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

Hydraulic Fracturing Operations

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 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: Hydraulic Fracturing Operations*, 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 has produced multiple EPA technical reports and scientific journal publications that collectively advance understanding of the potential impacts of hydraulic fracturing for oil and gas on drinking water resources and identify factors that may influence those impacts. The products of the EPA's study also facilitate and inform dialogue among interested stakeholders, including Congress, other Federal agencies, states, tribal governments, 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-15-022

Susan Burden, PhD, US EPA

Charles J. Hillenbrand, PhD, US EPA

Andrea T. Joffe, BS, Randstad Technologies, under contract EP-D-12-050

David Marker, PhD, Westat, under contract EP-D-12-050

Susan L. Sharkey, MA, US EPA

Steve Souders, BS, US EPA

Chuck Tinsley, BS, 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 hydraulic fracturing operations and monitoring and testing activities. The meeting was held in Dallas, Texas, on May 3, 2016, and included representatives from the following state agencies:

Arkansas Department of Environmental Quality

Colorado Department of Public Health and Environment

Colorado Oil and Gas Conservation Commission

Louisiana Department of Environmental Quality

New Mexico Energy, Minerals, and Natural Resources Department

North Dakota Industrial Commission

Oklahoma Corporation Commission

Oklahoma Secretary of Energy and Environment

Pennsylvania Department of Environmental Protection

Railroad Commission of Texas

Texas Commission on Environmental Quality

Wyoming Oil and Gas Conservation Commission

Executive Summary

In 2010, the US Environmental Protection Agency (EPA) conducted a survey of onshore oil and gas production wells hydraulically fractured by nine oil and gas service companies in support of the Agency's *Study of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources*.[1] Data from the survey were first used to describe the relationship of well design and construction characteristics to drinking water resources and the number and relative location of well construction barriers (e.g., casing and cement) that can block pathways for potential subsurface fluid movement in *Review of Well Operator Files for Hydraulically Fractured Oil and Gas Production Wells: Well Design and Construction*.[2] The current report provides insights into the potential for hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, to move to underground drinking water resources during hydraulic fracturing, based on additional analyses of data collected during the survey.

The objective of this report was to explore the role of the following factors in subsurface fluid movement during hydraulic fracturing:

(1) the ability of the hydraulically fractured production well to transport fluids through the well to and from the targeted rock formation without leaking and to prevent fluid movement along the outside of the well (i.e., the mechanical integrity of the well), and
(2) the potential intersection of newly-created fractures with underground drinking water resources or nearby existing pathways (e.g., faults or nearby production wells).

The scope of the report is limited to the information collected during the EPA's survey of oil and gas production wells hydraulically fractured by the nine service companies. As part of the survey, 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 to the EPA by the nine service companies. Drilling, construction, and completion information for the selected study wells was collected from nine well operators and summarized. Data describing hydraulic fracturing characteristics and monitoring and testing activities for the study wells are statistically representative of an estimated 23,200 wells that were hydraulically fractured by the nine service companies between approximately September 2009 and September 2010. The results are presented as estimates of occurrence with 95 percent confidence intervals.

Hydraulic Fracturing Characteristics

One hydraulic fracturing job was identified for 84 (95 percent confidence interval: 67-94) percent of the 23,200 (21,400-25,000) wells represented in this study, and two or more hydraulic

[1] Information on the EPA's *Study of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources* is available at www.epa.gov/hfstudy.

[2] US EPA. 2015b. *Review of Well Operator Files for Hydraulically Fractured Oil and Gas Production Wells: Well Design and Construction*. Office of Research and Development, Washington, DC. EPA/601/R-14/002. Available at http://www2.epa.gov/hfstudy/review-well-operator-files-hydraulically-fractured-oil-and-gas-production-wells-well-design.

fracturing jobs were identified for 16 (6-33) percent of the wells.[3] Because some wells were hydraulically fractured more than once, there were an estimated 28,500 (25,100-31,900) hydraulic fracturing jobs conducted at the wells represented in this study. The majority of the jobs [71 (60-80) percent] were conducted between September 30, 2009, and September 30, 2010.

Hydraulic fracturing jobs were categorized as initial fracture treatments, re-completions, or re-fractures, depending on the timing and depth interval over which hydraulic fracturing was conducted in the well. For this report, initial fracture treatments were defined as the first reported hydraulic fracturing job conducted at a well, regardless of the depth interval at which hydraulic fracturing occurred. A re-completion was defined as a job in which no portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job. Under this definition, a re-completion can include hydraulic fracturing of previously un-fractured portions of a well within the same geologic formation and hydraulic fracturing of previously un-fractured portions of a well within a different geologic formation. A re-fracture was defined as a job in which any portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job. Of the 28,500 (25,100-31,900) hydraulic fracturing jobs, 81 (71-89) percent were initial fracture treatments, 11 (5-23) percent were re-completions, and 8 (5-12) percent were re-fractures.

The age of well components (i.e., casing, cement, and packers) at the time of hydraulic fracturing was estimated by comparing the start date of the hydraulic fracturing job to the date drilling started at the well.[4] From this comparison, the estimated age of well components at the time of hydraulic fracturing ranged from less than one month to approximately 50 years. Sixty-four (48-77) percent of the hydraulic fracturing jobs were conducted in wells having well components less than six months old. The estimated age of well components at the time of an initial fracture treatment (median value of 45 days) was generally smaller than the estimated age of well components for either a re-completion or a re-fracture (median value of six years).

Monitoring and Testing Activities

Four types of monitoring and testing activities were reviewed in this study: casing pressure tests, surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring. Each type of monitoring and testing activity can provide information on subsurface fluid movement during hydraulic fracturing, because they provide information on either the mechanical integrity of the well, fracture growth, or the potential intersection of induced fractures with existing pathways. The number of different types of monitoring and testing activities reported for a single hydraulic fracturing job varied, from no indication of any of the monitoring or testing activities considered in this study to the use of all four types. Two or more of the monitoring and testing activities were

[3] For this report, a single hydraulic fracturing job consisted of one or more hydraulic fracturing stages in which the time between consecutive stages was less than or equal to 90 days. A hydraulic fracturing stage refers to a specific measured depth interval for which hydraulic fracturing began on a specific date.

[4] Hydraulic fracturing jobs conducted using a temporary frac string were not included in this analysis. Temporary frac strings are installed in a well, used for hydraulic fracturing, and then removed from the well when hydraulic fracturing is complete.

reported to have occurred for 76 (62-86) percent of the hydraulic fracturing jobs. No evidence of any of the monitoring or testing activities was found for 2 (1-5) percent of the jobs.

Casing pressure tests, which can provide information on the mechanical integrity of the well, were reported to have been conducted for 57 (44-70) percent of the hydraulic fracturing jobs. Surface treating pressure monitoring was reported for 97 (94-99) percent of the hydraulic fracturing jobs. The surface treating pressure is the pressure observed at the surface when hydraulic fracturing fluids are injected into the casing string used for hydraulic fracturing. Changes in the surface treating pressure can provide information on the mechanical integrity of the well and, under a given set of assumptions, estimate fracture growth. Annular pressure monitoring was reported in 53 (27-77) percent of the hydraulic fracturing jobs. Annular pressure monitoring can measure the pressure in the annular space between nested casing strings or between the casing and the surrounding geology. Pressure increases in the annular space can indicate the introduction of fluids into the space from the surrounding geology or through a leak in the casing, cement, or packer (if present). Microseismic monitoring was reported to have been conducted during 0.5 (0.1-2) percent of the hydraulic fracturing jobs. Microseismic monitoring maps microseismic events that occur during hydraulic fracturing. These events are assumed to be indicative of fracture growth during hydraulic fracturing.

Because information in the well files was sometimes insufficient to conclusively determine whether the monitoring or testing activities reviewed in this study occurred, estimates of the occurrence of monitoring and testing activities presented in this report may be underestimates. Similarly, estimates of the lack of monitoring or testing activities may be overestimates.

Subsurface Fluid Movement During Hydraulic Fracturing

The potential for hydraulic fracturing fluids, or fluids naturally present in the subsurface, to move to underground drinking water resources during hydraulic fracturing depends on many factors. In general, these factors include, but are not limited to, the design and construction of the hydraulically fractured production well, the design and execution of the hydraulic fracturing job, the characteristics of subsurface rock formations, and the relative location of induced fractures to underground drinking water resources or existing pathways that may lead to drinking water resources. Together, these factors affect how fluids move through the subsurface during hydraulic fracturing and whether they can reach underground drinking water resources.

Data obtained in this study provide insight on the role of mechanical integrity and the potential intersection of newly-created fractures with underground drinking water resources or existing pathways in subsurface fluid movement during hydraulic fracturing. These factors are the focus of this report, because the available data are most relevant to these factors.

Mechanical Integrity. The mechanical integrity of a well depends on the mechanical integrity of the individual components of the well. During hydraulic fracturing, pressure is applied to the inside of the production casing or, if used, a temporary frac string. When these well components have mechanical integrity, the hydraulic fracturing fluid remains in the production casing or the temporary frac string and reaches the targeted geologic formation without moving into the annular space behind the production casing or the temporary frac string. When the well components used for hydraulic fracturing do not have mechanical integrity or lose mechanical integrity during hydraulic fracturing, fluids can move outside of the production casing or the temporary frac string into one or more of the annular spaces in the well. If multiple casings and cement sheaths are present within a well, they can block fluid movement into the surrounding environment by serving as additional barriers between the invaded annular space and the surrounding geology. A well integrity failure occurs when no barriers (e.g., casing and cement) are left to block fluid from entering the surrounding environment.

Failures associated with downhole well components used for hydraulic fracturing were reported by well operators in 3 (1-8) percent of the hydraulic fracturing jobs.[5] For some hydraulic fracturing jobs, these events were reported using phrases such as "communication to surface" or "casing leak." For other jobs, these events were inferred from information available in the well files. For example, "came around" and "annular pressure increase" were interpreted as well component failures during hydraulic fracturing when written descriptions of the well's status and well operations indicated a well component failure. In all of these cases, information in the well files suggested that hydraulic fracturing fluid flowed from the inside of the casing string used for hydraulic fracturing to one or more of the annular spaces behind the casing string.

Well component failures occurred during initial fracture treatments, re-completions and re-fractures, and in jobs conducted using a temporary frac string. When compared to the larger population of hydraulic fracturing jobs, a greater proportion of jobs conducted using a temporary frac string reported a well component failure [20 (7-46) percent] than jobs that did not use a temporary frac string [0.9 (0.2-3) percent]. This observation suggests that temporary frac strings were less effective at containing fluids during hydraulic fracturing than permanent well components. Additionally, 6 (2-19) percent of re-fractures and re-completions reported a well component failure during hydraulic fracturing, compared to 2 (0.5-8) percent of initial fracture treatments. While the confidence intervals overlap, the point estimates suggest that re-fractures and re-completions may have been more likely than initial fracture treatments to experience a well component failure during hydraulic fracturing.

When well component failures were reported, well operators generally stopped the hydraulic fracturing job, addressed the cause of the failure, and completed the job. There were often multiple barriers (e.g., casing and cement) between the well components that failed and operator-reported protected ground water resources. As noted above, multiple casings and cement sheaths can block fluid movement into the surrounding environment by serving as additional barriers between the invaded annular space and the surrounding geology. There was no evidence in the well files to suggest that these additional barriers failed. However, there were well component failures in which there were no additional barriers between the casing string used for hydraulic fracturing and the operator-reported protected ground water resource (i.e., a well integrity failure). Well integrity

[5] The reported occurrence of annular pressure monitoring may have implications for the reported occurrence of well component failures. Well component failures may not have been observed and documented in the well files if annular pressure monitoring was not conducted during hydraulic fracturing. Because the reported occurrence of annular pressure monitoring was 53 (27-77) percent, some hydraulic fracturing jobs may have experienced well component failures that were not detected. Therefore, the estimated occurrence of well component failures [3 (1-8) percent of hydraulic fracturing jobs] may be an underestimate.

failures were reported in 0.5 (0.1-2) percent of all of the hydraulic fracturing jobs. Information in the well files suggested that, in these cases, hydraulic fracturing fluid entered the annular space between the casing string used for hydraulic fracturing and the surrounding geology at depths corresponding to the protected ground water resource reported by the well operator. Based on the information contained in the well files, it was not possible to determine whether fluid moved from the annular space into protected ground water resources in these cases.

Potential Intersection of Newly-Created Fractures with Operator-Reported Protected Ground Water Resources. Information on the potential intersection of induced fractures with protected ground water resources reported by well operators was available for two cases: (1) hydraulic fracturing jobs with microseismic monitoring, which provides information on how far up fractures grow, and (2) wells in which the point of shallowest hydraulic fracturing was above the base of the operator-reported protected ground water resource.

In the first case, the depths of the maximum vertical component of fracture growth estimated from microseismic monitoring data were compared to the depths of the operator-reported protected ground water resources. This comparison was done for individual hydraulic fracturing jobs that had microseismic monitoring data [0.5 (0.1-2) percent of the hydraulic fracturing jobs]. The difference between these values was used to assess whether induced fractures could have extended directly through the geologic strata to protected ground water resources reported by well operators.[6] Among the hydraulic fracturing jobs in which microseismic monitoring was conducted, induced fractures grew no closer than 5,000 feet below the base of the operator-reported protected ground water resource. For these hydraulic fracturing jobs, the potential for induced fractures to intersect operator-reported protected ground water resources was likely low, because the distance separating the estimated fracture depth and the operator-reported base of the protected ground water resource was much larger (at least 5,000 feet) than the maximum vertical component of fracture growth estimated from microseismic monitoring data.

In the second case, the estimated separation distance between the point of shallowest hydraulic fracturing in the well and the base of the operator-reported protected ground water resource was used to evaluate the potential for induced fractures to reach protected ground water resources in the absence of information on fracture growth. As reported in US EPA (2015b), the estimated separation distance was less than zero feet in 0.4 (0.1-3) percent of the wells. In these wells, perforations used for hydraulic fracturing were placed shallower than the depth of the base of the operator-reported protected ground water resource. When perforations used for hydraulic fracturing are shallower than the base of the operator-reported protected ground water resource, the potential for induced fractures to directly intersect with the protected ground water resource is high, if the protected ground water resource is present at that depth. Based on the information

[6] The maximum vertical component of fracture growth estimated from microseismic monitoring data ranged from 380 feet to 1,340 feet per hydraulic fracturing job (median value of 680 feet per job). The maximum lateral component of fracture growth estimated from microseismic monitoring data ranged from 700 feet to 2,250 feet per job (median value of 1,000 feet per job).

contained in the well files, it was not possible to determine whether hydraulic fracturing fluid entered protected ground water resources in these cases.

For the majority of the wells represented in this study, it was not possible to assess with a high degree of certainty the potential for induced fractures to intersect operator-reported protected ground water resources, because they did not fall into either of the cases described above. The above cases, however, highlight the importance of the vertical separation distance between the point of shallowest hydraulic fracturing in a well and the base of protected ground water resources. If the vertical separation distance is less than, or comparable to, the vertical component of fracture growth, induced fractures may potentially reach protected ground water resources. Conversely, if the vertical separation distance is greater than the vertical component of fracture growth, induced fractures are unlikely to extend directly into protected ground water resources.

Potential Intersection of Newly-Created Fractures with Existing Pathways. If newly-created fractures intersect with other features in the subsurface, hydraulic fracturing fluids may flow into these features. Examples of these features include, but are not limited to, existing faults, natural fracture systems, nearby oil and gas production wells, and uncemented intervals within the hydraulically fractured production well. Information on the relative location of induced fractures to existing faults, natural fracture systems, and nearby wells was generally not found in the data obtained from well operators.

Hydraulic fracturing at a well was reported to have affected a nearby oil and gas production well in 1 (0.4-4) percent of the wells represented in this study.[7] These events are often referred to as "frac hits" and were reported in the well files using the phrase "frac'd into [well name]." It was not possible to determine whether hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, reached operator-reported protected ground water resources during the frac hits, because information available in the well files was insufficient to determine whether fluids flowed along the outside of the nearby oil and gas production well and into protected ground water resources.

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 the onshore oil and gas production wells hydraulically fractured by the nine oil and gas service companies between approximately September 2009 and September 2010. Estimates of the frequency of occurrence of hydraulic fracturing characteristics and monitoring and testing activities are summarized at the national level. The estimates may be different for different regions of the country, because of differences in local geologic characteristics, regulatory requirements, and company preferences. The estimates may also not apply to wells hydraulically fractured after 2010, as hydraulic fracturing practices and regulatory requirements change over time.

[7] Frac hits are often detected through changes in pressure or fluid production at nearby wells. Because this study collected information for the study wells and not wells near study wells, the reported occurrence of frac hits may be an underestimate.

The results presented in this report are generated from data provided by oil and gas well operators. The data are limited in scope to the information requested by the EPA and the information provided by the well operators. While quality assurance and quality control measures were used to ensure that analyses presented in this report accurately reflect the data supplied by the well operators, the EPA did not attempt to independently and systematically verify the data. Consequently, the study results reflect the scope of the information request and are of the same quality as the supplied data and the analyses conducted by the EPA.

Summary

This report presents the results of a survey of onshore oil and gas production wells hydraulically fractured by nine oil and gas service companies in the United States during 2009 and 2010. Two factors that affect the potential for subsurface fluid movement during hydraulic fracturing were examined: the mechanical integrity of the hydraulically fractured oil and gas production well and the potential intersection of newly-created fractures with protected ground water resources reported by well operators or nearby existing pathways.

Situations that potentially allowed hydraulic fracturing fluids to move to protected ground water resources reported by well operators were identified in a small number of wells. These situations included:

> *Well integrity failures during hydraulic fracturing [0.5 (0.1-2) percent of the hydraulic fracturing jobs].* In these cases, well components (e.g., casing, cement, or packers) failed during hydraulic fracturing, and no additional casing or cement barriers separated the well components that failed from the operator-reported protected ground water resources. Information in the well files suggested that, in these cases, hydraulic fracturing fluid entered the annular space between the casing string used for hydraulic fracturing and the surrounding geology at depths corresponding to protected ground water resources reported by well operators. Based on the information contained in the well files, it was not possible to determine whether hydraulic fracturing fluid moved from the annular space into protected ground water resources in these cases.

> *Perforations used for hydraulic fracturing were shallower than the base of protected ground water resources reported by well operators [0.4 (0.1-3) percent of the wells] (US EPA, 2015b).* When perforations used for hydraulic fracturing are shallower than the base of the operator-reported protected ground water resource, the potential for induced fractures to directly reach the protected ground water resource is high, if the protected ground water resource is present at that depth. Based on the information contained in the well files, it was not possible to determine whether hydraulic fracturing fluid entered protected ground water resources in these cases.

Information on the relative location of newly-created fractures to existing pathways was generally not found in the well files, although 1 (0.4-4) percent of the wells reported a frac hit. Frac hits occurred when hydraulic fracturing at a well affected a nearby oil and gas production well. It was not possible to determine whether hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, reached operator-reported protected ground water resources during the frac hits, because available information in the well files was insufficient to determine whether fluids flowed along the outside of the nearby oil and gas production well and into protected ground water resources.

These results, as well as other information on hydraulic fracturing characteristics and monitoring and testing activities before and during hydraulic fracturing, highlight important well design, construction, and operation practices that should be considered when assessing the potential impacts of hydraulic fracturing on drinking water resources.

1. Introduction

Hydraulic fracturing is used to increase oil and gas production from underground rock formations. During hydraulic fracturing, a specially engineered fluid is injected down an oil and gas production well and into a targeted geologic formation at pressures great enough to create and grow fractures in the oil- and gas-containing rock. When the applied pressure is released, the natural pressure in the rock formation moves oil and gas from the formation through the newly-created fractures and the production well to the surface, where it is collected for distribution.

Concerns have been raised about the potential for hydraulic fracturing to negatively impact drinking water resources through the subsurface movement of gases and liquids (i.e., fluids) to ground water resources [Council of Canadian Academies, 2014; Kissinger et al., 2013; Rozell and Reaven, 2012; US Environmental Protection Agency (US EPA), 2011a]. To better understand the role of well construction and hydraulic fracturing in subsurface fluid movement, the US Environmental Protection Agency (EPA) conducted a survey of onshore oil and gas production wells hydraulically fractured by nine oil and gas services companies in 2009 and 2010. Data collected during the survey were first used to describe the well design and construction characteristics of these wells in *Review of Well Operator Files for Hydraulically Fractured Oil and Gas Production Wells: Well Design and Construction* (US EPA, 2015b). That report examined the relationship of well design and construction characteristics to drinking water resources and the number and relative location of well construction barriers (e.g., casing and cement) that can block pathways for potential subsurface fluid movement.

The current report provides insights into the potential for hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, to move to underground drinking water resources during hydraulic fracturing, based on additional analyses of information collected during the survey. The objective of this report was to explore the role of the following factors in subsurface fluid movement during hydraulic fracturing:

(1) the ability of the hydraulically fractured production well to transport fluids through the well to and from the targeted rock formation without leaking and to prevent fluid movement along the outside of the well (i.e., the mechanical integrity of the well), and
(2) the potential intersection of newly-created fractures with underground drinking water resources or nearby existing pathways (e.g., faults or nearby production wells).

The scope of the report is limited to the information collected during the EPA's survey of oil and gas production wells hydraulically fractured by the nine service companies (US EPA, 2015b). Data collected during the survey were used to describe hydraulic fracturing at these wells and the reported occurrence of monitoring and testing activities that provide information about subsurface fluid movement during hydraulic fracturing. Results presented in this report are statistically representative of the oil and gas production wells hydraulically fractured by the nine service companies.

2. Hydraulic Fracturing Overview

Oil and gas production wells are designed, constructed, and completed to access hydrocarbon resources in targeted geologic formations. Hydraulic fracturing is a completion activity that occurs after a well has been constructed.[8] Characteristics of hydraulic fracturing operations depend on how the production well is constructed and completed in the targeted geologic formation and on the properties of the targeted geologic formation, including *in situ* stresses and other geomechanical rock properties (Hlidek and Weijers, 2007; Martin and Valkó, 2007). Well completion in the targeted geologic formation can vary. Figure 1 illustrates the different types of well completions observed in this study: cemented casing, formation packer, and open hole.

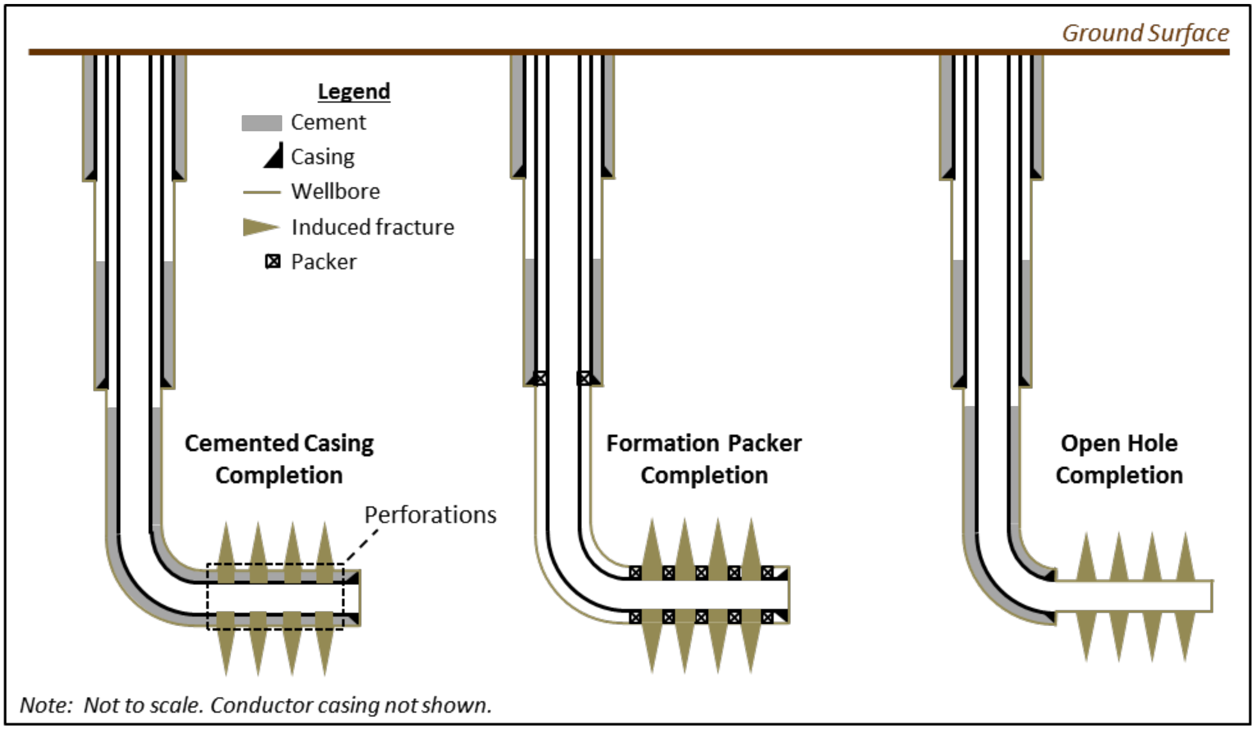

Figure 1. Well completion types reported in the well operators' files. Well completions are depicted for horizontal well orientations, but may occur in vertical or deviated wells. (US EPA, 2015b)

Cemented casing completions have both casing (e.g., steel pipe) and cement in the targeted geologic formation. In these completions, the casing and cement are perforated, and hydraulic fracturing is performed within the perforated interval. Formation packer completions also have casing in the targeted geologic formation, but use mechanical devices (i.e., packers) to seal the annular space between the uncemented production casing and the surrounding geologic formation. 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 into the surrounding rock formation. Open hole completions contain no casing and, therefore, no cement in the targeted geologic zone. Hydraulic

[8] Section 2 of US EPA (2015b) provides a general overview of the design and construction of oil and gas production wells.

fracturing in an open hole completion occurs within the open hole interval and may be conducted using a temporary frac string. If a temporary frac string is used, it is lowered into the well and secured at its base using a packer or by latching into existing well components located in the well. Hydraulic fracturing takes place through the temporary frac string, which is removed when hydraulic fracturing is complete.

A hydraulic fracturing job occurs within a designated portion (i.e., interval) of an oil and gas production well. Jobs can be conducted in a single stage or in multiple stages. In a single stage job, the entire designated portion of the well is hydraulically fractured at the same time. In a multi-stage job, discrete intervals are sequentially isolated and hydraulically fractured until the entire designated portion of the well has been hydraulically fractured. In each stage, hydraulic fracturing fluid is injected down the well at a calculated, predetermined rate and pressure [Ground Water Protection Council (GWPC) and ALL Consulting, 2009], although changes in how a hydraulic fracturing job progresses are often made at the well site as the job is executed and monitored (Malone and Ely, 2007).[9] The fluid creates and propagates fractures by transferring the pressure applied at the surface to the targeted geologic formation (Gupta and Valkó, 2007). The fluid also carries proppants into the newly-created fractures; proppants are small, incompressible particles (e.g., sand) that keep the fractures open once the injection pressure has been released and production begins (Brannon and Pearson, 2007; Gupta and Valkó, 2007).

3. Research Methods

Data used in this report were provided by nine oil and gas production well operators for 323 study wells in response to an information request letter sent in August 2011.[10] The well operators and study wells were selected from a list of onshore oil and gas production wells that were reported by the nine service companies to have been hydraulically fractured between approximately September 2009 and September 2010.[11] The letter requested, for each study well, 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. 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. (US EPA, 2015b)

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

[9] Hydraulic fracturing fluids are often water-based fluids that contain chemical additives (GWPC and ALL Consulting, 2009; Gupta and Valkó, 2007; US EPA, 2015a). The chemical additives alter the properties of the fluid (e.g., pH, viscosity) to enhance its performance (GWPC and ALL Consulting, 2009; Gupta and Valkó, 2007).

[10] Study wells were selected from the following nine well operators: 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.

[11] The nine oil and gas service companies 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.

each study well. In September 2013 and August 2014, follow-up letters were sent to each of the well operators asking for information not found in the original submissions. Additional information provided by the well operators was added to the corresponding well file. Some of the data received were claimed as confidential business information under the Toxic Substances Control Act. The EPA worked with the well operators to summarize and present the data in this report in a way that protects their claims of confidentiality.[12]

Analyses presented in this report primarily used information from two of the five topic areas included in the information request: drilling and completion information, and hydraulic fracturing procedures and reports.[13] Data were extracted from various documents contained in the well files, including, but not limited to, post-frac reports and completion reports. The extracted data were recorded as found in the well files (i.e., without rounding) and organized in a database. The database was used to conduct analyses and develop the figures presented throughout this report. A description of the extracted data and how they were used is provided below.

3.1. Hydraulic Fracturing Characteristics

Information on hydraulic fracturing was generally identified from post-frac reports, completion reports, and wellbore diagrams. Post-frac reports were often provided to well operators by the hydraulic fracturing service company and generally contained information on specific stages, including dates, measured depths, and surface treating pressures. When present in the well files, post-frac reports were usually the preferred source of information on hydraulic fracturing operations.

Hydraulic fracturing stage data were recorded for each study well. These data included the date hydraulic fracturing started for that stage, the measured depths of the top and bottom of the interval hydraulically fractured, the maximum surface treating pressure associated with the stage, and whether a temporary frac string was used. Different specific depth intervals were counted as unique hydraulic fracturing stages, regardless of the start date of hydraulic fracturing. If the same depth interval was hydraulically fractured on two or more different start dates, each was considered a unique stage.

Hydraulic Fracturing Jobs. Dates associated with the start of unique hydraulic fracturing stages were used to define separate hydraulic fracturing jobs that occurred in the same study well. For this report, a single hydraulic fracturing job consisted of one or more stages in which the time between consecutive stages was less than or equal to 90 days. The 90 day cut-off was selected after reviewing the number of days between consecutive stages reported for all of the study wells. This cut-off resulted in 414 separate hydraulic fracturing jobs among the 323 study wells. A 60 day cut-

[12] Non-confidential business information provided by the well operators is located in Federal Docket ID EPA-HQ-ORD-2010-0674 at www.regulations.gov.

[13] Information related to geologic maps and cross sections, as well as drilling and completion, was summarized in US EPA (2015b). Information collected about environmental releases was reported in US EPA (2015c). Although information in some well files was of good quality, the well files generally contained insufficient or inconsistent information on nearby surface and ground water quality, injected water volumes, and wastewater volumes and disposition; therefore, these data were not summarized.

off would have resulted in 416 hydraulic fracturing jobs, and a 120 day cut-off would have resulted in 413 jobs.

Hydraulic fracturing jobs were categorized as initial fracture treatments, re-completions, or re-fractures, depending on the timing and depth interval over which the hydraulic fracturing job was conducted. For this report, initial fracture treatments were defined as the first reported hydraulic fracturing job conducted at a well, regardless of the depth interval at which hydraulic fracturing occurred. A re-completion was defined as a job in which no portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job. Under this definition, a re-completion can include hydraulic fracturing of previously un-fractured portions of a well within the same geologic formation and hydraulic fracturing of previously un-fractured portions of a well within a different geologic formation. A re-fracture was defined as a job in which any portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job.

Temporary Frac Strings. If a temporary frac string was used for any stage of a multi-stage hydraulic fracturing job, the entire job was considered to have used a temporary frac string.

Measured Depth of the Point of Shallowest Hydraulic Fracturing. The measured depth of the point of shallowest hydraulic fracturing was identified for each study well, regardless of the number of hydraulic fracturing jobs. In cemented casing completions, the point of shallowest hydraulic fracturing was equal to the shallowest measured depth of a production perforation used for hydraulic fracturing. In formation packer 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 shallowest measured depth where hydraulic fracturing occurred.

Measured Depth of the Point of Deepest Hydraulic Fracturing. The measured depth of the point of deepest hydraulic fracturing was also identified for each study well, regardless of the number of hydraulic fracturing jobs. In cemented casing completions, this point was equal to the measured depth of the deepest perforation used for hydraulic fracturing. In formation packer completions, the measured depth of the point of deepest hydraulic fracturing was equal to the measured depth of the deepest formation packer used to isolate a hydraulic fracturing interval. In open hole completions, the measured depth of the point of deepest hydraulic fracturing was equal to the total measured depth of the well or, if a temporary frac string was used, the deepest measured depth where hydraulic fracturing occurred.

3.2. Monitoring and Testing Activities

Well files were reviewed for four types of monitoring and testing activities: casing pressure tests, surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring. These activities were included in this study, because they provide information on the mechanical integrity of the well, fracture growth, and the potential intersection of induced fractures with existing pathways (Section 5.3).

Casing Pressure Tests. Driller's reports and completion reports were reviewed for casing pressure tests conducted on production casing or temporary frac strings. For this study, a casing pressure test was defined as any surface pressure applied and held to a portion or all of the casing string used for hydraulic fracturing (i.e., the production casing or a temporary frac string, if used). The date and the maximum applied pressure were recorded for each casing pressure test identified.

Surface Treating Pressure Monitoring. Surface treating pressure monitoring was assumed to have occurred if a maximum treating pressure was recorded for any stage within a hydraulic fracturing job. Surface treating pressures were often reported in post-frac reports, but were also occasionally reported on wellbore diagrams or in completion reports or driller's reports. The available data often included a single surface treating pressure value; this value was identified as the maximum treating pressure. If multiple surface treating pressures were reported within a job, the largest was identified as the maximum treating pressure for that job.

Annular Pressure Monitoring. Annular pressure (also referred to as casing pressure) monitoring during hydraulic fracturing was often identified from post-frac reports. If annular pressure monitoring was identified for any stage of a multi-stage hydraulic fracturing job, the entire job was considered to have been monitored. The available data were frequently insufficient to analyze changes in the annular pressure. In all cases, the monitored annulus was assumed to be the annular space directly behind the casing string used for hydraulic fracturing, even when more than one annulus could have been monitored.

Microseismic Monitoring. If microseismic monitoring was reported for any stage of a multi-stage hydraulic fracturing job, the entire job was considered to have been monitored. Microseismic monitoring reports included maps or graphs of microseismic events that were recorded during specific hydraulic fracturing stages. In many cases, microseismic monitoring reports also included a summary of microseismic monitoring results for each monitored stage (e.g., fracture dimensions and direction). The available data were used to estimate the maximum lateral and vertical components of fracture growth for each microseismically monitored stage.[14] If multiple stages within a single hydraulic fracturing job were microseismically monitored, the largest lateral and vertical components of fracture growth among the monitored stages were identified as the maximum lateral and vertical components of fracture growth for the entire job.

For this report, the maximum lateral component of fracture growth was defined as the maximum reported distance between the point of hydraulic fracturing in the well and the microseismic event located furthest away from the well in the *x-y* plane. The maximum vertical component of fracture growth was defined as the maximum reported distance between the point of hydraulic fracturing in the well and the shallowest microseismic event (i.e., maximum upward vertical fracture growth). If the reported vertical component of fracture growth could not be discerned into distance upward and downward from the point of hydraulic fracturing, the maximum vertical component of fracture

[14] As discussed in Section 5.3, microseismic monitoring is not a direct measurement of fracture growth. Microseismic monitoring detects microseismic events caused by changes in stress and fluid pressure in the subsurface (Fisher and Warpinski, 2012). These events are assumed to be indicative of fracture growth during hydraulic fracturing (Davies et al., 2012; Fisher and Warpinski, 2012; Flewelling et al., 2013).

growth was set equal to the entire reported vertical component. This approach was used, because it estimated the shortest possible distance between induced fractures and protected ground water resources. Because fractures often grow up and down, this approach likely overestimated the upward vertical component of fracture growth (Fisher and Warpinski, 2012).

3.3. Well Design and Construction Characteristics

Some analyses presented in Section 4 compared data described in Sections 3.1 and 3.2 to data originally described in US EPA (2015b), including the presence of casing and cement and the depths of protected ground water resources. Methods used to identify these data elements are summarized below, and additional detail is available in US EPA (2015b).

Casing and Cement. 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 placement behind surface, intermediate, and production casing was determined from various sources, including cement evaluation logs, 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.

Protected Ground Water Resources. 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, this report does not use a single definition of "protected ground water resource" and relies solely on information provided to the EPA by well operators in response to the Agency's request for the depth of the base, or bottom, of the protected ground water resource at each study well. Data sources used by well operators to report depths of protected ground water resources are described in detail in US EPA (2015b). In general, data presented in Table 5 of US EPA (2015b) show that depths of protected ground water resources were provided by well operators for nearly all of the study wells. 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 approved permit applications). The base of the protected ground water resource was reported for most study wells.

3.4. Estimates of Hydraulic Fracturing Characteristics and Monitoring and Testing Activities

The 323 study wells are statistically representative of the wells reported to the EPA by the nine hydraulic fracturing service companies (US EPA, 2015b). As shown in Figure 2, the study wells also reflect the geographic distribution of the wells reported by the nine service companies.

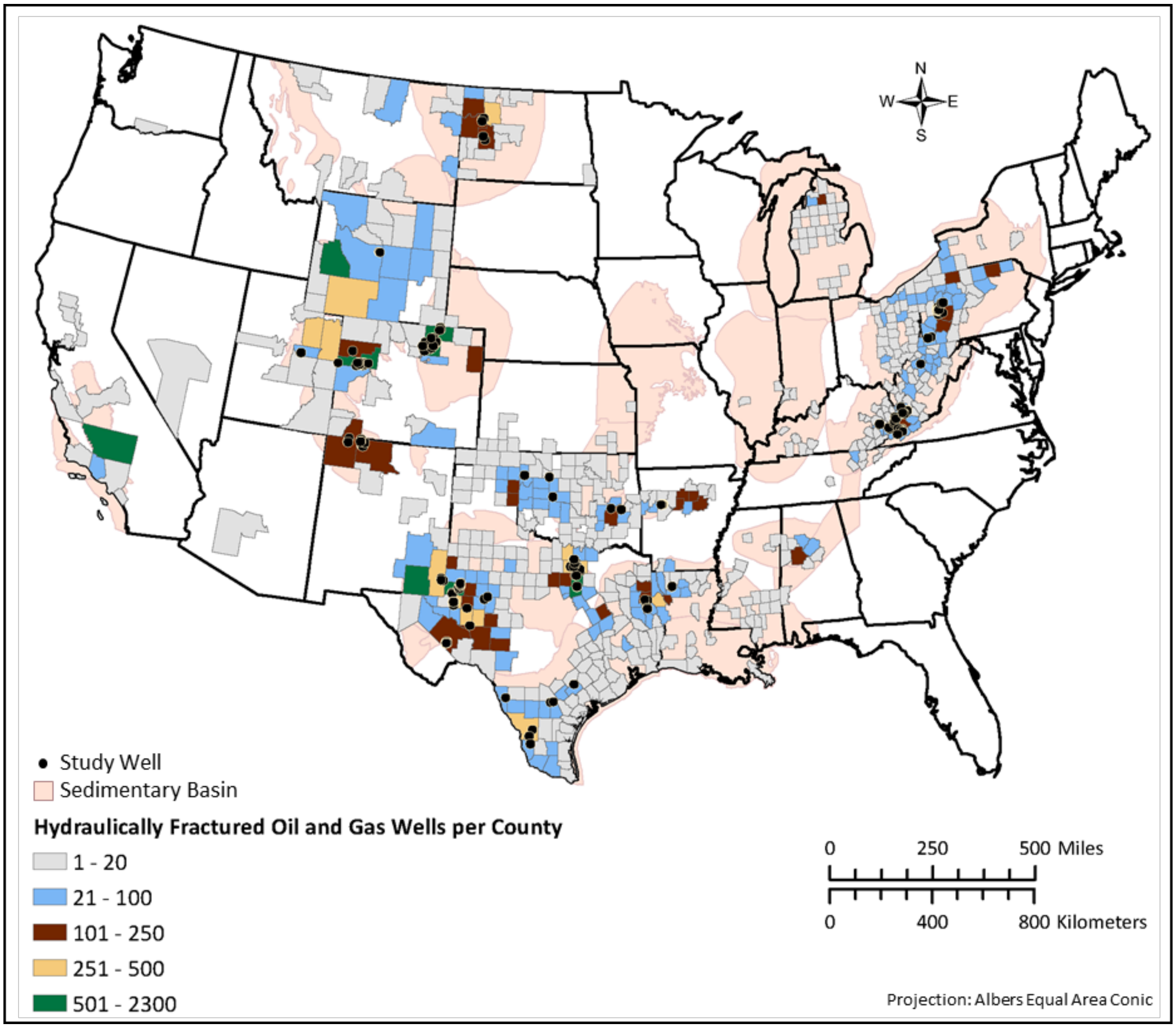

Figure 2. Locations of the 323 study wells. The study wells were selected from a list of wells that were reported by nine oil and gas service companies to have been hydraulically fractured between approximately September 2009 and September 2010. The number of wells reported by the service companies are shown at the county-level for comparison. Fewer than 20 well identifiers were reported in Alaska, and none were among the 323 study wells. (US EPA, 2015b)

Because the study wells are statistically representative of the wells reported by the nine hydraulic fracturing service companies, results from analyses conducted on the 323 study wells were extrapolated to the sampled population (i.e., the wells reported by the nine hydraulic fracturing service companies). To conduct the extrapolation, each of the 323 study wells was assigned to a category (or characteristic) defined by a given analysis. Statistical weights, which ranged from 4 to

190, 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. Point estimates and confidence intervals are presented at the national level and are statistically representative of the oil and gas production wells hydraulically fractured by the nine service companies. Any characteristics not identified by the study wells are not represented in this report. (US EPA, 2015b)

Some analyses identified rare characteristics (e.g., near zero percent of the wells) or focused on subsets of the population of all wells (e.g., among hydraulic fracturing jobs with casing pressure tests). For some of these analyses, the set of study wells examined were found in only a few of the nine sampled well operators or the confidence intervals were unrealistically narrow. As a result, the approach for calculating confidence intervals was adjusted to improve the accuracy of the confidence intervals (Appendix).

3.5. 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 well operators in response to the information request. Quality assurance and quality control measures were used to ensure that data were of sufficient quality for analysis and that the analyses performed were conducted properly. Three separate measures were employed to assess the data used to describe hydraulic fracturing characteristics and monitoring and testing activities: logical tests of the data in the database, re-review of at least 10 percent of the extracted data, and well operator review of the extracted data. Together, these measures assure the quality of the data used in the analyses presented in this report.

Logical Tests of the Data in the Database. Following the initial extraction of data from the well files, database queries were used to identify logical inaccuracies or inconsistencies and missing data. The queries included, but were not limited to, searches for blank entries, text entries that should have been numeric, shallower depths incorrectly occurring below deeper depths, and dates for earlier events occurring after later events. Inconsistencies identified from these queries were corrected in the database after reviewing the original information provided by the well operators.

Re-review of the Extracted Data. At least 10 percent of the well files from each well operator were re-reviewed by a different person for the data elements used in this report.[15] The re-review was used to assess the repeatability of the data extraction. For most data elements, there was good agreement between the original data extracted and the data extracted during the re-review (less than or equal to 10 percent difference), and no changes were made to the database.

There was initially poor agreement between the original data extracted from the well files and data extracted during the re-review for two data elements: dates and test pressures associated with

[15] One hundred percent of microseismic monitoring reports were re-reviewed simultaneously by two reviewers, because the data provided often needed more interpretation than other data elements used for the analyses presented in this report. The reviewers discussed the applicability and accuracy of data reported for each microseismically monitored hydraulic fracturing job before determining the maximum vertical and lateral components of fracture growth (Section 3.2). This process provided a more consistent data extraction effort for the microseismic monitoring data and a higher degree of accuracy in the resulting dataset.

casing pressure tests and maximum treating pressures. The poor agreement occurred, because individual hydraulic fracturing jobs were not defined prior to the original data extraction, which resulted in both missing data and incorrectly assigned data for study wells with more than one hydraulic fracturing job. Once individual hydraulic fracturing jobs were identified (Section 3.1), data from study wells with more than one job were re-reviewed to correct entries for casing pressure tests and maximum treating pressures. This corrected issues of missing or incorrectly-assigned data for study wells with more than one hydraulic fracturing job.

Operator Review of the Extracted Data. Data extracted for each study well were shared with the respective well operator in August 2014, after the re-review of the extracted data. In total, 17,472 data elements were provided to the well operators for their review. Well operators identified changes to 1,598 data elements (less than 10 percent of the data elements provided to the well operators). The majority of these changes (1,171 data elements) described the use of annulus pressure monitoring as standard operating procedures for hydraulic fracturing operations, the documentation of which was not always recorded in the well files. Well operators also identified changes to 247 data elements related to hydraulic fracturing stages, 80 data elements related to casing pressure tests, 53 data elements related to maximum treating pressures, and 47 data elements related to the use of temporary frac strings. All updates provided by the operators were incorporated.

This work was conducted following the methods and procedures contained in the project-related quality assurance project plans (The Cadmus Group, 2013; US EPA, 2013, 2014; 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

The results presented below represent an estimated 23,200 (95 percent confidence interval: 21,400-25,000) onshore oil and gas production wells that were reported by nine oil and gas service companies to have been hydraulically fractured between approximately September 2009 and September 2010. Results are presented as rounded estimates and, where appropriate, 95 percent confidence intervals.

As described in US EPA (2015b), the wells were predominantly vertical wells drilled between 2000 and 2010, but also included other well orientations (i.e., horizontal and deviated) and wells drilled prior to 2000.[16] 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. Eighty-seven (68-96) percent of the wells had cemented casing completions, while 6 (4-11) percent had formation packer completions and another 6 (1-33) percent had open hole completions; Figure 1 illustrates the different well completion types.

[16] An estimated 65 (48-80) percent of the wells were vertical, 24 (11-44) percent were deviated, and 11 (7-16) percent were horizontal.

4.1. Hydraulic Fracturing Characteristics

One hydraulic fracturing job was identified for 84 (67-94) percent of the 23,200 (21,400-25,000) wells represented in this study, and two or more hydraulic fracturing jobs were identified for 16 (6-33) percent of the wells. Because some wells had more than one hydraulic fracturing job, there were an estimated 28,500 (25,100-31,900) hydraulic fracturing jobs conducted at the wells represented in this study, and job dates ranged from 1961 to 2011.[17] The majority of the jobs [71 (60-80) percent] were conducted between September 30, 2009, and September 30, 2010.[18]

The number of jobs per well ranged from one to more than four (Figure 3). For those wells hydraulically fractured more than once, the time between hydraulic fracturing jobs at a single well ranged from approximately three months to 25 years. The median time between hydraulic fracturing jobs at a single well was nearly four years.

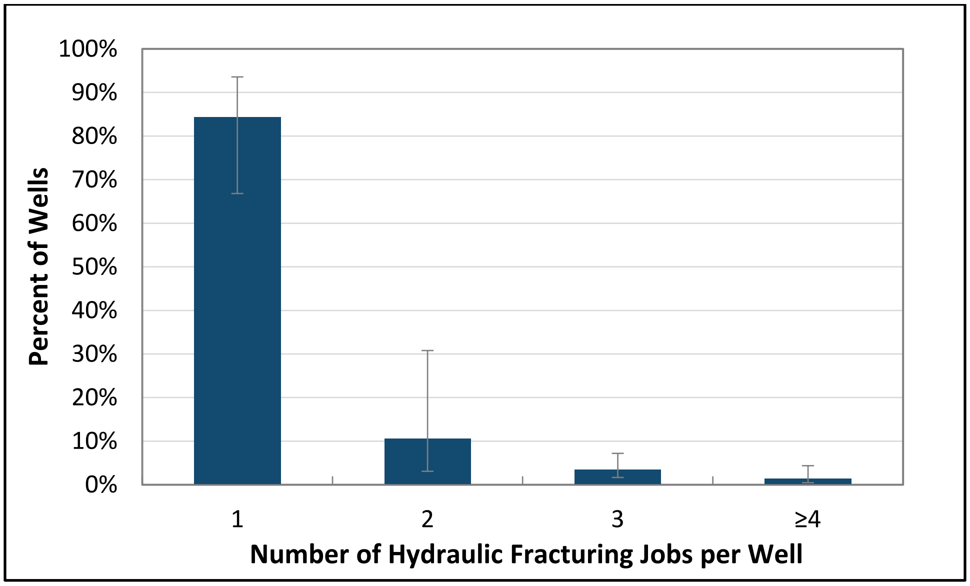

Figure 3. Number of hydraulic fracturing jobs conducted per well at the oil and gas production wells represented in this study. For this report, a single hydraulic fracturing job consisted of one or more stages in which the time between consecutive stages was less than or equal to 90 days. Error bars display 95 percent confidence intervals.

Of the 28,500 (25,100-31,900) hydraulic fracturing jobs, 81 (71-89) percent were initial fracture treatments, 11 (5-23) percent were re-completions, and 8 (5-12) percent were re-fractures (Figure 4). As noted in Section 3.1, re-completions were defined as a job in which no portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured during a previous job. In 95 (75-99) percent of the re-completions, hydraulic fracturing occurred at shallower depths than the previous job. In 6 (1-25) percent of the re-completions, hydraulic

17 References to oldest, longest, 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 23,200 wells in the sampled population. For example, 1961 is the year when the oldest hydraulic fracturing job from among the 323 study wells was conducted, but there are likely older jobs in the population of 23,200 oil and gas production wells reported by the nine service companies.

18 An estimated 7,100 (2,900-11,300) jobs occurred before September 30, 2009, and 1,200 (700-1,800) jobs occurred after September 30, 2010.

fracturing occurred at deeper depths than the previous job. Among all re-completions, the measured distance between the points of shallowest hydraulic fracturing in the re-completion and the previous job ranged from 2,400 feet below the point of shallowest hydraulic fracturing in the previous job to 4,630 feet above the point of shallowest hydraulic fracturing in the previous job. The median distance between the points of shallowest hydraulic fracturing in the re-completion and the previous job was 1,060 feet above the point of shallowest hydraulic fracturing in the previous job. The median time between a given fracture job and a re-completion was two years (range of three months to 25 years). The median time between a given fracture job and a re-fracture, defined as a hydraulic fracturing job in which any portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job, was six years (range of nine months to 21 years).

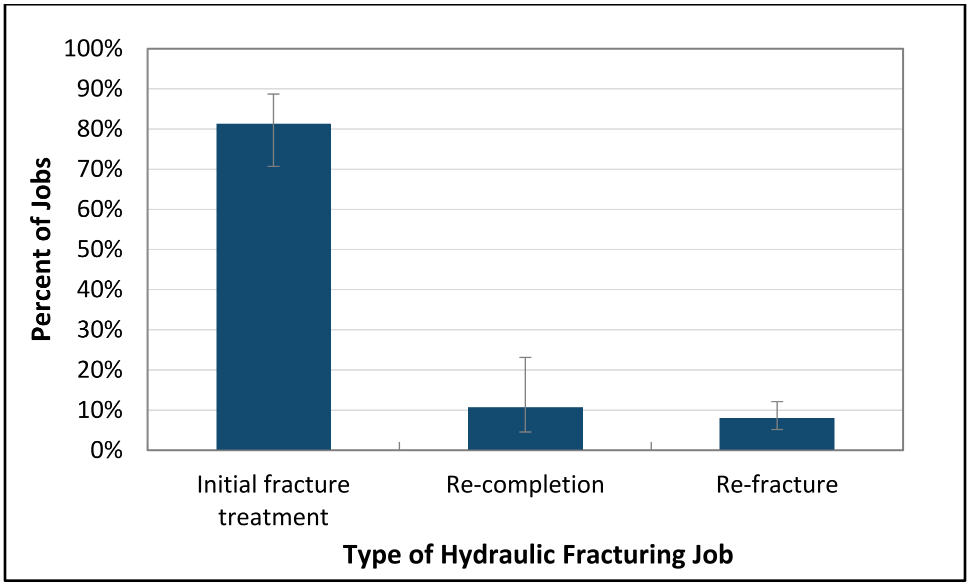

Figure 4. Types of hydraulic fracturing jobs conducted at the oil and gas production wells represented in this study. For this report, initial fracture treatments were defined as the first reported hydraulic fracturing job conducted at a well, regardless of the depth interval at which hydraulic fracturing occurred. A re-completion was defined as a job in which no portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job. A re-fracture was defined as a job in which any portion of the depth interval at which hydraulic fracturing was conducted overlapped with a depth interval fractured in a previous job. Error bars display 95 percent confidence intervals.

The hydraulic fracturing jobs varied in duration and number of stages (Figure 5). Job durations ranged from less than one day to more than 50 days, with nearly two-thirds of the jobs [65 (51-77) percent] conducted in one day (panel a). The number of stages within a single hydraulic fracturing job ranged from one to more than 13 (panel b).

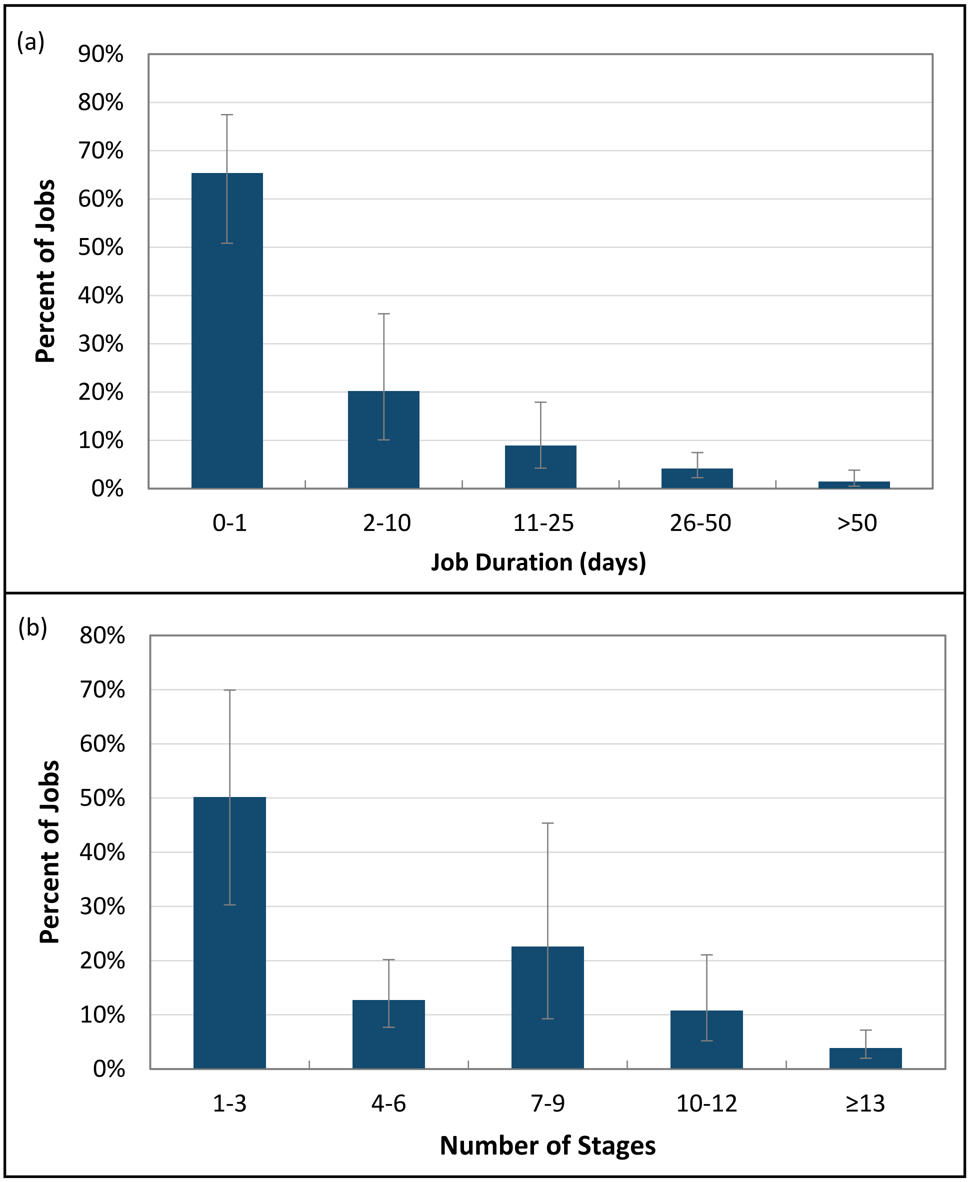

Figure 5. (a) Job duration. (b) Number of stages per hydraulic fracturing job. For this report, a hydraulic fracturing stage refers to a specific measured depth interval for which hydraulic fracturing began on a specific date. Error bars display 95 percent confidence intervals.

4.1.1. Hydraulic Fracturing and Well Construction

Hydraulic fracturing depths and job start dates were compared to well design and construction characteristics to describe the spatial and temporal relationship of hydraulic fracturing to the well's construction, including the presence and age of the casing and cement and the proportion of the measured length of the well that was hydraulically fractured.

Casing and Cement. Casing and cement are the primary components of oil and gas production wells. Casing is installed during well construction to isolate hydrocarbon production from the surrounding geology. After the casing is lowered in the drilled hole, cement is often placed between the outside of the casing and the inside of the drilled hole (i.e., the wellbore) or an existing outer casing to seal off this annular space (Baker, 1979; Smith, 1976). The cement also provides support behind the casing and protects it from corrosive fluids in the subsurface (Baker, 1979; Smith, 1976).

Ninety (73-96) percent of the 28,500 (25,100-31,900) hydraulic fracturing jobs occurred in wells with cemented casing completions, 5 (3-9) percent occurred in wells with formation packer completions, and 5 (1-28) percent occurred in wells with open hole completions. Ten (3-30) percent of the hydraulic fracturing jobs were conducted using a temporary frac string for one or more stages of the job. Temporary frac strings were used in wells with production casing and wells with open holes.

Figure 6 displays the measured length of the cement sheath behind the production casing above the point of shallowest hydraulic fracturing. Thirteen (5-32) percent of the wells had uncemented production casing directly above the point of shallowest hydraulic fracturing; these wells were often open hole or formation packer completions.

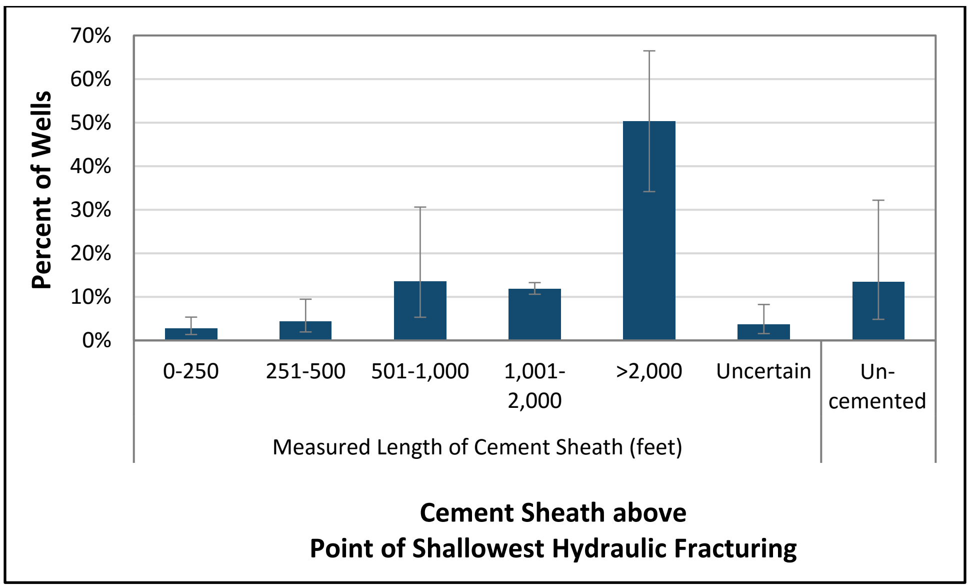

Figure 6. Measured length of the cement sheath behind the production casing above the point of shallowest hydraulic fracturing. "Uncemented" includes wells that did not have cement behind the production casing directly above the point of shallowest hydraulic fracturing; these wells were often open hole or formation packer completions. Information in the well files was insufficient to determine the top of cement for some wells; this is reflected by the "uncertain" category. Error bars display 95 percent confidence intervals.

As shown in Figure 6, the most commonly reported measured length of the cement sheath above the point of shallowest hydraulic fracturing was greater than 2,000 feet.[19] Thirty-three (20-49) percent of the wells had a cement sheath that was 2,000 feet or less, and 21 (10-39) percent had a cement sheath that was 1,000 feet or less. The measured length of the cement sheath could not be

[19] The measured length of the cement sheath above the point of shallowest hydraulic fracturing ranged from 90 feet to 9,750 feet. The median measured length of the cement sheath above the point of shallowest hydraulic fracturing was 2,550 feet.

determined for 4 (2-8) percent of the wells, because cement top information behind the production casing was unavailable.

The age of well components (i.e., casing, cement, and packers) at the time of hydraulic fracturing was estimated by calculating the time between the start date of the hydraulic fracturing job and the spud date of the well (Figure 7). This approach assumes that casing, cement, and packers present at the time of hydraulic fracturing were installed when the well was constructed and were not replaced over the lifetime of the well. Hydraulic fracturing jobs conducted using temporary frac strings were identified in a separate category in Figure 7, because temporary frac strings are not permanent well components. Temporary frac strings are placed in the well before hydraulic fracturing and removed when hydraulic fracturing is complete.

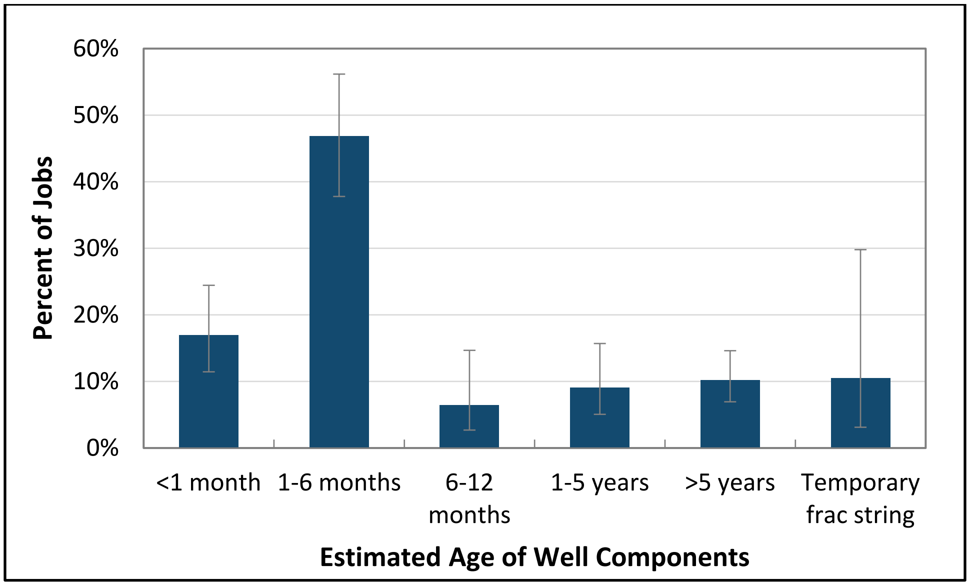

Figure 7. Estimated age of well components (e.g., casing, cement, and packers) at the beginning of the hydraulic fracturing job. Well component age was estimated by calculating the time between the start date of the hydraulic fracturing job and the spud date of the well (i.e., the date drilling started). Hydraulic fracturing jobs conducted using temporary frac strings are identified in a separate category, because temporary frac strings are not permanent well components. Temporary frac strings are placed in the well prior to hydraulic fracturing and removed when hydraulic fracturing is complete. Error bars display 95 percent confidence intervals.

As shown in Figure 7, nearly two-thirds of the hydraulic fracturing jobs [64 (48-77) percent] were conducted within six months of the spud date. The estimated age of well components at the time of an initial fracture treatment ranged from eight days to nearly 51 years, with a median of 45 days. The estimated age of well components at the time of a re-fracture or re-completion ranged from nearly six months to approximately 26 years, with a median of six years.

Hydraulically Fractured Well Lengths. Hydraulically fractured well lengths ranged from less than 1,000 feet to greater than 5,000 feet per hydraulic fracturing job. Ninety-five (87-98) percent of the wells had 50 percent or less of the total measured length of the well hydraulically fractured (Figure 8). The percentages shown on the *x*-axis in Figure 8 were calculated by subtracting the measured depth of the point of shallowest hydraulic fracturing in the well from the measured depth of the point of deepest hydraulic fracturing in the well and dividing this difference by the total measured depth of the well (Section 3.1). This approach likely overestimated the length of the well that was hydraulically fractured, because the entire length between the points of shallowest and deepest hydraulic fracturing may not have been hydraulically fractured. For example, wells completed in more than one targeted geologic zone were not hydraulically fractured in the intervening non-targeted geologic zones.

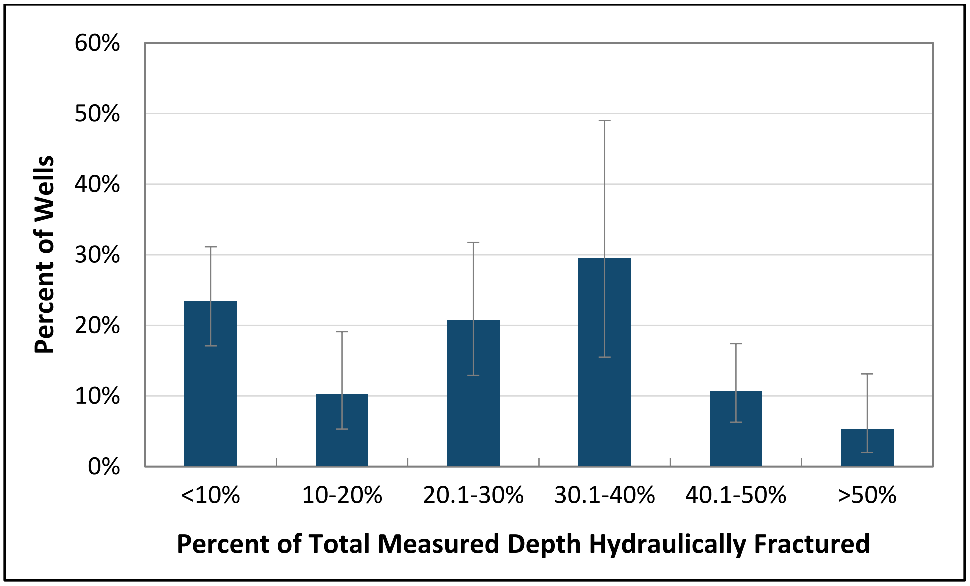

Figure 8. Percent of the total measured depth that was hydraulically fractured in the oil and gas production wells represented in this study. Percentages were calculated by subtracting the measured depth of the point of shallowest hydraulic fracturing in the well from the measured depth of the point of deepest hydraulic fracturing in the well and dividing this difference by the total measured length of the well. This approach likely overestimates the length of the well that was hydraulically fractured, because the entire length between the points of shallowest and deepest hydraulic fracturing may not have been hydraulically fractured. Error bars display 95 percent confidence intervals.

4.2. Monitoring and Testing Activities

As described in Section 3.2, well files were reviewed for four types of monitoring and testing activities: casing pressure tests, surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring. Two or more of these monitoring and testing activities were reported for 76 (62-86) percent of the hydraulic fracturing jobs, with all four types of monitoring reported for 0.08 (0.004-2) percent of jobs (Figure 9). None of the monitoring or testing activities considered in this study were reported for 2 (1-5) percent of the hydraulic fracturing jobs. Information in the well files was sometimes insufficient to conclusively determine whether a given monitoring or testing activity occurred. Therefore, the reported occurrence of monitoring and testing activities may be underestimates of the actual occurrence of the monitoring or testing activities considered in this study. Similarly, the lack of reported monitoring or testing activities may be an overestimate.

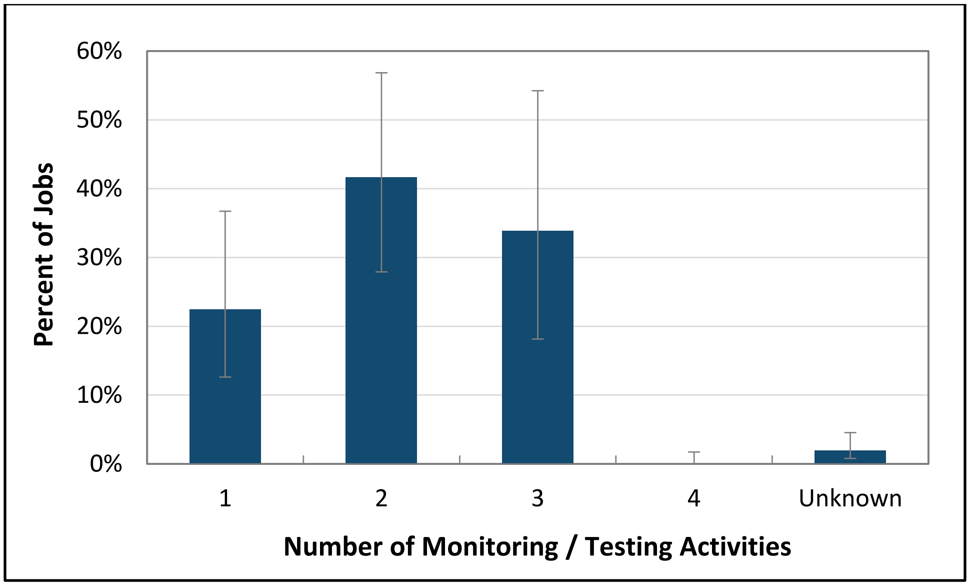

Figure 9. Reported occurrence of the number of different types of monitoring and testing activities conducted per hydraulic fracturing job. Four types of monitoring and testing activities were considered: casing pressure tests, surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring. "Unknown" refers to hydraulic fracturing jobs for which no evidence of any of the four types of monitoring and testing activities was found in the well files. Because information in the well files was sometimes insufficient to conclusively determine whether a monitoring and testing activity occurred, the first four categories (1-4) may be underestimates and the last category (unknown) may be an overestimate. Error bars display 95 percent confidence intervals.

As shown in Figure 9, the use of two different types of monitoring and testing activities was most commonly reported among all of the hydraulic fracturing jobs [42 (28-57) percent of jobs]. Among the jobs with two different types of monitoring and testing activities reported, the most commonly identified combination was a casing pressure test and surface treating pressure monitoring.

Figure 10 displays the reported occurrence of each of the four types of monitoring or testing activities among the hydraulic fracturing jobs represented in this study. Surface treating pressure monitoring, as determined by the identification of maximum treating pressures, was reported to have occurred in 97 (94-99) percent of the hydraulic fracturing jobs. In contrast, microseismic monitoring was reported to have been conducted for 0.5 (0.1-2) percent of the hydraulic fracturing jobs. Annular pressure monitoring was reported to have occurred in 53 (27-77) percent of the jobs, and activities considered to be casing pressure tests for the purposes of this study (Section 3.2) were reported to have occurred in 57 (44-70) percent of the jobs.

With the exception of annular pressure monitoring, analyses using data from the monitoring and testing activities considered in this study are presented below. As noted in Section 3.2, the available data from annular pressure monitoring were frequently insufficient to analyze changes in annular pressure. Therefore, no further analyses of annular pressure monitoring data were performed.

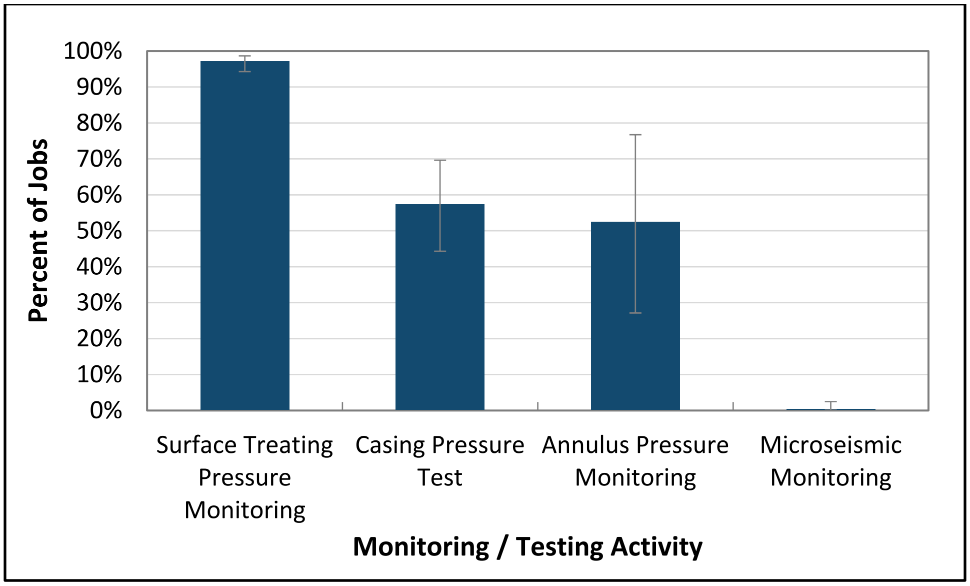

Figure 10. Reported occurrence of four types of monitoring and testing activities among the hydraulic fracturing jobs represented in this study. These may be underestimates of the occurrence of each type of monitoring or testing activity, because information in the well files was sometimes insufficient to conclusively determine whether the monitoring or testing activity occurred. Error bars display 95 percent confidence intervals.

4.2.1. Surface Treating Pressure Monitoring

Surface treating pressure monitoring provides information on the maximum pressure applied to wells during hydraulic fracturing. Among the hydraulic fracturing jobs conducted at these wells, maximum surface treating pressures ranged from less than 2,000 pounds per square inch (psi) to more than 9,000 psi, as shown in Figure 11. The median maximum treating pressure was 5,640 psi. Maximum treating pressures could not be determined for 3 (1-6) of the hydraulic fracturing jobs due to insufficient data in the well files.

4.2.2. Casing Pressure Tests

Casing pressure tests can be conducted before hydraulic fracturing to assess the mechanical integrity of the well and to determine whether or not the well can withstand the pressures expected during hydraulic fracturing (US EPA, 2011b). Test pressures from casing pressure tests conducted in 2009 and 2010 were compared to maximum treating pressures recorded for hydraulic fracturing jobs that occurred in the same time frame. The two-year time frame was selected for this analysis, because the majority of the hydraulic fracturing jobs occurred during this time and because records were generally more complete for more recent hydraulic fracturing jobs.

Each casing pressure test was assigned to a hydraulic fracturing job that both occurred at the same well and was conducted closest in time after the date of the casing pressure test. A casing pressure test was assigned to multiple hydraulic fracturing jobs at a single well, if there were no additional casing pressure tests performed between hydraulic fracturing jobs. Of the 28,500 (25,100-31,900) hydraulic fracturing jobs represented in this study, 15,600 (11,800-19,300) jobs occurred in 2009 or 2010 and had an assigned casing pressure test that occurred before the hydraulic fracturing

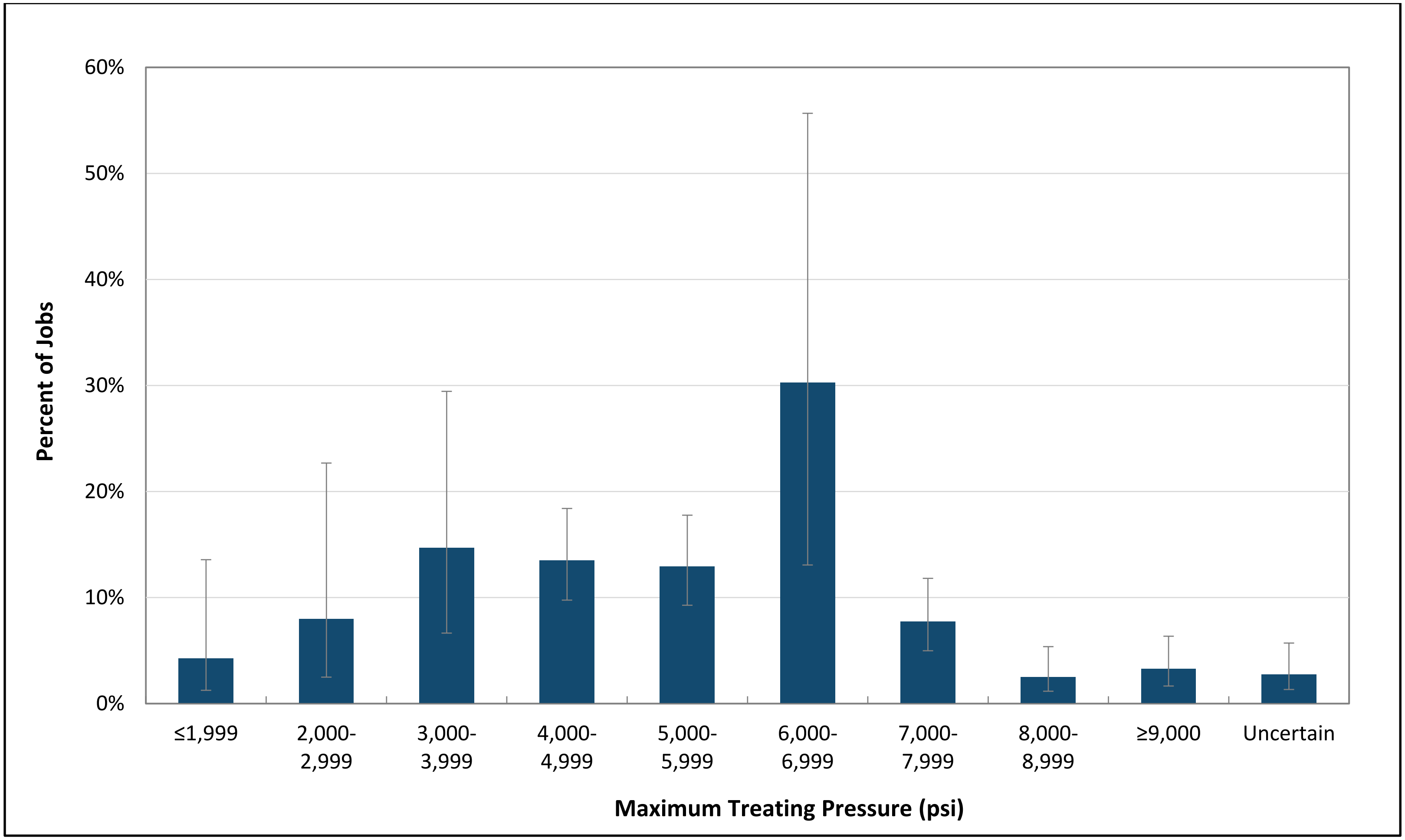

Figure 11. Maximum treating pressures applied during the hydraulic fracturing jobs conducted at the oil and gas production wells represented in this study. Information in the well files was insufficient to determine maximum treating pressures for some wells; this is reflected by the "uncertain" category. Error bars display 95 percent confidence intervals.

job.[20] In 52 (20-82) percent of these jobs, the casing test pressure was greater than or equal to the maximum treating pressure, and in 48 (18-80) percent, the casing test pressure was less than the maximum treating pressure. Figure 12 displays the magnitude of the difference between the casing test pressure and the maximum treating pressure for each of these categories.

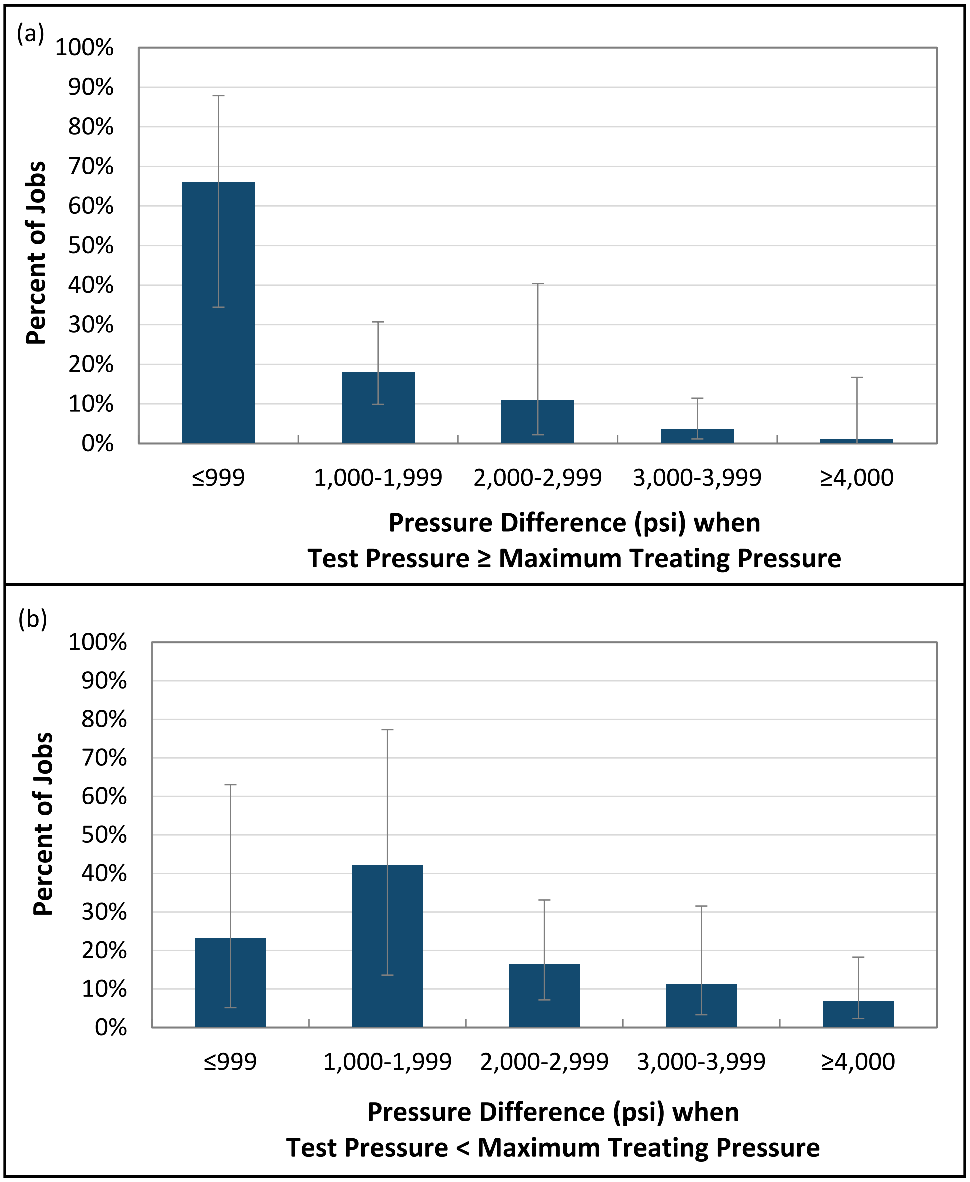

Figure 12. Magnitude of the difference between the casing test pressure and the maximum treating pressure when the casing test pressure was (a) greater than or equal to or (b) less than the maximum treating pressure. In all cases, the casing pressure test was conducted on the same well as the hydraulic fracturing job, and the casing pressure test occurred prior to the hydraulic fracturing job. An estimated 8,100 (4,000-12,200) jobs are represented in panel a, and 7,400 (4,200-10,700) jobs are represented in panel b. Error bars display 95 percent confidence intervals.

[20] The time between the assigned casing pressure test and the date of the hydraulic fracturing stage corresponding to the maximum treating pressure for the hydraulic fracturing job ranged from zero days to approximately two years.

As shown in Figure 12a, when the casing test pressure was greater than or equal to the maximum treating pressure, the most common difference between these pressures was found to be less than 1,000 psi. When the casing test pressure was less than the maximum treating pressure, the most common difference between the pressures was found to be between 1,000 and 1,999 psi (Figure 12b).

4.2.3. Microseismic Monitoring

While microseismic monitoring is not a direct measurement of fracture growth during hydraulic fracturing, data collected during microseismic monitoring are often considered to be indicative of fracture growth (Davies et al., 2012; Fisher and Warpinski, 2012; Flewelling et al., 2013). As described in Section 3.2, microseismic monitoring data provided for the study wells were used to estimate the maximum vertical and lateral components of fracture growth. Among the 100 (40-300) jobs in which microseismic monitoring was reported, the maximum vertical component of fracture growth (i.e., fracture height) per job ranged from 380 feet to 1,340 feet, with a median value of 680 feet. The maximum lateral component of fracture growth per job ranged from 700 feet to 2,250 feet, with a median value of 1,000 feet.

Maximum fracture heights estimated from microseismic monitoring data were compared to cement sheath heights directly above the point of shallowest hydraulic fracturing to estimate whether induced fractures extended above the top of the cement. The comparison was done for individual hydraulic fracturing jobs. Among the 100 (40-300) hydraulic fracturing jobs that reported microseismic monitoring, the true vertical depth of the top of the cement sheath behind the production casing in the well was always shallower than the true vertical depth of the top of the maximum fracture height estimated from microseismic monitoring data. Fractures created during these hydraulic fracturing jobs were therefore unlikely to extend beyond the cement sheath directly above the point of shallowest hydraulic fracturing. Due to the small number of hydraulic fracturing jobs in which this analysis was possible, this observation should not be interpreted to be reflective of all of the wells represented in this study.

Maximum fracture heights were also compared to the depths of operator-reported protected ground water resources to assess whether induced fractures could have extended directly through the geologic strata to protected ground water resources reported by well operators. Again, the comparisons were done for individual hydraulic fracturing jobs. Given the assumptions identified in Sections 3.2 and 3.3, induced fractures were estimated to have grown no closer than 5,000 feet below operator-reported protected ground water resources during the jobs for which this distance could be calculated. Fractures created during these hydraulic fracturing jobs were therefore unlikely to have reached the protected ground water resources reported by well operators. Because of the small number of wells for which this analysis was possible, this observation should not be interpreted to be reflective of all of the wells represented in this study.

5. Discussion of Subsurface Fluid Movement During Hydraulic Fracturing

During hydraulic fracturing in an oil or gas well, hydraulic fracturing fluids are injected down the well under pressures great enough to fracture the targeted rock formation. The applied pressure moves the hydraulic fracturing fluid through the well and into the targeted rock formation. Once in the rock, the pressurized hydraulic fracturing fluid creates and grows fractures in the subsurface. Hydraulic fracturing fluid travels through the subsurface via the newly-created fractures, interconnected pore spaces within the rock, or other permeable pathways (e.g., faults, natural fracture systems, or nearby wells) (King, 2014; Ross and King, 2007). The pressurized hydraulic fracturing fluid can also displace fluids naturally present in the subsurface (e.g., brine, methane, or other hydrocarbons), causing these fluids to move through the subsurface during hydraulic fracturing (Brownlow et al., 2016).

The potential for hydraulic fracturing fluids, or fluids naturally present in the subsurface, to move to underground drinking water resources during hydraulic fracturing depends on many factors. In general, these factors include, but are not limited to, the design and construction of the hydraulically fractured production well, the design and execution of the hydraulic fracturing job, the characteristics of subsurface rock formations, and the relative location of induced fractures to underground drinking water resources or existing permeable pathways that may lead to drinking water resources (Fisher and Warpinski, 2012; Stringfellow et al., 2015; US EPA, 2015b). Together, these factors affect how fluids move through the subsurface during hydraulic fracturing and whether they can reach underground drinking water resources.

Data presented in Section 4, and other information included in the wells files, are used below to explore the role of the following, specific factors in subsurface fluid movement during hydraulic fracturing at the oil and gas production wells represented in this study:

(1) the mechanical integrity of the hydraulically fractured oil or gas production well, and
(2) the potential intersection of newly-created fractures with underground drinking water resources or nearby existing pathways.

The above factors are the focus of the discussion below. Data relevant to the design and construction of hydraulically fractured production wells were summarized and presented in US EPA (2015b).

5.1. Mechanical Integrity

A well has mechanical integrity when it contains fluids within the well and prevents fluid movement along the outside of the well, between the outermost casing and the wellbore wall (GWPC, 2014). Mechanical integrity is achieved through well design and construction, which can include the presence of multiple barriers (e.g., casing and cement), and is retained through well maintenance (GWPC, 2014; King and King, 2013; Ross and King, 2007).

The mechanical integrity of a well depends on the mechanical integrity of the individual components of the well. During hydraulic fracturing, pressure is applied to the inside of the production casing or a temporary frac string, if used. When these well components have mechanical integrity, the hydraulic fracturing fluid remains in the production casing or the temporary frac string and reaches the targeted geologic formation without moving into the annular space behind the production casing or the temporary frac string. When the well components used for hydraulic fracturing do not have mechanical integrity or lose mechanical integrity during hydraulic fracturing, fluids can move outside of the production casing or the temporary frac string into one or more of the annular spaces in the well. If multiple casings and cement sheaths are present within a well, they can block fluid movement into the surrounding environment by serving as additional barriers between the invaded annular space and the surrounding geology. A well integrity failure occurs when no barriers (e.g., casing and cement) are left to block fluid from entering the surrounding environment (King and King, 2013).

Downhole well component failures during hydraulic fracturing were reported by well operators in 3 (1-8) percent of the hydraulic fracturing jobs represented in this study. For some hydraulic fracturing jobs, these events were reported using phrases such as "communication to surface" or "casing leak." For other jobs, these events were inferred from information available in the well files. For example, "came around" and "annular pressure increase" were interpreted as well component failures during hydraulic fracturing when written descriptions of the well's status and well operations indicated a well component failure. In all of these cases, information in the well files suggested that hydraulic fracturing fluid flowed from the inside of the casing string used for hydraulic fracturing to one or more of the annular spaces behind the casing string.

When well component failures were reported, well operators generally stopped the hydraulic fracturing job, addressed the cause of the failure, and completed the job. There were often multiple barriers (e.g., casing and cement) between the well components that failed and operator-reported protected ground water resources.[21,22] As noted above, multiple casings and cement sheaths can block fluid movement into the surrounding environment by serving as additional barriers between the invaded annular space and the surrounding geology. There was no evidence in the well files to suggest that these additional barriers failed. However, there were well component failures in which there were no additional barriers between the casing string used for hydraulic fracturing and the operator-reported protected ground water resource (i.e., a well integrity failure). Well integrity failures were reported in 0.5 (0.1-2) percent of all of the hydraulic fracturing jobs. Information in the well files suggested that, in these cases, hydraulic fracturing fluid entered the annular space between the casing string used for hydraulic fracturing and the surrounding geology at depths corresponding to the operator-reported protected ground water resource. Based on the

[21] An estimated 800 (10-1,800) hydraulic fracturing jobs reported a well component failure. Of these jobs, an estimated 700 (10-1,600) had one or more additional barriers between the invaded annular space and the operator-reported protected ground water resource.

[22] As described in US EPA (2015b), the wells represented in this study 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. The most common number of barriers to potential subsurface fluid movement from the 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), with a range from zero to six. Additionally, there were often two or more barriers (i.e., cemented casings) to potential subsurface fluid movement along the outside of the well, from the targeted rock formation to operator-reported protected ground water resources, with a range from zero to four. A detailed discussion of these pathways, and the presence or absence of barriers, can be found in Section 5 of US EPA (2015b).

information contained in the well files, it was not possible to determine whether fluid moved from the annular space into protected ground water resources in these cases.

The well component failures reported in 3 (1-8) percent of the hydraulic fracturing jobs occurred during initial fracture treatments, re-completions and re-fractures, and in jobs conducted using a temporary frac string. When compared to the larger population of hydraulic fracturing jobs, a greater proportion of jobs conducted using a temporary frac string reported a well component failure [20 (7-46) percent] than jobs that did not use a temporary frac string [0.9 (0.2-3) percent]. As described in Section 2, a temporary frac string is lowered into the well and secured at its base using a packer or by latching into existing well components located in the well. Hydraulic fracturing fluids are pumped through the temporary frac string into the targeted geologic formation, and the temporary frac string is removed from the well when hydraulic fracturing is complete. The data presented above suggest that temporary frac strings were less effective at containing fluids during hydraulic fracturing than permanent well components.

Six (2-19) percent of re-fractures and re-completions reported a well component failure during hydraulic fracturing, compared to 2 (0.5-8) percent of initial fracture treatments. While the confidence intervals overlap, the point estimates suggest that re-fractures and re-completions may have been more likely than initial fracture treatments to experience a well component failure during hydraulic fracturing. As discussed below, re-fractures and re-completions may have been more likely to experience well component failures, because well design or well age can affect the mechanical integrity of the well or because temporary frac strings may be more likely to be used in re-fractures and re-completions.

When a new oil and gas production well is expected to be hydraulically fractured, the well can be designed to contain the fluids injected under the pressures expected during hydraulic fracturing (Ross and King, 2007; US EPA, 2011b). When hydraulic fracturing is not considered as part of the initial well design, the well may not have sufficient mechanical integrity to be re-completed using hydraulic fracturing, and remedial work on the well may be conducted prior to hydraulic fracturing (Fleckenstein et al., 2015; Martin and Rylance, 2007). For example, wells that are re-completed using hydraulic fracturing above their original completion interval may have insufficient cement at the shallower depth to contain the pressure applied during hydraulic fracturing. Hydraulic fracturing was conducted at shallower depths in 95 (75-99) percent of the re-completions identified in this study (Section 4.1). In some of these cases, cement was already present within the re-completion interval. In other cases, remedial cementing occurred in the re-completion interval prior to hydraulic fracturing.

Older wells, regardless of initial well design goals, may not be able to withstand the pressures applied during hydraulic fracturing, because mechanical integrity can change over time. The mechanical properties of well components, including casing and cement, can degrade over time, potentially creating pathways for subsurface fluid movement (Brufatto et al., 2003; Council of Canadian Academies, 2014; Ross and King, 2007; Smith et al., 2012). Re-fractures and re-completions may have been more likely to experience well component failures, because re-fractures and re-completions often occurred in older wells. The median estimated age of well components at the time of a re-fracture or re-completion was six years, compared to 45 days for initial fracture treatments.

Re-fractures and re-completions may also have been more likely to experience well component failures than initial fracture treatments, because temporary frac strings may be more likely to be used in re-fractures and re-completions. Temporary frac strings can be used in re-fractures and re-completions when there are concerns about whether the existing casing can withstand the pressures applied during hydraulic fracturing (Babaniyazov et al., 2012; Babaniyazov and Jackson, 2013; US EPA, 2011b). Temporary frac strings can also be used to isolate specific portions of the well for hydraulic fracturing. For example, re-completions at depths deeper than the initial fracture treatment may be conducted using a temporary frac string, because the temporary frac string can exclude existing, shallower perforations from hydraulic fracturing. Data presented in this report suggest that well component failures were more likely to occur when a temporary frac string was used for hydraulic fracturing than when permanent well components were used for hydraulic fracturing.

5.2. Potential Intersection of Fractures with Operator-Reported Protected Ground Water Resources or Existing Pathways

Fracture growth is affected by the characteristics of the hydraulic fracturing job and the characteristics of the subsurface. During hydraulic fracturing, injection volumes and pressures can be used to control fracture growth in the subsurface (Fisher and Warpinski, 2012; Flewelling et al., 2013; Kim and Moridis, 2015; Martin and Valkó, 2007). Formation characteristics, such as permeability, *in situ* stresses, and rock hardness, affect fracture creation, geometry, and growth (Fisher and Warpinski, 2012; Martin and Valkó, 2007; Canadian Water Network, 2015). Layered geology, where it exists, and natural fractures in the subsurface can hinder vertical fracture growth, causing induced fractures to remain within or near the targeted geologic formation (Fisher and Warpinski, 2012; Kim and Moridis, 2015).

Fractures created during hydraulic fracturing provide a pathway along which fluids can move in the subsurface. If local geologic conditions allow it, the intersection of induced fractures with operator-reported protected ground water resources can result in hydraulic fracturing fluids reaching drinking water resources. Additionally, the intersection of induced fractures with existing subsurface pathways may create a continuous pathway to underground drinking water resources along which fluids may travel. The potential for each situation is described below, using data available in the well files.

5.2.1. Potential Intersection of Fractures with Operator-Reported Protected Ground Water Resources

Information on the potential intersection of induced fractures with protected ground water resources reported by well operators was available for two cases: (1) hydraulic fracturing jobs with microseismic monitoring data and (2) wells in which the point of shallowest hydraulic fracturing was above the base of the operator-reported protected ground water resource.

In the first case, microseismic monitoring data was used to estimate the maximum vertical component of fracture growth in 0.5 (0.1-2) percent of the hydraulic fracturing jobs. As reported in Section 4.2.3, these data suggest that fractures created during these jobs grew no closer than 5,000 feet below operator-reported protected ground water resources. For these hydraulic fracturing jobs, the potential for induced fractures to intersect operator-reported protected ground water resources was likely low, because the distance separating the estimated fracture depth and the operator-reported base of the protected ground water resource was much larger (at least 5,000 feet) than the maximum vertical component of fracture growth estimated from microseismic monitoring data.

In the second case, the estimated separation distance between the point of shallowest hydraulic fracturing and the base of the operator-reported protected ground water resource was used to evaluate the potential for induced fractures to reach protected ground water resources in the absence of information on fracture growth.[23] As reported in US EPA (2015b), the estimated separation distance was less than zero feet in 0.4 (0.1-3) percent of the wells. In these wells, perforations used for hydraulic fracturing were placed shallower than the depth of the base of the operator-reported protected ground water resource. When perforations used for hydraulic fracturing are shallower than the base of the operator-reported protected ground water resource, the potential for induced fractures to directly intersect with the protected ground water resource is high, if the protected ground water resource is present at that depth. Based on the information contained in the well files, it was not possible to determine whether hydraulic fracturing fluid entered protected ground water resources in these cases.

For the majority of the wells represented in this study, it was not possible to assess with a high degree of certainty the potential for induced fractures to intersect operator-reported protected ground water resources, because they did not fall into either of the cases described above. The above cases, however, highlight the importance of the vertical separation distance between the point of shallowest hydraulic fracturing in a well and the base of protected ground water resources. If the vertical separation distance is less than, or comparable to, the vertical component of fracture growth, induced fractures may potentially reach protected ground water resources. Conversely, if the vertical separation distance is greater than the vertical component of fracture growth, induced fractures are unlikely to extend directly into protected ground water resources.

Data presented in Section 4.1 show that the estimated separation distance can change over time, if a well is re-completed using hydraulic fracturing.[24] Among the wells re-completed in this study, the

[23] As reported in US EPA (2015b), the separation distance was estimated for each study well by subtracting the depth of the operator-reported protected ground water resource from the measured depth of the point of shallowest hydraulic fracturing in the well. The estimated separation distance is not always equal to the true vertical separation distance, which is defined as the vertical distance between the point of shallowest hydraulic fracturing and the depth of the operator-reported protected ground water resource. In perfectly vertical wells, the estimated separation distance is equal to the true vertical separation. True vertical separation distances for deviated and horizontal wells are expected to be smaller than estimated separation distances.

[24] This may also be true for the wells that were re-fractured, because in this study, a re-fracture was defined as a hydraulic fracturing job in which any portion of the depth interval at which hydraulic fracturing was conducted overlapped with a

percent change in the estimated separation distance ranged from -147 percent to 64 percent, with a median of -22 percent.[25] A negative percent change indicates that the estimated separation distance became smaller when the well was re-completed. A positive percent change indicates that the estimated separation distance became larger when the well was re-completed. These data show that re-completing a well changes the separation distance between the point of shallowest hydraulic fracturing in a well and the operator-reported protected ground water resource.

The discussion presented above relied on depths to protected ground water resources reported by well operators (Section 3.3). The use of different depths would likely affect the results presented above.

5.2.2. Potential Intersection of Fractures with Existing Pathways

Computer modeling studies suggest that the connection of induced fractures to other features in the subsurface may lead to subsurface fluid movement within these features, if they are high-permeability pathways (Birdsell et al., 2015). Examples of these features include, but are not limited to, existing faults, natural fracture systems, nearby oil and gas production wells, and uncemented intervals within the hydraulically fractured production well (Ciezobka and Salehi, 2013; Energy Resources Conservation Board, 2012; Fisher and Warpinski, 2012; US EPA, 2015b). If these features are located within or near the fracture network created during hydraulic fracturing, then fluids may flow into these features either through intersecting pathways or fluid displacement.

Information on the relative location of induced fractures to existing faults, natural fracture systems, and nearby wells was generally not found in the well files, although 1 (0.4-4) percent of the wells represented in this study reported a frac hit. Frac hits were reported in the well files using the phrase "frac'd into [well name]." Frac hits are generally understood to occur when hydraulic fracturing at a well affects a nearby oil and gas production well (Energy Resources Conservation Board, 2012; King, 2014). The potential for hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, to move to underground drinking water resources during a frac hit depends on (1) the mechanical integrity of the offset (i.e., nearby) well and (2) the depth of hydraulic fracturing compared to the well construction characteristics of the offset well (e.g., location of cement). Information in the well files was insufficient to assess the potential for subsurface fluid movement to operator-reported protected ground water resources during the frac hits reported at the wells represented in this study.

Frac hits are often detected through changes in pressure or fluid production at offset wells (Ajani and Kelkar, 2012; Energy Resources Conservation Board, 2012). Because this study collected

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depth interval fractured in a previous job. Under this definition, it is possible that the point of shallowest hydraulic fracturing in a re-fracture was shallower than the point of shallowest hydraulic fracturing in a previous job.

[25] The percent change in the estimated separation distance was calculated using $[(d_{s2}\text{-}d_{s1})/d_{s1}]*100$, where d_{s1} is equal to the estimated separation distance between the point of shallowest hydraulic fracturing in job 1 (i.e., initial completion or previous hydraulic fracturing job) and the operator-reported protected ground water resource and d_{s2} is equal to the estimated separation distance between the point of shallowest hydraulic fracturing in job 2 (i.e., the re-completion of interest) and the operator-reported protected ground water resource. Note that the same value was used for the operator-reported protected ground water resource when calculating d_{s1} and d_{s2}. Of the 3,000 (100-5,900) re-completions identified in this study, 50 (20-70) were ineligible for this analysis, because no depth to a protected ground water resource was provided by the well operator.

information for the study wells and not offset wells, the reported occurrence of frac hits may be an underestimate. Similarly, the percentage of wells that did not report a frac hit [99 (96-100) percent] may be an overestimate.

5.3. Monitoring and Testing for Subsurface Fluid Movement During Hydraulic Fracturing

Each of the four types of monitoring and testing activities discussed in this report can provide information on subsurface fluid movement during hydraulic fracturing, because they provide information on the mechanical integrity of the well, fracture growth, and the potential intersection of induced fractures with existing pathways. Figure 13 illustrates how casing pressure tests, surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring are conducted and identifies which parts of the well can be monitored or tested during these activities.

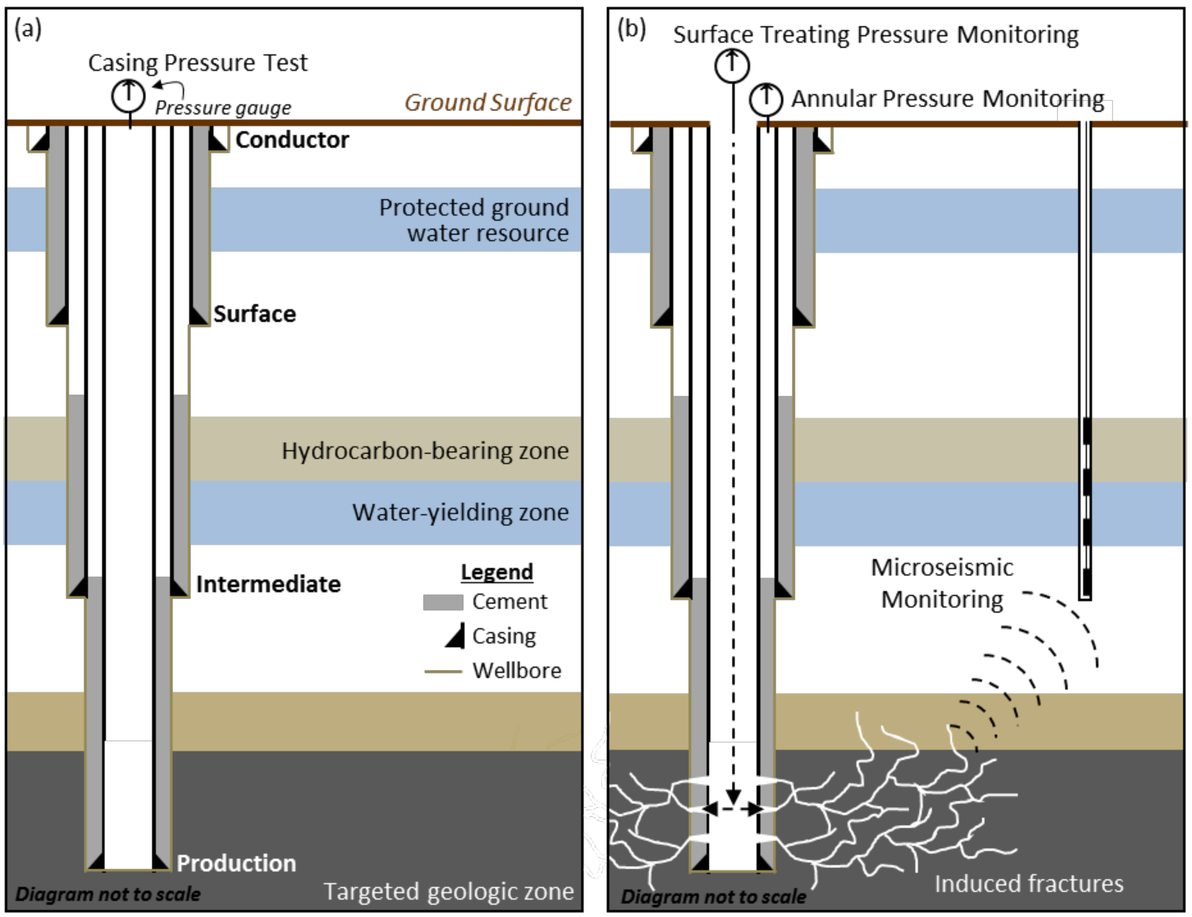

Figure 13. Generic well diagrams illustrating the four monitoring and testing activities discussed in this study. (a) Depiction of a casing pressure test, which can occur before or after hydraulic fracturing. (b) Depiction of surface treating pressure monitoring, annular pressure monitoring, and microseismic monitoring. These monitoring activities can occur during hydraulic fracturing.

5.3.1. Mechanical Integrity

Knowledge of the mechanical integrity of a well during hydraulic fracturing relies on information that can be obtained using three of the monitoring and testing activities illustrated in Figure 13: casing pressure tests, surface treating pressure monitoring, and annular pressure monitoring (King and King, 2013; US EPA, 2011b). As illustrated in Figure 13a, casing pressure tests can be conducted before or after hydraulic fracturing. During a casing pressure test, pressure is applied to the inside of the casing string used for hydraulic fracturing (e.g., the production casing in Figure 13a) and monitored to determine whether there are leaks in the well components being tested.

When conducted prior to hydraulic fracturing, casing pressure tests can indicate whether the well components are likely to contain the fluids injected during hydraulic fracturing (US EPA, 2011b). In this study, the casing test pressure was equally likely to be below the reported maximum treating pressure as above the reported maximum treating pressure when a casing pressure test was conducted prior to the hydraulic fracturing job (Section 4.2.2). Casing pressure tests in which the test pressure is less than the reported maximum treating pressure may occur if the reported maximum treating pressure was greater than the anticipated maximum treating pressure or if the casing pressure test was done for another purpose (e.g., packer setting tests, bridge plug setting tests, or remedial cementing tests). Casing pressure tests conducted at pressures less than the reported maximum treating pressure do not provide data, prior to hydraulic fracturing, that the well components used for hydraulic fracturing can contain fluids under the pressure applied during hydraulic fracturing.

Well component failures during hydraulic fracturing were reported by well operators in 3 (1-8) percent of the hydraulic fracturing jobs (Section 5.1). In 79 (28-99) percent of these jobs, there was no casing pressure test prior to hydraulic fracturing or, if there was a casing pressure test, it occurred after hydraulic fracturing or the casing test pressure was less than the reported maximum treating pressure. In 7 (2-25) percent of the jobs, a casing pressure test was conducted before hydraulic fracturing using a test pressure that was greater than the reported maximum treating pressure.[26] These data suggest that the reported rate of well component failures during hydraulic fracturing might have been lower, if casing pressure tests were conducted before hydraulic fracturing at test pressures greater than the maximum treating pressure among the jobs that reported a well component failure.

As illustrated in Figure 13b, surface treating pressure monitoring and annular pressure monitoring can occur during hydraulic fracturing. While both pressures are monitored at the wellhead, each provides information on different parts of the well. The surface treating pressure reflects the pressure created inside the casing string used for hydraulic fracturing (e.g., the production casing in Figure 13b) when hydraulic fracturing fluids are injected. Sudden or unexpected changes in the surface treating pressure can indicate casing or cement failure (US EPA, 2011b).[27] If there is a loss

[26] In 14 (8-22) percent of the hydraulic fracturing jobs with a well component failure, a casing pressure test was conducted outside of the date range used for the casing pressure test analysis described in Section 4.2.2. Casing test pressures were not compared to maximum treating pressures reported for these jobs.

[27] Sudden or unexpected changes in the surface treating pressure may also indicate equipment problems on the surface (e.g., a leak in a hose used to transfer hydraulic fracturing fluid) (US EPA, 2011b).

in casing and/or cement integrity during hydraulic fracturing, there may be a corresponding increase in the pressure in the annular space behind the casing string used for hydraulic fracturing (e.g., the space behind the production casing in Figure 13b) (Ross and King, 2007; US EPA, 2011b). Annular pressure increases can also occur because of pressure-induced casing expansion or thermal expansion of fluids already present in the annular space (Arnold, 1991; US EPA, 2011b).

The reported occurrence of annular pressure monitoring (Section 4.2) may have implications for the reported occurrence of well component failures. As noted in Section 5.1, well component failures were identified from text in documents contained in the well files and not through the EPA's review of the monitoring and testing activities considered in this study. Well component failures may not have been observed and documented in the well files if annular pressure monitoring was not conducted during hydraulic fracturing. Because the reported occurrence of annular pressure monitoring was 53 (27-77) percent, some hydraulic fracturing jobs may have experienced well component failures that were not detected. Therefore, the estimated occurrence of well component failures [3 (1-8) percent of hydraulic fracturing jobs] may be an underestimate. Additionally, the estimated percentage of hydraulic fracturing jobs that did not have a well component failure [97 (92-99) percent] may be an overestimate.

As described above, different monitoring or testing activities provide different types of information on mechanical integrity. Collectively, data from these tests can indicate whether unintentional subsurface fluid movement may occur or is occurring due to a well component failure. Depending on the particular well construction, failing a test or detecting unexpected pressure changes may suggest, but does not necessarily indicate, that impacts to drinking water resources will occur or have occurred. Rather, these results may suggest that one or more components of the well may not be performing as designed and that corrective actions may be necessary (US EPA, 2011b).

5.3.2. Potential Intersection of Fractures with Operator-Reported Protected Ground Water Resources or Existing Pathways

As described in Section 5.2, the potential intersection of induced fractures with operator-reported protected ground water resources or existing pathways that may connect to underground drinking water resources could result in subsurface fluid movement to drinking water resources during hydraulic fracturing. Knowledge of this type of situation relies on information about fracture growth, the intersection of newly-created fractures with existing pathways, and the depth of protected ground water resources. As discussed below, three of the four types of monitoring and testing activities included in this report can provide information on fracture growth and the intersection of fractures with existing pathways. None of the four monitoring and testing activities provide information on the depth of protected ground water resources.[28]

Fracture Growth. Information on fracture growth during hydraulic fracturing can be obtained through two of the monitoring and testing activities illustrated in Figure 13b: surface treating pressure monitoring and microseismic monitoring (Fisher and Warpinski, 2012; Malone and Ely, 2007; US EPA, 2011b; Warpinski, 2009). Changes in the surface treating pressure can be used to

[28] Section 3.3 provides a brief summary of the data sources used by well operators to report depths of protected ground water resources. A more detailed discussion can be found in US EPA (2015b).

estimate vertical fracture growth and fracture propagation under a given set of assumptions (Malone and Ely, 2007; US EPA, 2011b). While surface treating pressure was monitored during 97 (94-99) percent of the hydraulic fracturing jobs, the surface treating pressure monitoring data available in the well files was often insufficient to estimate fracture growth.[29]

Microseismic monitoring uses long arrays of sensitive receivers in offset wells at depths that are relatively close to the depth of hydraulic fracturing (Figure 13b), or on the surface, to detect energy released during microseismic events (Warpinski, 2009). As described in Fisher and Warpinski (2012):

> "Microseismic monitoring is based on detecting and locating the small reservoir movements that take place as a result of the [hydraulic] fracturing process. These movements are caused by changes in stress (fracture opening) and fluid pressure (leakoff), and they occur along natural fractures, bedding planes, and other weakness zones in the rocks with which the fracture makes contact. Therefore, it is an excellent technology for monitoring fracture growth by tracking the distribution of microseismic events."

While microseismic monitoring can be used to estimate fracture growth, it was reported to have been conducted in only 0.5 (0.1-2) percent of the hydraulic fracturing jobs. The relatively low reported occurrence of microseismic monitoring likely reflects the strategy generally used by the industry: microseismic monitoring is often used in the early stages of a field's development when fracture growth is uncertain (Council of Canadian Academies, 2014). As more wells are completed, additional microseismic monitoring is not conducted, because it is not expected to provide significant new information about fracture growth within the targeted geologic formation (Council of Canadian Academies, 2014).

As described in Section 5.2.1, the lack of hydraulic fracturing job-specific data on fracture growth among the wells represented in this study limited our ability to assess the potential for induced fractures to reach protected ground water resources reported by well operators.

Intersection of Fractures with Existing Pathways. Information on the intersection of induced fractures with existing pathways, or on subsurface fluid movement into existing pathways during hydraulic fracturing, can be obtained through surface treating pressure monitoring and annular pressure monitoring. Sudden or unexpected pressure changes in the surface treating pressure can indicate fracture growth out of zone, fracture growth into a permeable pathway (such as an offset well), or the cessation of fracture growth (US EPA, 2011b). Unexpected changes in the annular pressure can indicate the introduction of fluids into the annular space. Fluids can reach the annular space if induced fractures extend above the cement and into the annular space or if pressure changes in the subsurface push fluids through existing permeable pathways into the annular space (US EPA, 2011b).

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[29] The available data often included a single surface treating pressure value, which prevented an analysis of changes in the surface treating pressure.

With the possible exception of frac hits, information in the well files was insufficient to determine whether fractures created during hydraulic fracturing intersected existing pathways in the subsurface (Section 5.2.2).

6. Study Limitations

The survey design and data collection process have implications for the interpretation of the results presented in this report. As described in Section 3.4, the results presented in this report are statistically representative of onshore oil and gas production wells that were hydraulically fractured by nine oil and gas service companies between approximately September 2009 and September 2010. The results may not be statistically representative of all oil and gas production wells hydraulically fractured in the same time period. However, comparisons between the list of wells reported by the nine service companies and oil and gas production activities in the United States in 2009 and 2010 suggest that the observations made in this report are likely indicative of onshore oil and gas production wells hydraulically fractured during the time frame examined in this study (US EPA, 2015b).

Estimates of the frequency of occurrence of hydraulic fracturing characteristics and monitoring and testing activities are summarized at the national level. Given the survey design, it was not possible to display results at a smaller scale (e.g., by targeted geologic formation). The estimates presented in this report may be different for different regions of the country, because of differences in local geologic characteristics, regulatory requirements, and company preferences. The estimates may also not apply to wells hydraulically fractured after 2010, as hydraulic fracturing practices and regulatory requirements change over time. Despite these limitations, the data presented in this report provide an overview of onshore oil and gas production wells hydraulically fractured by the nine service companies during the time frame of this study.

Finally, the results presented in this report are generated from data provided by oil and gas well operators. The data are limited in scope to the information requested by the EPA and the information provided by the well operators. While quality assurance and quality control measures were used to ensure that analyses presented in this report accurately reflected the data supplied by the well operators, the EPA did not attempt to independently and systematically verify the data. Consequently, the results presented in this report reflect the scope of the information request and are of the same quality as the supplied data and the database created by the EPA (Section 3.5).

7. Summary

This report presents the results of a survey of onshore oil and gas production wells hydraulically fractured by nine oil and gas service companies in the United States during 2009 and 2010. Two factors that affect the potential for subsurface fluid movement during hydraulic fracturing were examined: the mechanical integrity of the hydraulically fractured oil and gas production well and the potential intersection of newly-created fractures with protected ground water resources reported by well operators or nearby existing pathways.

Situations that potentially allowed hydraulic fracturing fluids to move to protected ground water resources reported by well operators were identified in a small number of wells. These situations included:

> *Well integrity failures during hydraulic fracturing [0.5 (0.1-2) percent of the hydraulic fracturing jobs].* In these cases, well components (e.g., casing, cement, or packers) failed during hydraulic fracturing, and no additional casing or cement barriers separated the well components that failed from the operator-reported protected ground water resources. Information in the well files suggested that, in these cases, hydraulic fracturing fluid entered the annular space between the casing string used for hydraulic fracturing and the surrounding geology at depths corresponding to protected ground water resources reported by well operators. Based on the information contained in the well files, it was not possible to determine whether hydraulic fracturing fluid moved from the annular space into protected ground water resources in these cases.
>
> *Perforations used for hydraulic fracturing were shallower than the base of protected ground water resources reported by well operators [0.4 (0.1-3) percent of the wells] (US EPA, 2015b).* When perforations used for hydraulic fracturing are shallower than the base of the operator-reported protected ground water resource, the potential for induced fractures to directly reach the protected ground water resource is high, if the protected ground water resource is present at that depth. Based on the information contained in the well files, it was not possible to determine whether hydraulic fracturing fluid entered protected ground water resources in these cases.

Information on the relative location of newly-created fractures to existing pathways was generally not found in the well files, although 1 (0.4-4) percent of the wells reported a frac hit. Frac hits occurred when hydraulic fracturing at a well affected a nearby oil and gas production well. It was not possible to determine whether hydraulic fracturing fluids, or subsurface fluids affected by hydraulic fracturing, reached operator-reported protected ground water resources during the frac hits, because available information in the well files was insufficient to determine whether fluids flowed along the outside of the nearby oil and gas production well and into protected ground water resources.

These results, as well as other information on hydraulic fracturing characteristics and monitoring and testing activities before and during hydraulic fracturing, highlight important well design, construction, and operation practices that should be considered when assessing the potential impacts of hydraulic fracturing on drinking water resources.

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Appendix: Variance Estimation

Variance estimates used to calculate 95 percent confidence intervals presented in this report were conducted following the approach described in Appendix A of US EPA (2015b) except in two cases. First, if an analysis was conducted on a subpopulation using data from fewer than two well operators in each strata, the approach for estimating the variance was adjusted by collapsing strata, as described below. Second, if a percentage estimate had an estimated design effect less than one (usually for a rare characteristic, such as near zero percent of the wells or hydraulic fracturing jobs), the approach was adjusted by setting the design effect to 1.0, also described below. It is anticipated that the design effect is actually greater than 1.0, but difficult to estimate with so few respondents. These adjustments are expected to provide more accurate 95 percent confidence intervals.

Collapsing Strata. As described in Appendix A of US EPA (2015b), the strata used for variance estimation are the first-stage strata used to select well operators. The strata used for variance estimation include two strata with two large well operators each (Strata 1 and 2), one stratum with all medium well operators (Stratum 3), and one stratum with all small well operators (Stratum 4).

Because variance estimates measure the consistency (or variability) between well operators within the same stratum, each variance stratum must contain at least two well operators. When fewer than nine well operators are included in an analysis, any of the four variance strata described above (Strata 1-4) may consist of only one well operator. When this occurred, strata were collapsed (Wolter, 1985) so that two or more well operators were in each strata. The sequential rules for collapsing strata were:

(1) If Stratum 1 or Stratum 2 did not have at least two well operators with study wells in the subpopulation, merge all well operators from Stratum 1 and Stratum 2 into Stratum 2.

(2) If Stratum 3 or Stratum 4 did not have at least two well operators with study wells in the subpopulation, merge all medium and small well operators from Stratum 3 and Stratum 4 into Stratum 3.

(3) If Stratum 2 did not have at least two well operators with study wells in the subpopulation, merge all well operators from Stratum 2 into Stratum 3.

(4) If Stratum 3 did not have at least two well operators with study wells in the subpopulation, merge all well operators from Stratum 3 into Stratum 2.

(5) If Stratum 2 did not have at least two well operators with study wells in the subpopulation, do not calculate the confidence interval, because there are not enough well operators.

When strata were collapsed, the equations listed in Appendix A of US EPA (2015b) were adjusted to account for the correct number of well operators, strata, and degrees of freedom.

Design Effect. The design effect is the ratio of the estimated variance from the survey design used in this study divided by the variance of a simple random sample of the same size (Kish, 1965). In most cases, the design effect should be greater than one, because clustering study wells within well operators reduces the independence of the sampled wells (i.e., there are some commonalities because a well operator likely uses similar practices across their wells). Unequal sampling weights also increase the design effect, because some of the study wells become more important to the variance estimate than others. Both of these factors—multiple study wells from a single well operator and unequal sampling weights—generally reduce the effective sample size from what would be expected in a simple random sample and increase the associated design effect.[30]

The estimated variance from such small samples is relatively imprecise and may result in estimated design effects less than one even through the true design effect is greater than one. Although design effects less than one are possible, they are not expected in this study. As a result, estimated design effects less than one were interpreted as an indication that the variance estimate was unusually low due to chance. This is more likely to occur when estimating percentages for rare characteristics and when there are fewer well operators from which to estimate the variance. In order to protect against variance estimates for percentages that are unusually small by chance and associated confidence intervals that imply greater precision than warranted, the design effects for percentages were restricted to be greater than or equal to 1.0. When the calculated design effect for a percentage was less than 1.0 after collapsing strata (if needed), it was set equal to 1.0. This replaced the sample variance estimate with the simple random sampling variance, which increased the width of the confidence interval. This does not completely ameliorate the issue of too narrow confidence intervals, because the true design effect is likely greater than 1.0. Therefore, the appropriate confidence intervals may be wider than the reported confidence intervals. A similar adjustment for the estimated number of wells (as opposed to percent) was not used, because there is no simple formula for the random sample variance of sums.

Appendix References

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[30] To the extent that a characteristic is strongly related to well operator size, the stratification may reduce the design effect for that characteristic. As described in US EPA (2015b), well operator size was defined by the number of well identifiers included in the service company well list that were associated with a given well operator.

Glossary

Annulus: The space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow. (ref 3)

Borehole: The wellbore itself, including the open hole or uncased portion of the well. (ref 3)

Casing pressure test: Defined in this report as any surface pressure applied and held to a portion or all of the casing string used for hydraulic fracturing (i.e., production casing or temporary frac string).

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.

Cement evaluation log: Any of several kinds of logs run within cemented casing that can be interpreted to evaluate cement presence, apparent cement bond quality, or the effectiveness of cement forming an annular seal. Cement evaluation logs included standard acoustic cement bond logs, ultrasonic image tool logs, and temperature logs.

Completion report: Often provided by well operators, this is a daily log of the activities performed at a well after it has been drilled but before it is brought online for oil/gas production. Information about 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.

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 5)

Formation: A body of earth material with distinctive and characteristic properties and degree of homogeneity in its physical properties. (ref 4)

Frac hit: Occurs when hydraulic fracturing at a well affects an offset oil and gas production well. (ref 2)

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 from underground rock formations. Hydraulic fracturing involves the injection of fluids under pressures great enough to fracture the oil- and gas-containing formations. (ref 5)

Hydraulic fracturing job: Defined in this report as one or more stages in which the time between consecutive stages was less than or equal to 90 days.

> **Initial fracture treatment:** Defined in this report as the first reported hydraulic fracturing job that occurred at a well.
>
> **Re-completion:** Defined in this report as a hydraulic fracturing job in which an entirely new interval of the well was fractured, when compared to previous hydraulic fracturing jobs.
>
> **Re-fracture:** Defined in this report as a hydraulic fracturing job in which any portion of the fractured interval overlapped with a fractured interval from a previous job.

Hydraulic fracturing stage: Defined in this report as a specific measured depth interval for which hydraulic fracturing began on a specific date.

Lateral component of fracture growth: When microseismic reports contain a plan-view of fracture growth during a hydraulic fracturing job, this is the greatest distance from the point of fracture origination along the wellbore, as measured perpendicular to the wellbore trace.

Maximum treating pressure: Defined in this report as the largest reported surface treating pressure per hydraulic fracturing job.

Mechanical integrity: The ability of a well to contain fluids within the well and prevent fluid movement along the outside of the well, between the outermost casing and the wellbore. (ref 1)

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 3)

Microseismic report: A report describing results from microseismic monitoring. The report typically contains differently-oriented views (such as plan view and side views) showing the microseismic events detected during hydraulic fracturing. These microseismic events are commonly assumed to be related to the growth of induced fractures. The report may show mapped microseismic events at the stage level of the hydraulic fracturing job and may also state the magnitude of lateral and vertical fracture growth.

Open hole: The uncased portion of a well. All wells, at least when first drilled, have open hole sections. While most completions are cased, some are open, especially in horizontal or extended-reach wells where it may not be possible to cement casing efficiently. (ref 3)

Packer: A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. (ref 3)

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 3)

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

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

Post-frac report: A report generated by the service company that conducts the hydraulic fracturing job on a production well. The report typically, but not always, contains a record of the stages of the hydraulic fracturing job, including timing and depth interval, the volume of additives and amount of proppant pumped during each stage, the injection rates and associated pump pressures applied during each stage. The report may or may not contain information about monitored wellhead pressure in an annular space behind the casing used for hydraulic fracturing.

Protected ground water resource: 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 3)

Surface treating pressure: The pressure during hydraulic fracturing that builds within the casing used for hydraulic fracturing. The surface treating pressure is measured at or near, but not below, the wellhead.

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

Temporary frac string: A temporary well component that is lowered into the well and secured at base of the well using a packer or by latching into existing well components located in the well. Hydraulic fracturing takes place through the temporary frac string, which is removed when hydraulic fracturing is complete.

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 3)

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 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 component of fracture growth: When microseismic reports contain a side-view of fracture growth during a hydraulic fracturing job, this is the greatest vertically upward distance from the point of fracture origination along the well.

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 3)

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 3)

Glossary References

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