking water resources.

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Appendix A: Survey Design and Confidence Intervals

A.1. Optimization Algorithm

An optimization algorithm was used to determine the number of well identifiers to be selected from each of the 31 unique operator-shale play combinations represented by the nine well operators. The optimization algorithm was designed to select a sample of 400 well identifiers across the 31 operator-shale play combinations that best maximized the geographic diversity of the sample and maximized the precision of any estimates calculated from the sample using the statistical weights described in Section 3.5.

The algorithm identified the optimal solution by minimizing a penalty function, subject to the constraints that at least two well identifiers were selected in each operator-shale play combination (or one if there was only one) and restricting the total sample size to 400. The penalty function is given in equation A.1.

$$Penalty = 1.0c_v + 0.5\sum_{j=1}^{4}\left\{\frac{(n_j - r_j)^2}{r_j}\right\} + 0.1D \qquad \text{(A.1)}$$

The first two terms in equation A.1 reflect the goals for selecting well identifiers: maximizing the precision of statistical estimates and maximizing geographic diversity. The first term is the coefficient of variation (c_v) of the statistical weights for the sample of 400 well identifiers.[93] One important method for maximizing precision is to have the final statistical weights close to equal across the entire sample of 400 well identifiers (i.e., c_v is small); this prevents a few results from dominating the entire estimate (Lohr, 2010). The statistical weights are the product of the inverse of the probabilities of selection at each stage of sampling. In the first-stage selection of well operators, the four large operators were selected with higher probabilities than the medium and small operators (Section 3.2). Balancing the statistical weights, therefore, required selecting well identifiers at a higher rate from the medium and small operators at the second stage.

The second term in equation A.1 includes a standard chi-squared statistic to measure the geographic diversity of the sample. The chi-squared statistic compares the number of well identifiers selected for each geographic region (n_j) to the expected number of well identifiers for that region assuming proportional representation (r_j). A value of zero for this term indicates that the sample of 400 well identifiers has the same geographic distribution as the service company well list.

Equation A.1 includes a third term that constrains extreme sample sizes by introducing a penalty if the number of well identifiers selected from each operator is not between 33 and 75; this controls the burden placed on the nine operators by limiting the number of well files requested from any one operator. Alternative minimum and maximums were examined as part of the optimization procedure. The penalty associated with extreme sample sizes (D) was calculated using equation A.2.

[93] The coefficient of variation is defined as the ratio of the standard deviation to the mean.

$$D = 1 + \frac{\sum_{i=1}^{9} d_i}{Var(M)} \tag{A.2}$$

where

$$d_i = (n_i - 75)^3 \quad \text{if } n_i > 75$$
$$= 0 \quad \text{if } 75 \geq n_i \geq 33$$
$$= (33 - n_i)^3 \quad \text{if } n_i < 33$$

and $Var(M)$ is equal to the variance of the number of well identifiers selected from each operator-shale play combination (M_i).

The penalty function, and thus the number of well identifiers selected from each operator-shale play combination, depends on the coefficients in each term in equation A.1. The coefficients are relative in the sense that they can all be increased by a factor of two or ten without affecting the sample size allocation. As a result, the coefficient in the first term was set to 1.0 and the other two coefficients (0.5 and 0.1) were adjusted. The exact setting of each coefficient was based on trial and error, attempting to minimize the first term, while keeping the sample size within an acceptable range and minimizing the chi-square function without having one geographic region contribute many more well identifiers in the chi-square term than the other geographic regions.

The optimal number of well identifiers from each operator-shale play combination minimized the penalty function shown in equation A.1. In the final sample of 400 well identifiers, the number of well identifiers selected for each company ranged from 16 to 77. For this sample, the estimated coefficient of variation was 0.496; two companies had well counts over 75 (77.6 and 76.2 before rounding); and the expected versus achieved sample size in each geographic region, on which the chi-squared statistic is based, were: East (expected 60.5, achieved 61.6), West (expected 102.1, achieved 98.9), South (expected 138.6, achieved 135.8), and Other (expected 98.9, achieved 103.7).

A.2. Variance Estimation and Confidence Intervals

The sampling approach used to select 400 (subsampled down to 350) well identifiers determined the approach used to estimate the variance, which is used to calculate the 95 percent confidence intervals. The sampling approach used in this study is best approximated as a stratified, two-stage sample design in which well operators were selected in the first stage and well identifiers were selected in the second stage.

As described in Section 3.2, nine well operators were selected from six strata by simple random sampling in the first stage. In the second stage, well identifiers for each of the nine well operators were stratified by shale play or shale play combination, which resulted in 31 unique combinations of well operator and shale play or shale play cluster. For eight of these combinations, or sampling strata, all well identifiers were selected in the second stage. This was the case for the three small well operators (all well identifiers from each small operator were selected) and for strata with one or two well identifiers.

The number of well identifiers selected from each of the remaining 23 strata was determined using the optimization algorithm described in Section A.1. A simple random sample of that size was then selected from each stratum. Since the optimization algorithm accounting for the number of well identifiers was a function of the total sample across all sampled operators, the selection of well identifiers from these remaining strata more closely resembled a two-phase sampling approach, rather than a two-stage sampling approach [Chapters 5 and 12 in Lohr (2010); Section 4.3 and Chapter 9 in Särndal et al. (2003)]. Even in these strata, since the resulting sample was selected within first-stage operators, the sample retains some of the characteristics of two-stage sample and its variance will be less than the general formula for two-phase variance. In the terminology of Särndal et al. (2003), the samples of well identifiers within strata were independent, but not all were invariant.

Variance Estimation. The stratified version of the standard approximation for the variance of a two-stage sample design provided by the first term of equation 5.24 in Lohr (2010) was used to estimate the variance of the sample design used in this study. While a two-phase design has a somewhat larger variance than a two-stage design, the standard approximation is reasonable in this situation that is a combination of both.

The sample sizes reflect the final sample of 350 wells. The strata for variance estimation are the first-stage strata used to select operators. Variance estimates measure the consistency (or variability) between operators within the same stratum, so each variance stratum must contain at least two operators. Thus, for variance estimation, the four large operator strata were collapsed into two variance strata, each with two sampled well operators. The other two variance strata are the strata for medium-sized operators and for small-sized operators. The formula used to estimate the variance is given in equation A.3:

$$\hat{V}\left(\hat{\theta}_x\right) = \sum_{h=1}^{4} \frac{M_h^2}{m_h} \times \left(1 - \frac{m_h}{M_h}\right) \times \hat{V}_h \tag{A.3}$$

Where $\hat{\theta}_x$ is the point estimator for the total of variable x, the well characteristic of interest (e.g., well age or true vertical depth), M_h, and m_h are the first-stage frame and sample sizes for the number of operators in variance stratum h, and

$$\hat{V}_h = \frac{1}{m_h - 1} \sum_{\mathrm{i}=1}^{m_h} (\hat{t}_i - \hat{\bar{t}}_h)^2 \tag{A.4}$$

In equation A.4, $\hat{\bar{t}}_h = m_h^{-1} \sum_{i=1}^{m_h} \hat{t}_i$ and $\hat{t}_i$ is the estimated total of variable x for company i using the second-stage conditional weights (e.g., the estimated total number of wells in company i with a cement bond log).

Confidence Intervals. To compute 95 percent confidence intervals on count or continuous variables, the estimated mean plus or minus the standard error was multiplied by a *t*-statistic with five degrees of freedom:[94]

$$\left[\hat{\theta}_x - t_{5,0.975}\sqrt{\hat{V}\left(\hat{\theta}_x\right)},\quad \hat{\theta}_x + t_{5,0.975}\sqrt{\hat{V}\left(\hat{\theta}_x\right)}\right] \tag{A.5}$$

[94] The variance formula had five degrees of freedom because nine companies were selected across four variance strata. Degrees of freedom are calculated as the number of first-stage units (9) minus the number of variance strata (4).

where $t_{5,0.975}$ is the 97.5 percentile of a t-distribution with five degrees of freedom. If the lower end of the confidence interval was below 10, it was set to 10 to avoid disclosure about the actual sampled responses.

Variance estimates for proportions in the Executive Summary and Section 8 were handled differently, because many point estimates were near 0 or 100 percent. Wilson confidence intervals were used to constrain the limits to remain above 0.0 percent and below 100 percent (Heeringa et al., 2010). The formula for the 95-percent Wilson confidence intervals is provided in equation A.6.

$$\left[\frac{(2n^*p+t^2)-\left(t\sqrt{t^2+4p(1-p)n^*}\right)}{2(n^*+t^2)}, \quad \frac{(2n^*p+t^2)+\left(t\sqrt{t^2+4p(1-p)n^*}\right)}{2(n^*+t^2)}\right] \tag{A.6}$$

Where n^* is the effective sample size (i.e., number of wells, adjusting for the correlation of wells within operators); $t = t_{5,0.975}$, the 97.5 percentile of a t-distribution with five degrees of freedom; and p is the estimated weighted proportion.

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Appendix B: Well Operator Information Request

In August 2011, the EPA issued information requests to nine well operators to collect data used in this report. The requests were sent to the following companies: Clayton Williams Energy, Inc.; ConocoPhillips; EQT Corporation; Hogback Exploration, Inc.; Laramie Energy II, LLC; MDS Energy, Ltd.; Noble Energy, Inc.; SandRidge Exploration and Production, LLC; and Williams Production Company, LLC. These companies were chosen to reflect a range in operator size and geographic diversity of oil and gas production wells hydraulically fractured by nine service companies. The EPA requested information for a total of 350 well identifiers. The information requested is stated below.

INFORMATION REQUESTED

Your response to the following questions is requested within thirty (30) days of receipt of this information request:

For each well listed in Enclosure 5 of this letter (not provided here), provide any and all of the following information:

Geologic Maps and Cross Sections

1. Prospect geologic maps of the field or area where the well is located. The map should depict, to the extent known, the general field area, including the existing production wells within the field, preferably showing surface and bottom-hole locations, names of production wells, faults within the area, locations of delineated source water protection areas, and geologic structure.

2. Geologic cross section(s) developed for the field in order to understand the geologic conditions present at the wellbore, including the directional orientation of each cross section such as north, south, east, and west.

Drilling and Completion Information

3. Daily drilling and completion records describing the day-by-day account and detail of drilling and completion activities.

4. Mud logs displaying shows of gas or oil, losses of circulation, drilling breaks, gas kicks, mud weights, and chemical additives used.

5. Caliper, density, resistivity, sonic, spontaneous potential, and gamma logs.

6. Casing tallies, including the number, grade, and weight of casing joints installed.

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7. Cementing records for each casing string, which are expected to include the type of cement used, cement yield, and wait-on-cement times.

8. Cement bond logs, including the surface pressure during each logging run, and cement evaluation logs, radioactive tracer logs or temperature logs, if available.

9. Pressure testing results of installed casing.

10. Up-to-date wellbore diagram.

Water Quality, Volume, and Disposition

11. Results from any baseline water quality sampling and analyses of nearby surface or groundwater prior to drilling.

12. Results from any post-drilling and post-completion water quality sampling and analyses of nearby surface or groundwater.

13. Results from any formation water sampling and analyses, including data on composition, depth sampled, and date collected.

14. Results from chemical, biological, and radiological analyses of "flowback," including date sampled and cumulative volume of "flowback" produced since fracture stimulation.

15. Results from chemical, biological, and radiological analyses of "produced water," including date sampled and cumulative volume of "produced water" produced since fracture stimulation.

16. Volume and final disposition of "flowback."

17. Volume and final disposition of "produced water."

18. If any of the produced water or flowback fluids were recycled, provide information, including, but not limited to, recycling procedure, volume of fluid recycled, disposition of any recycling waste stream generated, and what the recycled fluids were used for.

Hydraulic Fracturing

19. Information about the acquisition of the base fluid used for fracture stimulation, including, but not limited to, its total volume, source, and quality necessary for successful stimulation. If the base fluid is not water, provide the chemical name(s) and CAS number(s) of the base fluid.

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20. Estimate of fracture growth and propagation prior to hydraulic fracturing. This estimate should include modeling inputs (e.g., permeability, Young's modulus, Poisson's ratio) and outputs (e.g., fracture length, height, width).

21. Fracture stimulation pumping schedule or plan, which would include the number, length, and location of stages; perforation cluster spacings; and the stimulation fluid to be used, including the type and respective amounts of base fluid, chemical additives and proppants planned.

22. Post-fracture stimulation report containing, but not limited to, a chart showing all pressures and rates monitored during the stimulation; depths stimulated; number of stages employed during stimulation; calculated average width, height, and half-length of fractures; and fracture stimulation fluid actually used, including the type and respective amounts of base fluid, chemical additives and proppants used.

23. Micro-seismic monitoring data associated with the well(s) listed in Enclosure 5, or conducted in a nearby well and used to set parameters for hydraulic fracturing design.

Environmental Releases

24. Spill incident reports for any fluid spill associated with this well, including spills by vendors and service companies. This information should include, but not be limited to, the volume spilled, volume recovered, disposition of any recovered volume, and the identification of any waterways or groundwater that was impacted from the spill and how this is known.

Glossary

Annulus: The space between two concentric objects, such as between the wellbore and casing or between casing and tubing. (ref 6)

Borehole: The wellbore itself, including the open hole or uncased portion of the well. (ref 6)

Casing: Steel pipe that is lowered into a wellbore. Casing extends from the bottom of the hole to the surface. (ref 6)

> **Conductor casing:** Casing that is generally less than 100 feet deep and is often uncemented. Its purpose is to prevent the in-fill of unconsolidated dirt and rock in the uppermost few feet of drilled hole. (refs 1, 3)
>
> **Intermediate casing:** Casing that seals off intermediate depths and geologic formations that may have considerably different reservoir pressures than deeper zones to be drilled. (refs 1, 3)
>
> **Production casing:** The deepest casing set and serves primarily as the conduit for producing fluids, although when cemented to the wellbore, this casing can also serve to seal off other subsurface zones including ground water resources (refs 1, 3). For this report, any casing or liner with production perforations was considered to be a "production casing." In some cases, this can include casing identified as "intermediate" by the operator, but later perforated for production purposes.
>
> **Surface casing:** The shallowest cemented casing, with the widest diameter. Cemented surface casing generally serves as an anchor for blowout protection equipment and to seal off certain ground water resources. (ref 1)

Casing string: An assembled length of steel pipe configured to suit a specific wellbore. The sections of pipe are connected and lowered into a wellbore, then fixed in place using cement or packers. (ref 6)

Casing tally: Often provided by well operators, this is a detailed list of the sections of casing placed into the well during its construction, including the precise length of each section.

Cementing: To prepare and pump cement into place in a wellbore. Cement is placed between the outside of the casing and the inside of the drilled hole in order to seal off the annulus. Cement also provides support behind the casing and protects it from corrosive fluids in the subsurface. (refs 1, 6, 7)

> **Primary cementing:** The first cementing operation performed to place a cement sheath around a casing or liner. (ref 6)
>
> **Secondary cementing:** Defined in this report as any non-primary cementing operation. Secondary cementing operations are also referred to as "remedial" cementing operations. (refs 5, 6)

Cementing ticket: Often provided by well operators, this is a description of the cementing job. The description usually includes how much cement of a specific type was used, how much volume the cement occupies when cured, the amount of cement additives used, and the pumping pressures used to place the cement.

Cement bond log: A log that uses the variations in amplitude of an acoustic signal while traveling down the casing wall to evaluate the cement bond between the cement, casing, and wellbore. (ref 6)

Cement top: Defined in this report as the height above the bottom of the casing string reached by cement in the wellbore, as measured from the surface.

Completion: A generic term used to describe the events and equipment necessary to bring a well into production (ref 6). Completion activities can include hydraulic fracturing.

Completion report: Often provided by well operators, this is a daily log of the completion activities at a well after it has been drilled. Hydraulic fracturing is included in the completion report.

Deviated well: Defined in this report as a non-horizontal well where the bottom-hole location is more than 500 lateral feet from the surface location.

Deviation survey: A completed measurement of the inclination (deviation from vertical) and azimuth (the compass direction) of a location in a well (typically the total depth at the time of measurement). (ref 6)

Drill bit: The tool used to crush or cut rock. Most bits work by scraping or crushing the rock as part of a rotational motion, while some bits work by pounding the rock vertically. (ref 6)

Drilling fluid: Any of a number of liquid and gaseous fluids and mixtures of fluids and solids used when drilling boreholes. (ref 6)

Driller's report: Often provided by well operators, this is a daily log of the activities at a well and includes details on the well's drilling, casing, and cementing history from surface to total depth.

Drinking water resource: Any body of water, ground or surface, that currently serves or in the future could serve as a source of drinking water for public or private water supplies. (ref 9)

Formation: A body of earth material with distinctive and characteristic properties and degree of homogeneity in its physical properties. (ref 8)

Ground water resource: Defined in this report as any geologic formation containing ground water.

Horizontal well: Defined in this report as a well intentionally completed with one or more boreholes drilled laterally to follow the targeted geologic formation.

Hydraulic fracturing: A stimulation technique used to increase production of oil and gas. Hydraulic fracturing involves the injection of fluids under pressures great enough to fracture the oil- and gas-production formations. (ref 9)

Liner: A casing string that does not extend to the top of the wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string. (ref 6)

Lithology: The macroscopic nature of the mineral content, grain size, texture, and color of rocks. (ref 6)

> **Carbonate:** A class of sedimentary rock whose chief mineral constituents are calcite, aragonite, and dolomite. (ref 6)
>
> **Chert:** A sedimentary rock and a variety of quartz made of extremely fine-grained silica. (ref 6)
>
> **Coal:** A carbon-rich sedimentary rock that forms from the remains of plants deposited as peat in swampy environments. (ref 6)
>
> **Sandstone:** A clastic sedimentary rock whose grains are predominantly sand-sized. Sandstone has relatively high porosity and permeability. (ref 6)
>
> **Shale:** A fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. (ref 6)

Losses of circulation: The reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string. (ref 6)

Measured depth: The length of the wellbore, as if determined by a measuring stick. This measurement differs from the true vertical depth of the well in all but vertical wells. (ref 6)

Mud log: Often provided by well operators, this is a detailed profile of the drilled hole describing the presence or absence of oil or gas in the various rock formations penetrated by the drill bit. The drilling fluid and rock cuttings returned to the surface are tested at the surface and correlated with their depth to produce the log. (ref 3)

Open hole: The uncased portion of a well. All wells, when first drilled, have open sections. Additionally, some completions are open. (ref 6)

Open hole log: Often provided by well operators, this is a generic term applied to any electric wireline log run in a part of the wellbore that has no casing set. Open hole logs are generally run to understand the hydrocarbon-bearing potential along the logged interval.

Packer: A device that can be run into a wellbore with a smaller initial outside diameter that then expands to seal the wellbore. (ref 6)

Perforation: The communication tunnel created from the casing or liner into the targeted geologic formation through which injected fluids and oil or gas flow. (ref 6)

Plat: Often provided by well operators, this is a map or plan-view depiction of the well site.

Point of shallowest hydraulic fracturing: Defined in this report as the measured depth of the shallowest point at which hydraulic fracturing occurred.

Protected ground water resources: This report does not use a single definition for protected ground water resources and relies solely on information provided to the EPA by well operators.

Spud: To start the well drilling process by removing rock, dirt, and other sedimentary material with the drill bit. (ref 6)

Stratified sampling approach: In a stratified sampling approach, the population is divided into subpopulations, called strata. The strata do not overlap and they constitute the whole population, so that each sampling unit belongs to exactly one stratum. An independent, random sample can then be selected from each strata. Information from all strata are pooled to obtain overall population estimates. (ref 4)

Targeted geologic formation: Defined in this report as the geologic formation intended for hydrocarbon production.

True vertical depth: The vertical distance from a point in the well (usually the current or final depth) to a point at the surface. (ref 6)

Tubing: The narrowest steel pipe set within a completed well, either hung directly from the wellhead or secured at its bottom using a packer. Tubing is not typically cemented in the well.

Uncemented annulus: Defined in this report as an uncemented interval that reaches the surface.

Uncemented interval: Defined in this report as a segment of annular space along the outside of the well (between the casing and the wellbore wall) that has no cement.

Vertical well: Defined in this report as a well with a bottom-hole location within 500 lateral feet of the surface location.

Wellbore: The drilled hole or borehole, including the open hole or uncased portion of the well. (ref 6)

Wellbore diagram: A schematic diagram that identifies the main completion components installed in a wellbore. The information included in the wellbore diagram relates to the principal dimensions of the components and the depth at which the components are located. (ref 6)

Wellhead: The surface termination of a wellbore. (ref 6)

Zonal isolation: Wells that prevent inter-formational flow are said to have "zonal isolation." (refs 1, 2, 7)

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