EXHIBIT 1

NORTHERN PLAINS

RESOURCE COUNCIL

Montana Board of Oil and Gas Conservation
Board members
Attn: Jim Halvorson, Administrator
2535 St. Johns Avenue
Billings, MT 59102

February 1, 2017

Re: New Rule I on Notification of Application for Permit to Drill

Dear Members of the Montana Board of Oil and Gas Conservation,

Northern Plains Resource Council would like to thank and applaud the Board of Oil and Gas Conservation for finalizing New Rule I and establishing notification for neighbors of oil and gas drilling. Because of your leadership, Montanans living, working, and going to school near oil and gas drilling will now get information on projects before a permit is issued.

Northern Plains Resource Council, as a grassroots conservation and family agriculture group, firmly believes in the value of peoples' participation in the decisions that affect their lives. New Rule I makes participation more of a reality and promotes good communication between companies and neighbors. New Rule I is a well-thought out, reasonable measure and Northern Plains appreciates the resources and attention the Board put into the rule's development.

Sincerely,

Deborah Hanson

Deborah Hanson

Chair, Northern Plains Resource Council Oil and Gas Task Force
220 South 27th Street, Suite A
Billings, MT 59101

EXHIBIT 2

NORTHERN PLAINS
RESOURCE COUNCIL

Montana Board of Oil and Gas Conservation
Board members
Attn: Jim Halvorson, Administrator
2535 St. Johns Avenue
Billings, MT 59102

February 1, 2017

Re: Consideration of initiating rulemaking on hydraulic fracturing disclosure

Dear Members of the Montana Board of Oil and Gas Conservation,

Northern Plains Resource Council is excited to see the Board re-considering initiating rulemaking on hydraulic fracturing.

As Northern Plains noted in our public comment when the Board considered the petition for rulemaking on hydraulic fracturing disclosure in September, 2016, Northern Plains is keenly interested in the transparency and accessibility of information about chemicals used during oil and gas development and exploration. In consideration of our members' abiding interest in protecting water, Northern Plains reaffirms its support of revising ARM 36.22.608 and 36.22.1015-36.22.1016 to include pre-stimulation disclosure of chemicals used during oil and gas development and exploration and to place limits on the trade secret exemption.

Early disclosure of chemicals would improve the effectiveness of landowners' baseline water testing and, ultimately, protect both landowners and operators. Without chemical disclosure before drilling operations begin, landowners have to essentially use an "educated guess" when deciding on testing parameters. Pre-drilling chemical disclosure would allow landowners to test their water for the specific chemicals planned for use in operations before drilling begins and would lay the foundation for recourse for landowners in cases of legitimate and provable water contamination. On the other hand, early chemical disclosure that allows targeted baseline water testing could also shield operators from unfounded claims of water contamination by eliminating the uncertainty in pre-drilling water quality conditions.

The trade secret exemption poses similar challenges for landowners in protecting and documenting their pre-drilling water quality. If early chemical disclosure is not as comprehensive as possible, effective baseline water testing remains problematic. As other states, such as Wyoming, have successfully developed frameworks to review and promote discretion in the use of trade secrecy claims, Montana should follow suit and adopt a similar framework.

Northern Plains recognizes and appreciates the Board's continued attention to increasing the accessibility of oil and gas drilling information to Montana's public. Revisions to ARM 36.22.608 and 36.22.1015-36.22.1016 to require pre-drilling chemical disclosure and limit trade secret exemptions would substantially improve the ability of landowners in Montana to make informed decisions when oil and gas development is occurring on their property.

Sincerely,

Deborah Hanson

Deborah Hanson

Chair, Northern Plains Resource Council Oil and Gas Task Force
220 South 27th Street, Suite A
Billings, MT 59101

EARTHJUSTICE

Montana Board of Oil and Gas Conservation
2535 St. Johns Avenue
Billings, MT 59102

January 30, 2017

Re: Rulemaking on Hydraulic Fracturing Chemical Disclosure

To the Members of the Montana Board of Oil and Gas Conservation:

Please accept the following public comments concerning the Board's reconsideration of the need for rulemaking to amend the Board's current regulations governing disclosure of hydraulic fracturing chemicals, ARM 36.22.608 and 36.22.1015-.1016. These comments are submitted on behalf of Montana Environmental Information Center, Natural Resources Defense Council, Dr. Mary Anne Mercer, David Katz, Anne Moses, Jack and Bonnie Martinell, Dr. Willis Weight, and Dr. David Lehnherr (collectively, the "Commenters").

The Commenters support the Board's decision to take a second look at the need for rulemaking to expand public access to information about the chemicals used for hydraulic fracturing, or "fracking," in our state. The issue of fracking chemical disclosure is of vital importance to Montana landowners and citizens who live, work, farm, and ranch near oil and gas operations. For that reason, the Commenters joined with other Montana landowners in July 2016 in petitioning the Board to undertake rulemaking to amend its current regulations governing disclosure of fracking chemical information, ARM 36.22.608 and 36.22.1015-.1016 (the "Disclosure Rules"). The petitioners specifically requested that the Board amend the existing Disclosure Rules to (1) require oil and gas operators to disclose to the Board, and the public, the specific chemicals they plan to use in a fracking job at least 45 days before fracking occurs; and (2) require operators to substantiate claims that specific fracking chemicals are exempt from disclosure as trade secrets and provide that the Board shall determine trade secret status before allowing any exemption from disclosure. As explained in the citizen rulemaking petition (hereafter, the "Petition"), broader chemical disclosure is needed to ensure that landowners have access to chemical information that is essential to protect their water resources, property rights, and health; and to bring the Board's Disclosure Rules into compliance with the Montana Constitution.

The Commenters hereby incorporate by reference their July 25, 2016, Petition and supporting exhibits and the written comments and supporting exhibits submitted to the Board at the Board's September 22, 2016, public meeting concerning the Petition. In addition, the Commenters offer the following additional points to support their request for rulemaking as outlined in the Petition and respond to the reasons the Board gave for denying the Petition in September 2016:

NORTHERN ROCKIES OFFICE 313 EAST MAIN STREET BOZEMAN, MT 59715

T: 406.586.9699 F: 406.586.9695 NROFFICE@EARTHJUSTICE.ORG WWW.EARTHJUSTICE.ORG

A. The Supreme Court's Decision in *Carbon County Resource Council v. Montana Board of Oil and Gas Conservation* Does Not Constrain the Board's Authority to Initiate Rulemaking

In the Board's September 23, 2016, decision denying the Petition, the Board stated that the Montana Supreme Court's then-pending decision in *Carbon County Resource Council v. Montana Board of Oil and Gas Conservation*, No. DA 15-0613 ("*CCRC*"), needed to "run its course" before the Board initiates rulemaking to amend the Disclosure Rules. The Commenters disagree that the *CCRC* appeal presented any overlapping issues with the Petition that precluded Board action on the Petition in September 2016. Regardless, the Supreme Court issued a final decision in the *CCRC* appeal on September 27, 2016, *see Carbon Cty. Res. Council v. Mont. Bd. of Oil & Gas Conservation*, 2016 MT 240, 385 Mont. 51, 380 P.3d 798 (attached as Exhibit 1), and that decision makes clear that *CCRC* does not constrain the Board's authority to reform the Disclosure Rules as requested in the Petition.

CCRC involved an as-applied constitutional challenge to the Board's "48-hour notice rule," which requires oil and gas operators intending to hydraulically fracture an exploratory oil and gas well to notify the Board of their intent to do so at least 48 hours in advance, ARM 36.22.608(2). *See CCRC*, ¶ 8. Specifically, the *CCRC* plaintiffs alleged that the Board's application of the 48-hour notice rule in approving chemical stimulation of an exploratory well in Carbon County violated the plaintiffs' constitutional right to participate. *See id.* ¶¶ 5-8. Accordingly, the *CCRC* appeal did not raise any issues concerning the matters raised in the Petition and now back before the Board, *i.e.*, the requirements for public disclosure of fracking chemical information pursuant to the Board's Disclosure Rules. Further, the chemical disclosure issues at hand do not implicate the requirements for public participation in connection with activities authorized pursuant to the Board's 48-hour notice rule.

This conclusion is borne out in the Supreme Court's decision resolving the *CCRC* appeal. After reversing the district court's judgment that the *CCRC* plaintiffs' claim was unripe, *see id.* ¶ 15, the Supreme Court ruled that the Board did not violate the *CCRC* plaintiffs' right to participate in approving the specific well stimulation activities at issue in that case, *id.* ¶¶ 23-25. Consequently, the Supreme Court's decision in *CCRC* has no effect on the Board's authority to grant the Petition and initiate rulemaking to strengthen the Disclosure Rules, and it does not provide a valid reason to deny the Petition.

B. The Federal Defend Trade Secrets Act Does Not Constrain the Board's Authority to Initiate Rulemaking

In denying the fracking chemical disclosure Petition in September 2016, the Board also stated that it was "uncertain about the new federal trade secret law and the impact it may have on anything the Board does today." The federal law at issue, the Defend Trade Secrets Act of 2016,[1] also poses no obstacle to the Board's amending the Disclosure Rules as requested in the Petition.

[1] Pub. L. No. 114-153, 130 Stat. 376 (114th Cong. May 11, 2016), *codified at* various sections of 18 U.S.C. ch. 90.

The Defend Trade Secrets Act is concerned with corporate espionage; accordingly, it provides a federal civil cause of action for trade secret misappropriation by business competitors. See 18 U.S.C. § 1836(b)(1), (c); S. Rep. No. 114-220 at 3, 5, 114th Cong., 2d. Sess. (Mar. 7, 2016); H.R. Rep. No. 114-529 at 1-2, 114th Cong., 2d Sess. (Apr. 26, 2016). The Act does not address disclosure of fracking chemical information, or any other commercial information, pursuant to state or federal regulatory requirements or the protection of alleged trade secret information in that context. Importantly, the Act expressly does not prohibit any otherwise lawful activities by state governments, affect lawful disclosures under the federal Freedom of Information Act, or preempt state remedies for trade secret misappropriation. See 18 U.S.C. §§ 1833(a)(1), 1838; S. Rep. No. 114-220 at 10; H.R. Rep. No. 114-529 at 5-6, 14. Moreover, the Defend Trade Secrets Act is intended to conform to the Uniform Trade Secrets Act, which governs the scope of trade secret protection in Montana. See S. Rep. No. 114-220 at 3, 10; H.R. Rep. No. 114-529 at 2, 13-14.

Accordingly, the Defend Trade Secrets Act does not constrain the Board's authority to amend the Disclosure Rules as requested in the Petition or provide a valid reason to deny the Petition.

C. Adopting the Proposed Regulatory Reforms Would Not Hinder the Protection of Legitimate Trade Secrets

In denying the Petition in September 2016, the Board also expressed concern that adopting the regulatory reforms requested in the Petition could hinder the Board's ability to protect trade secrets and could expose the Board or its staff to liability issues. Those concerns are unfounded and do not provide a valid reason to deny the Petition.

As the petitioners explained in comments to the Board in September, the Petition does not seek to abolish the Disclosure Rules' trade secrets exemption or compel the Board to disclose legitimate trade secret information to the public. Nor could it, as Montana law requires the Board to withhold legitimate trade secret information from the public. See Great Falls Tribune v. Mont. Pub. Serv. Comm'n, 2003 MT 359, ¶ 39, 319 Mont. 38, 82 P.3d 876 (holding that constitutional right-to-know does not require disclosure of trade secrets protected under Uniform Trade Secrets Act); Mont. Code Ann. § 2-6-1002(11) (Montana Public Records Act exempting from definition of "public information" accessible to the public any "confidential information that must be protected against public disclosure under applicable law").[2]

Accordingly, the Petition asks the Board to amend the trade secrets exemption so that only legitimate trade secret information is shielded from disclosure. To accomplish that, the Petition asks the Board to amend its rules to require oil and gas operators to submit to the Board evidence demonstrating that information they wish to withhold as trade secrets actually qualifies as such under Montana law, and to provide that the Board will make a determination as to

[2] In its September 2016 decision denying the Petition, the Board suggested that Montana law and Wyoming law are different in this respect, but in fact Wyoming law also requires state agencies to withhold legitimate proprietary information from public disclosure. See Wyo. Stat. Ann. § 16-4-203(d)(v) (exempting from disclosure under public records laws trade secrets and confidential commercial information).

whether trade secret claims are valid before allowing operators to take advantage of the disclosure exemption. This amended framework would ensure that the Board continues to shield legitimate trade secret information from public disclosure while providing lawful public access to information about all other chemicals approved for fracking in Montana.

D. The Board Has the Authority and Obligation to Take Action

Finally, the Board stated in its September 2016 decision denying the Petition that "[a] decision this complicated and with such broad implications should be made as part of the legislative process and not by the seven members of the Board serving as governor appointees." However, this rationale does not provide a valid basis for denying the Petition and refusing to initiate rulemaking.

The Board has undisputed authority to regulate fracking chemical disclosure, as it has done since 2011 pursuant to the existing Disclosure Rules. Indeed, the Supreme Court has recognized the Board's broad authority "to take measures to … prevent contamination of or damage to surrounding land or underground strata [from oil and gas development], and to promote environmentally sound development of oil and gas in Montana." *Mont. Wildlife Fed'n v. Mont. Bd. of Oil & Gas Conservation*, 2012 MT 128, ¶ 8, 365 Mont. 232, 280 P.3d 877 (citing Mont. Code Ann. § 82-11-111).

The Board also has a clear duty to act on the Petition and initiate reforms of the Disclosure Rules. In the Petition and supporting materials, the Commenters have explained that the existing Disclosure Rules' limited requirements for pre-fracking chemical disclosure and framework for exempting alleged trade secrets are fundamentally unfair to Montana landowners and the broader public and, more critically, the existing trade secrets exemption violates the Montana Constitution. Further, the Board is the state government body charged with the regulation of oil and gas development, the prevention of contamination from those activities, and the promotion of environmentally sound development practices. *See id.*; Mont. Code Ann. § 82-11-111. Under these circumstances, the Board has a duty to the people of Montana to take action that is within the Board's jurisdiction and necessary to safeguard citizens' constitutional rights and fundamental fairness. Consequently, the Board's stated preference that the legislature address the issue of fracking chemical disclosure does not provide a legitimate basis for the Board's refusal to act. *See Columbia Falls Elementary School Dist. No. 6 v. State*, 2005 MT 69, ¶ 48, 326 Mont. 304, 109 P.3d 257 (Nelson, J., concurring) ("choosing not to act, is an act in and of itself" and must be rationally justified by consideration of the relevant factors and evidence in the record); *accord Clark Fork Coal. v. Mont. Dep't of Envtl. Quality*, 2008 MT 407, ¶ 43, 347 Mont. 197, 197 P.3d 482.

E. Conclusion

For the reasons stated in the Commenters' July 2016 Petition and supporting exhibits and comments, amendments to the Board's Disclosure Rules—specifically, the rules' requirements for pre-fracking chemical disclosure and framework for exempting alleged trade secret information—are necessary to protect the interests of Montana citizens in safeguarding their property, health, and environment and to comply with the Montana Constitution.[3] Further, for the reasons stated above, the Board's September 2016 decision to deny the Petition was unsupported. The Board should take the opportunity afforded by its reconsideration of the Petition to make the right decision for Montanans and initiate rulemaking to strengthen the Disclosure Rules.

Sincerely,

Katherine K. O'Brien
Earthjustice
313 East Main Street
Bozeman, Montana 59715
(406) 586-9699
kobrien@earthjustice.org

Counsel for Montana Environmental Information Center, Natural Resources Defense Council, Dr. Mary Anne Mercer, David Katz, Anne Moses, Jack and Bonnie Martinell, Dr. Willis Weight, and Dr. David Lehnherr

[3] Since the Board's decision to deny the Petition in September 2016, the body of evidence substantiating the public's concerns over the safety of fracking chemicals has grown. Notably, in December 2016 the U.S. Environmental Protection Agency released its final "Study of Hydraulic Fracturing for Oil and Gas and Its Potential Impact on Drinking Water Resources," which concluded that hydraulic fracturing activities can adversely impact drinking water resources. *See* U.S. EPA, Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States (Final Report) 1-2, 18, 20, 22, 24-27, 29, 31, 36-37, 41. U.S. Environmental Protection Agency, Washington, D.C., EPA/600/R-16/236F, 2016 (attached as Exhibit 2). Moreover, the EPA assessment concluded that greater access to information about the chemicals used for fracking is necessary for governments and the public to fully understand the risks associated with fracking and the nature, frequency, and severity of fracking impacts on water resources. *See id.* at 40-41.

EXHIBIT 1
To Comments Re: Rulemaking on Hydraulic Fracturing Chemical Disclosure

DA 15-0613

IN THE SUPREME COURT OF THE STATE OF MONTANA

2016 MT 240

CARBON COUNTY RESOURCE COUNCIL,
a Montana Non-profit public benefit corporation,
and NORTHERN PLAINS RESOURCE COUNCIL,
Montana Non-profit, public benefit corporation,

Plaintiffs and Appellants,

v.

MONTANA BOARD OF OIL AND GAS CONSERVATION,

Defendant and Appellee.

APPEAL FROM: District Court of the Thirteenth Judicial District,
In and For the County of Yellowstone, Cause No. DV 14-0027
Honorable Mary Jane Knisely, Presiding Judge

COUNSEL OF RECORD:

For Appellants:

Jack R. Tuholske, Tuholske Law Office, P.C., Missoula, Montana

Amanda R. Knuteson, Knuteson Law Office PLLC, Bozeman, Montana

For Appellee:

Robert Stutz, James M. Scheier, Assistant Attorneys General, Helena, Montana

For Amicus Curiae Montana Petroleum Association:

Colby L. Branch, Jeffery J. Oven, Shalise C. Zobell, Crowley Fleck PLLP, Billings, Montana

Submitted on Briefs: June 15, 2016

Decided: September 27, 2016

Filed:

Clerk

Justice Beth Baker delivered the Opinion of the Court.

¶1 Carbon County Resource Council and Northern Plains Resource Council (collectively Resource Councils) oppose hydraulic fracturing at the Hunt Creek 1-H well, an exploratory gas well in Carbon County, Montana. Resource Councils challenged the Montana Board of Oil and Gas Conservation's (the Board) approval of well stimulation activities at the site, claiming that they were denied a meaningful opportunity to participate in the process. The Thirteenth Judicial District Court held that Resource Councils' concerns were speculative and therefore not ripe for judgment. We disagree and hold that Resource Councils' claims are ripe for judicial review. We conclude that the Board did not violate their right to participate in its consideration of the permit issued in this case. We thus find it unnecessary to decide whether the Board's "48-hour notice" rule may be unconstitutional in other circumstances.

PROCEDURAL AND FACTUAL BACKGROUND

¶2 The Montana Constitution guarantees citizens a "reasonable opportunity" to participate in government operations. Mont. Const. art. II, § 8. In executing this constitutional mandate, agencies are obligated to "develop procedures for permitting and encouraging the public to participate in agency decisions that are of significant interest to the public." Section 2-3-103, MCA. As a quasi-judicial state agency administratively attached to the Department of Natural Resources and Conservation, the Board is required to ensure public participation in its decision-making procedural processes. Sections 2-3-103, 2-4-201, 2-15-3303, MCA.

¶3 The Board's procedural rules require oil and gas well operators to file an application for a permit to drill with the Board. Admin. R. M. 36.22.601(1). If the proposed well is outside of an existing oil and gas field delineated by the Board, the operator must publish notice of its intent to drill and file proof of publication with the Board. Admin. R. M. 36.22.601(1). The application for a permit to drill must be set for notice and public hearing if an interested person demands an opportunity to be heard pursuant to the procedures provided for under the relevant Administrative Rules. Admin. R. M. 36.22.601(4). Following a hearing, the Board may either grant or deny the permit. Admin. R. M. 36.22.601(5). If the Board grants the permit, it may impose "such conditions" as it finds "proper and necessary." Admin. R. M. 36.22.601(5)(a).

¶4 Well completion activities such as "hydraulic fracturing, acidizing, or other chemical stimulation . . . are considered permitted activities under the drilling permit for that well only if the processes, anticipated volumes, and types of materials planned for use are expressly described in the permit application for that well." Admin. R. M. 36.22.608(1).[1] Admin. R. M. 36.22.608(2) (the Rule) provides that for exploratory wells—like the well at issue here—the well operator must notify the Board of its "intent to stimulate or chemically treat a well . . . prior to commencing such activities." The well operator must describe the "fracturing, acidizing, or other chemical treatment" in the

[1] "Hydraulic fracturing" or "fracturing," also known as "fracking," "fracing," or "hydro-fracking," is an oil and gas extraction technique. The Administrative Rules of Montana define "fracturing" as "the introduction of fluid that may or may not carry in suspension a propping agent under pressure into a formation containing oil or gas for the purpose of creating cracks in said formation to serve as channels for fluids to move to or from the well bore." Admin. R. M. 36.22.302(28).

notice, and the operator must give the Board notice "at least 48 hours before commencement of well stimulation activities." Admin. R. M. 36.22.608(2)(a). A well operator is required to disclose the amount and type of materials used in its well stimulation activities, Admin. R. M. 36.22.1015, and comply with safety and well control requirements if it engages in hydraulic fracturing, Admin. R. M. 36.22.1106.

¶5 In October 2013, Energy Corporation of America (Energy Corp.) announced that it planned to develop oil and gas leases in the Beartooth Mountains. Energy Corp. then filed an application with the Board for a permit to drill an exploratory oil and gas well in Carbon County known as the Hunt Creek 1-H well (Hunt Creek Well). Energy Corp.'s application did not describe any well completion activities pursuant to Admin. R. M. 36.22.608(1). Resource Councils, which are affiliated grassroots conservation and agriculture groups, objected to the permit. Despite procedural problems with Resource Councils' objection, the Board held a hearing on Energy Corp.'s drilling permit application in February 2014. Nine local residents and an expert testified on behalf of Resource Councils. The residents presented their concerns with the permit application, the environmental assessment's adequacy, and the potential environmental impacts of hydraulic fracturing at the Hunt Creek Well. The expert, an environmental geologist, testified and submitted a report highlighting the risks associated with the proposed drilling plan as well as risks associated with hydraulic fracturing at the site.

¶6 During the hearing, the Board noted that Energy Corp. proposed drilling an exploratory well to evaluate the site's potential for development. The Board emphasized that Energy Corp.'s application did not propose hydraulic fracturing and that there was no indication from the application that hydraulic fracturing was planned in the future. At the close of the hearing, the Board approved the permit with the condition that Energy Corp. comply with certain water standards should it propose hydraulic fracturing at the Hunt Creek Well in the future. The Board's order approving the permit reiterated that Energy Corp. did not propose hydraulic fracturing at the Hunt Creek Well.

¶7 On July 7, 2014, Energy Corp. submitted a sundry notice to the Board pursuant to the Rule. In its notice, Energy Corp. indicated that it intended to "stimulate" or "chemically treat" the Hunt Creek Well and "perform a diagnostic fracture injection test" (diagnostic test) on the well. The notice provided a detailed description of the planned work and stated that the well would be shut in once "25-30 barrels [had] been pumped into the formation." Pursuant to the Rule, the Board approved Energy Corp.'s notice and allowed it to perform the diagnostic test without engaging in any additional review or public process.

¶8 After the hearing, but prior to Energy Corp.'s submitting notice pursuant to the Rule, Resource Councils challenged the Board's permitting process for the Hunt Creek Well. Resource Councils claimed, in part, that the Board's application of the Rule violated their constitutional right to meaningfully participate in government decisions. On the parties' cross-motions for summary judgment, the District Court held that because hydraulic fracturing had not occurred at the Hunt Creek Well, Resource Councils' constitutional challenge was not ripe for judgment.[2] Resource Councils appeal.

STANDARDS OF REVIEW

¶9 We review summary judgment rulings de novo. *Reichert v. State*, 2012 MT 111, ¶ 18, 365 Mont. 92, 278 P.3d 455. Issues of justiciability—such as standing, mootness, ripeness, and political question—are questions of law that we also review de novo. *Reichert*, ¶ 20. Our review of constitutional questions is plenary. *Williams v. Bd. of Cnty. Comm'rs*, 2013 MT 243, ¶ 23, 371 Mont. 356, 308 P.3d 88.

DISCUSSION

¶10 *1. Whether the District Court erred in concluding that Resource Councils' challenge was not ripe.*

¶11 Relying on *Reichert*, the District Court first concluded that Resource Councils' right to participate claim would be ripe only if Energy Corp. had expanded its drilling permit to include hydraulic fracturing without public input. The court found that Energy Corp.'s diagnostic test did not meet the definition of hydraulic fracturing under Admin. R. M. 36.22.302(28). Thus, the court concluded that Resource Councils' assertion that hydraulic fracturing had occurred at the Hunt Creek Well was "speculation unsupported by any specific facts." The District Court concluded therefore that Resource Councils' right to participate claim was unripe for judgment.

[2] Resource Councils also claimed that the Board acted arbitrarily and capriciously in approving the permit. The District Court granted the Board summary judgment on the issue. Resource Councils do not appeal that holding.

¶12 It is well-established that "the judicial power of Montana's courts is limited to 'justiciable controversies.'" *Reichert*, ¶ 53 (quoting *Plan Helena, Inc. v. Helena Reg'l Airport Auth. Bd.*, 2010 MT 26, ¶ 6, 355 Mont. 142, 226 P.3d 567). A justiciable controversy is, in general terms, "one that is definite and concrete . . . as distinguished from an opinion advising what the law would be upon a hypothetical state of facts, or upon an abstract proposition." *Reichert*, ¶ 53 (citations and internal quotations omitted). Ripeness—which is a specific justiciability doctrine—"is concerned with whether the case presents an 'actual, present' controversy." *Reichert*, ¶ 54 (quoting *Mont. Power Co. v. Mont. Pub. Serv. Comm'n*, 2001 MT 102, ¶ 32, 305 Mont. 260, 26 P.3d 91). As such, "cases are unripe when the parties point only to hypothetical, speculative, or illusory disputes as opposed to actual, concrete conflicts." *Reichert*, ¶ 54 (citations omitted).

¶13 In their amended complaint, Resource Councils asserted that the Rule

> allows a company to proceed with hydro-fracking upon providing the Board's staff certain specified information 48 hours in advance of commencing hydro-fracking. The Board staff is under no obligation to take further action, inform the Board or the public of the fact that hydro-fracking will occur at the [Energy Corp.] well.

They asserted further that no additional "environmental review, public participation or Board deliberation is required under the terms of [the Rule]." Resource Councils argued that the Rule, as applied here, consequently violated their "fundamental right to meaningfully participate in government decisions." Therefore, contrary to the District Court's conclusion, Resource Councils' right to participate claim does not hinge on whether Energy Corp. engaged in hydraulic fracturing at the Hunt Creek Well. Rather, their claim centers on whether they had the opportunity to participate in the permitting process.

¶14 It is undisputed that Energy Corp. filed a sundry notice pursuant to the Rule's procedures, which the Board approved. Therefore, the controversy—whether Resource Councils had the opportunity to participate in the process—was not a "hypothetical, speculative, or illusory dispute[ ]." *Reichert*, ¶ 54. On the contrary, Resource Councils' claim that the Board violated their right to participate in applying the Rule raised "an actual, present controversy" because the Board applied the Rule. *Reichert*, ¶ 54 (citation and internal quotations omitted).

¶15 The District Court erred in concluding that Resource Councils' right to participate claim was unripe. We proceed to consider the claim and its merits.

¶16 *2. Whether the Board violated Resource Councils' right to participate.*

¶17 Resource Councils assert that the Board expanded the original well permit's scope when it approved Energy Corp.'s sundry notice pursuant to the Rule because the notice, not the original application for a permit to drill, "is where the operator discloses a desire to chemically stimulate a well and provides specific information about the proposed activities." As such, Resource Councils assert that the "Board failed to provide adequate notice or meaningful opportunity for public participation in the decision making process" that led to the Board's approving chemical stimulation activities under the Rule. Resource Councils argue that the Board therefore violated their fundamental right to participate under both the Public Participation in Governmental Operations Act, §§ 2-3-101 to 2-3-301, MCA, and Article II, Section 8, of the Montana Constitution.

¶18 Resource Councils acknowledge that the Board provided them an opportunity to participate during the February 2014 hearing on Energy Corp.'s application for a permit to drill the exploratory Hunt Creek Well. They contend, however, that that "hearing cannot suffice as a meaningful opportunity to participate in a decision to chemically stimulate the [Energy Corp.] well" because the Board made clear during the hearing that it was considering only an exploratory well, the permit's environmental assessment did not address hydraulic fracturing, and the Board's decision to approve the exploratory well "did not implicate the concerns of the public" regarding hydraulic fracturing. Moreover, Resource Councils allege, the Board "stated it lacked authority or jurisdiction to consider specific concerns regarding" hydraulic fracturing during the hearing. Finally, Resource Councils contend that hydraulic fracturing at the Hunt Creek Well is a matter of significant public interest and therefore the Board was required to adopt procedures to ensure adequate notice and public participation in the Rule's procedural process, which it failed to do.

¶19 The Board counters that its approval of well stimulation activities pursuant to the Rule was not an expansion of the original drilling permit's scope because well stimulation is allowed under a drilling permit. As such, the Board contends, its rules and procedures ensuring notice and public participation during the permitting process include the well stimulation activities allowed under a drilling permit. The Board contends that the record demonstrates that Resource Councils always knew that well stimulation activities could occur under a drilling permit. The Board and Amicus Montana Petroleum Association also maintain that the diagnostic test did not constitute hydraulic fracturing because the test's purpose was to temporarily test the well's reservoir pressure and did not involve well stimulation.

¶20 The Board argues that Resource Councils had the opportunity to participate in—and did participate in—the Board's decision to approve the drilling permit, which included consideration of the potential for hydraulic fracturing at the Hunt Creek Well. As evidence that Resource Councils "meaningfully participated in the Board's decision," the Board points to the considerable testimony Resource Councils' members and their expert provided during the hearing as well as the fact that the Board approved the permit with the condition that Energy Corp. comply with certain water standards should it engage in hydraulic fracturing. Because Resource Councils participated in the permit approval process—which the Board claims included consideration of well stimulation activities—the Board asserts that providing Resource Councils with an additional opportunity to participate was not required.

¶21 "The essential elements" required to meet Montana's constitutional and statutory guarantees of public participation are "notice and an opportunity to be heard." *Bitterroot River Protective Ass'n v. Bitterroot Conservation Dist.*, 2008 MT 377, ¶ 21, 346 Mont. 507, 198 P.3d 219 (citing § 2-3-103(1)(a), MCA). Public participation procedures "must include a method of affording interested persons reasonable opportunity to submit data, views, or arguments." Section 2-3-111(1), MCA.

¶22 The record demonstrates that Resource Councils had notice not only of the application for a permit to drill, but also of the potential for well stimulation activities at the Hunt Creek Well pursuant to the Rule. Affidavits of Resource Councils' members state explicitly that they received notice of Energy Corp.'s application for a permit to drill. Based on this notice, Resource Councils sent the Board a letter on October 23, 2013, requesting a hearing to discuss their concerns with the proposed permit. The testimony of Resource Councils' members at the hearing focused on the potential negative impacts of hydraulic fracturing at the site. Furthermore, Resource Councils' expert submitted a report that focused, in part, on the risks associated with hydraulic fracturing "[g]iven the likelihood that hydraulic fracturing will take place at the proposed well."

¶23 The record demonstrates further that Resource Councils were given an opportunity to be heard on their concerns about well stimulation activities under the Rule. Although the Board could have declined to hold a hearing due to Resource Councils' procedural problems in objecting to the permit, Admin R. M. 36.22.601(4), the Board held a full hearing on the permit application due, in part, to the "extensive media coverage and public comments received during the public comment period." Resource Councils' members and their expert testified for nearly an hour and a half during the hearing. Their testimony focused on the potential negative environmental impacts associated with hydraulic fracturing at the Hunt Creek Well. The recorded hearing testimony demonstrates that the Board clearly afforded Resource Councils an opportunity "to submit data, views, or arguments" related to well stimulation at the site. Section 2-3-111(1), MCA. Moreover, the Board made clear during the hearing that it retained "the full authority to grant, deny, or grant conditionally the application for a drilling permit." That the Board approved the permit with the condition that Energy Corp. comply with certain water standards should it propose hydraulic fracturing at the Hunt Creek Well in the future demonstrates that Resource Councils were heard on the issue.

¶24 The District Court additionally observed "that the record clearly reflects that the Board has continually guaranteed to [Resource Councils] that [they] will be given the opportunity to weigh in on any [hydraulic fracturing] ventures that might someday be brought forth." During the hearing, the Board's administrator noted that "wastewater and hydraulic fracturing are regulated under the rules [the Board] adopted a couple of years ago. If hydraulic fracturing isn't approved with the drilling permit then there's another process that has to be followed to approve it." The administrator emphasized that "hydraulic fracturing has not been proposed in the permit. The environmental assessment assesses what was proposed, which was a potential horizontal well, but does not propose hydraulic fracturing." In its briefing on appeal, the Board emphatically asserts that hydraulic fracturing has not occurred at the Hunt Creek Well. It does not take issue with the District Court's statement that the Board guaranteed that Resource Councils will be given the opportunity to participate should hydraulic fracturing be proposed at the Hunt Creek Well in the future.

¶25 It is unclear from the record, the Board's briefing, and our review of the pertinent Administrative Rules what process the Board anticipates should Energy Corp. propose hydraulic fracturing at the Hunt Creek Well. The Board's representations, however, demonstrate that it will further consider the matter should Energy Corp. make that proposal, and that it will afford additional process at that time. On this record, we conclude that Resource Councils had notice and an opportunity to participate in the Board's consideration of the permit and to present evidence about their concerns for well stimulation activities at the site. Accordingly—under the facts presented here—the Board did not violate Resource Councils' right to participate.

CONCLUSION

¶26 We reverse the District Court's holding that Resource Councils' right to participate challenge was unripe; however, we conclude that the Board did not violate Resource Councils' right to participate in applying the Rule to the permit it issued for the Hunt Creek Well.

/S/ BETH BAKER

We concur:

/S/ MIKE McGRATH
/S/ MICHAEL E WHEAT
/S/ JAMES JEREMIAH SHEA
/S/ JIM RICE

Chief Justice Mike McGrath, concurring.

¶27 Because of the unique procedural nature of this case, CCRC is left without a resolution on the merits of its constitutional and statutory challenge to the sundry notice and forty-eight-hour provisions of Admin. R. M. 36.22.608.

¶28 The District Court determined that the challenge was not ripe because hydraulic fracturing had not occurred. The majority Opinion, which I have signed, reverses the District Court on ripeness. We conclude that the February 2014 hearing was sufficient to satisfy the right to participate challenges brought regarding the Board's grant of the initial permit to drill, but specifically determine it is unnecessary to decide whether the Board's forty-eight-hour notice rule may be unconstitutional in other circumstances.

¶29 The District Court specifically noted:

> [T]his Court anticipates a claim regarding the constitutionality of Administrative Rules of Montana § 36.22.608(2) may become ripe for adjudication in the future if it is used to expand an APD to include fracking. The Court notes that 48 hours is a short notification period in this developing industry and recognizes that other states have expanded this time frame.

The District Court's anticipation was strongly anchored in the record. Both the administrator and the Board made it clear they were considering a vertical wildcat well and that fracking was not proposed. As the majority notes, the Board does not challenge the District Court's assumption and has continually guaranteed that the plaintiffs will have the opportunity to participate should any "[hydraulic] fracking ventures . . . someday be brought forth."

¶30 The Board asserts in its brief to this Court that hydraulic fracturing has not occurred at, or been proposed for, this well. It is with this understanding that I have signed the majority Opinion. If hydraulic fracturing is proposed for this well, the Board will implement procedure to ensure that the public's right to a meaningful opportunity to participate is protected.

¶31 I concur.

/S/ MIKE McGRATH

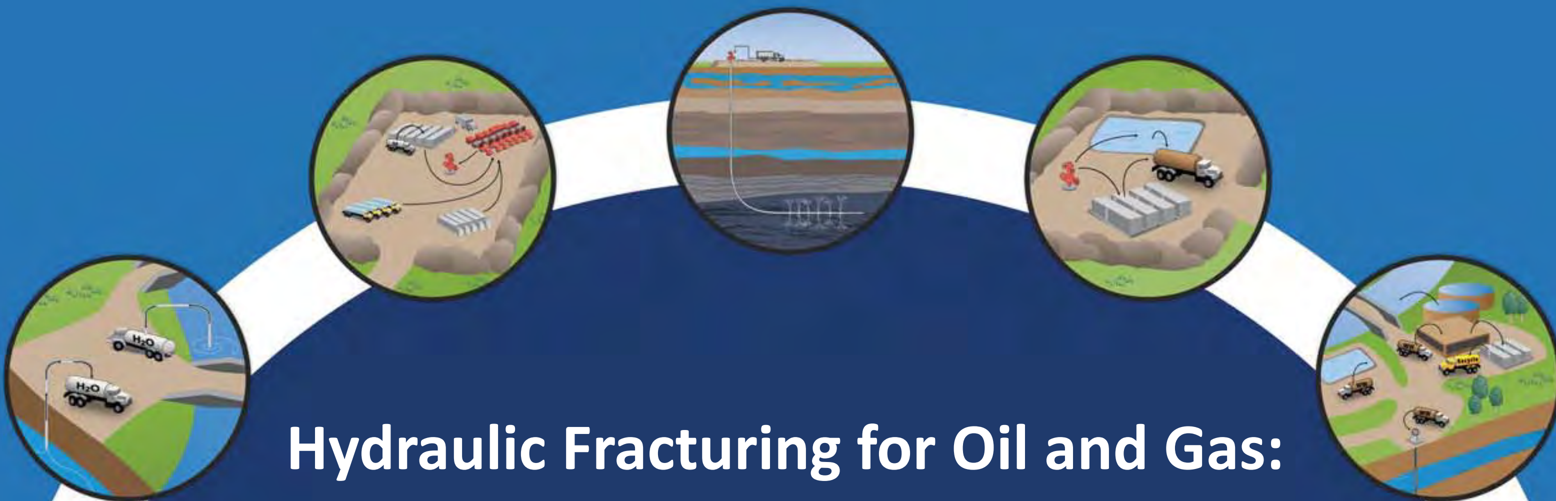
Justices James Jeremiah Shea and Michael E Wheat join the concurring Opinion of Chief Justice Mike McGrath.

/S/ MICHAEL E WHEAT
/S/ JAMES JEREMIAH SHEA

EXHIBIT 2
To Comments Re: Rulemaking on Hydraulic Fracturing Chemical Disclosure

United States Environmental Protection Agency

EPA-600-R-16-236ES
December 2016
www.epa.gov/hfstudy



Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States

Executive Summary

Office of Research and Development
Washington, DC

Aerial photograph of hydraulic fracturing well sites near Williston, North Dakota.
Image ©J Henry Fair / Flights provided by LightHawk

Executive Summary

People rely on clean and plentiful water resources to meet their basic needs, including drinking, bathing, and cooking. In the early 2000s, members of the public began to raise concerns about potential impacts on their drinking water from hydraulic fracturing at nearby oil and gas production wells. In response to these concerns, Congress urged the U.S. Environmental Protection Agency (EPA) to study the relationship between hydraulic fracturing for oil and gas and drinking water in the United States.

The goals of the study were to assess the potential for activities in the hydraulic fracturing water cycle to impact the quality or quantity of drinking water resources and to identify factors that affect the frequency or severity of those impacts. To achieve these goals, the EPA conducted independent research, engaged stakeholders through technical workshops and roundtables, and reviewed approximately 1,200 cited sources of data and information. The data and information gathered through these efforts served as the basis for this report, which represents the culmination of the EPA's study of the potential impacts of hydraulic fracturing for oil and gas on drinking water resources.

The hydraulic fracturing water cycle describes the use of water in hydraulic fracturing, from water withdrawals to make hydraulic fracturing fluids, through the mixing and injection of hydraulic fracturing fluids in oil and gas production wells, to the collection and disposal or reuse of produced water. These activities can impact drinking water resources under some circumstances. Impacts can range in frequency and severity, depending on the combination of hydraulic fracturing water cycle activities and local- or regional-scale factors. The following combinations of activities and factors are more likely than others to result in more frequent or more severe impacts:

- Water withdrawals for hydraulic fracturing in times or areas of low water availability, particularly in areas with limited or declining groundwater resources;

- Spills during the management of hydraulic fracturing fluids and chemicals or produced water that result in large volumes or high concentrations of chemicals reaching groundwater resources;
- Injection of hydraulic fracturing fluids into wells with inadequate mechanical integrity, allowing gases or liquids to move to groundwater resources;
- Injection of hydraulic fracturing fluids directly into groundwater resources;
- Discharge of inadequately treated hydraulic fracturing wastewater to surface water resources; and
- Disposal or storage of hydraulic fracturing wastewater in unlined pits, resulting in contamination of groundwater resources.

The above conclusions are based on cases of identified impacts and other data, information, and analyses presented in this report. Cases of impacts were identified for all stages of the hydraulic fracturing water cycle. Identified impacts generally occurred near hydraulically fractured oil and gas production wells and ranged in severity, from temporary changes in water quality to contamination that made private drinking water wells unusable.

The available data and information allowed us to qualitatively describe factors that affect the frequency or severity of impacts at the local level. However, significant data gaps and uncertainties in the available data prevented us from calculating or estimating the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle. The data gaps and uncertainties described in this report also precluded a full characterization of the severity of impacts.

The scientific information in this report can help inform decisions by federal, state, tribal, and local officials; industry; and communities. In the short-term, attention could be focused on the combinations of activities and factors outlined above. In the longer-term, attention could be focused on reducing the data gaps and uncertainties identified in this report. Through these efforts, current and future drinking water resources can be better protected in areas where hydraulic fracturing is occurring or being considered.

Drinking Water Resources in the United States

In this report, drinking water resources are defined as any water that now serves, or in the future could serve, as a source of drinking water for public or private use. This includes both surface water resources and groundwater resources (Text Box ES-1). In 2010, approximately 58% of the total volume of water withdrawn for public and non-public water supplies came from surface water resources and approximately 42% came from groundwater resources (Maupin et al., 2014).[1] Most people (86% of the population) in the United States relied on public water supplies for their drinking water in 2010, and approximately 14% of the population obtained drinking water from non-public water supplies. Non-public water supplies are often private water wells that supply drinking water to a residence.

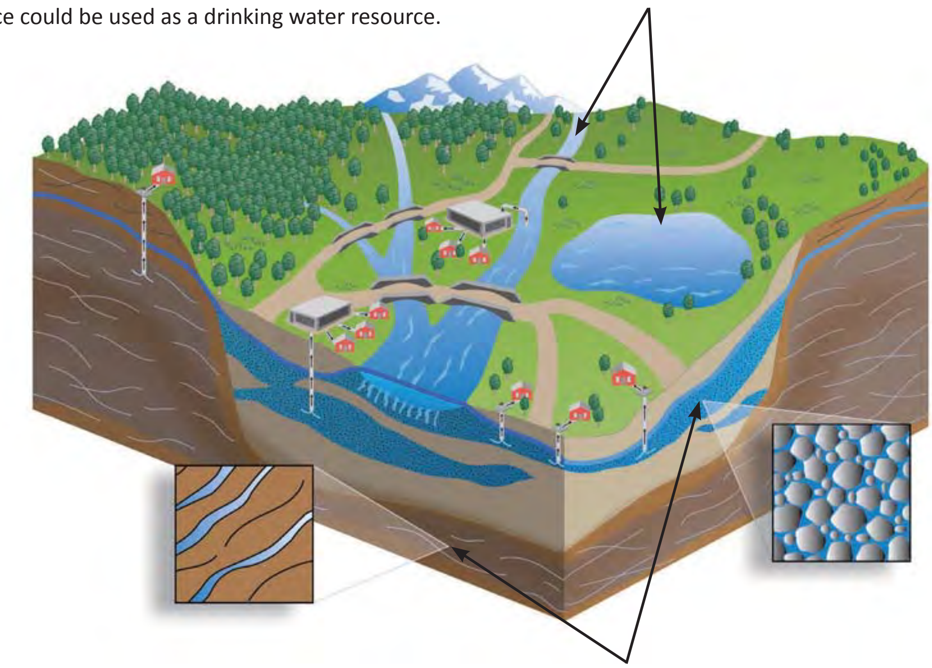
Future access to high-quality drinking water in the United States will likely be affected by changes in climate and water use. Since 2000, about 30% of the total area of the contiguous United States has experienced moderate drought conditions and about 20% has experienced severe drought conditions. Declines in surface water resources have

[1] Public water systems provide water for human consumption from surface or groundwater through pipes or other infrastructure to at least 15 service connections or serve an average of at least 25 people for at least 60 days a year. Non-public water systems have fewer than 15 service connections and serve fewer than 25 individuals.

Text Box ES-1: Drinking Water Resources

In this report, drinking water resources are considered to be any water that now serves, or in the future could serve, as a source of drinking water for public or private use. This includes both surface water bodies and underground rock formations that contain water.

Surface water resources include water bodies located on the surface of the Earth. Rivers, springs, lakes, and reservoirs are examples of surface water resources. Water quality and quantity are often considered when determining whether a surface water resource could be used as a drinking water resource.



Groundwater resources are underground rock formations that contain water. Groundwater resources are found at different depths nearly everywhere in the United States. Resource depth, water quality, and water yield are often considered when determining whether a groundwater resource could be used as a drinking water resource.

led to increased withdrawals and net depletions of groundwater in some areas. As a result, non-fresh water resources (e.g., wastewater from sewage treatment plants, brackish groundwater and surface water, and seawater) are increasingly treated and used to meet drinking water demand.

Natural processes and human activities can affect the quality and quantity of current and future drinking water resources. This report focuses on the potential for activities in the hydraulic fracturing water cycle to impact drinking water resources; other processes or activities are not discussed.

Hydraulic Fracturing for Oil and Gas in the United States

Hydraulic fracturing is frequently used to enhance oil and gas production from underground rock formations and is one of many activities that occur during the life of an oil and gas production well (Figure ES-1). During hydraulic fracturing, hydraulic fracturing fluid is injected down an oil or gas production well and into the targeted rock formation under pressures great enough to fracture the oil- and gas-

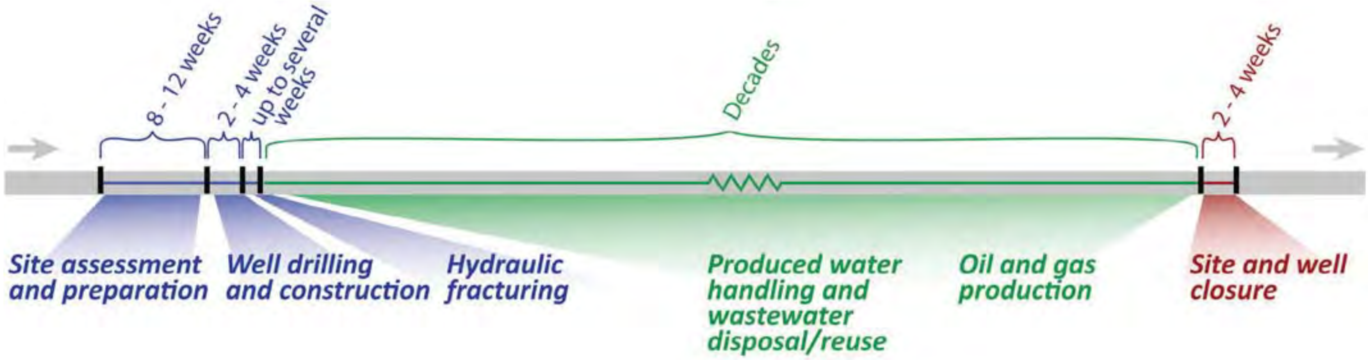


Figure ES-1. General timeline and summary of activities at a hydraulically fractured oil or gas production well.

bearing rock.[1] The hydraulic fracturing fluid usually carries proppant (typically sand) into the newly-created fractures to keep the fractures "propped" open. After hydraulic fracturing, oil, gas, and other fluids flow through the fractures and up the production well to the surface, where they are collected and managed.

Hydraulically fractured oil and gas production wells have significantly contributed to the surge in domestic oil and gas production, accounting for slightly more than 50% of oil production and nearly 70% of gas production in 2015 (EIA, 2016a, b). The surge occurred when hydraulic fracturing was combined with directional drilling technologies around 2000. Directional drilling allows oil and gas production wells to be drilled horizontally or directionally along the targeted rock formation, exposing more of the oil- or gas-bearing rock formation to the production well. When combined with directional drilling technologies, hydraulic fracturing expanded oil and gas production to oil- and gas-bearing rock formations previously considered uneconomical. Although hydraulic fracturing is commonly associated with oil and gas production from deep, horizontal wells drilled into shale (e.g., the Marcellus Shale in Pennsylvania or the Bakken Shale in North Dakota), it has been used in a variety of oil and gas production wells (Text Box ES-2) and other types of oil- or gas-bearing rock (e.g., sandstone, carbonate, and coal).

Approximately 1 million wells have been hydraulically fractured since the technique was first developed in the late 1940s (Gallegos and Varela, 2015; IOGCC, 2002). Roughly one third of those wells were hydraulically fractured between 2000 and approximately 2014. Wells hydraulically fractured between 2000 and 2013 were located in pockets of activity across the United States (Figure ES-2). Based on several different data compilations, we estimate that 25,000 to 30,000 new wells were drilled and hydraulically fractured in the United States each year between 2011 and 2014, in addition to existing wells that were hydraulically fractured to increase production.[2] Following the decline in oil and gas prices, the number of new wells drilled and hydraulically fractured appears to have decreased, with about 20,000 new wells drilled and hydraulically fractured in 2015.

Hydraulically fractured oil and gas production wells can be located near or within sources of drinking water. Between 2000 and 2013, approximately 3,900 public water systems were estimated to have had at least one hydraulically fractured well within 1 mile of their water source; these public water systems served more than 8.6 million people year-round in 2013. An additional 3.6 million people were estimated to have obtained drinking water from non-

[1] The targeted rock formation (sometimes called the "target zone" or "production zone") is the portion of a subsurface rock formation that contains the oil or gas to be extracted.

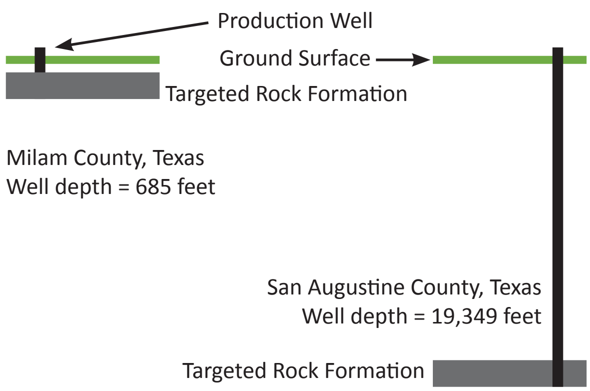
[2] See Table 3-1 in Chapter 3.

Text Box ES-2: Hydraulically Fractured Oil and Gas Production Wells

Hydraulically fractured oil and gas production wells come in different shapes and sizes. They can have different depths, orientations, and construction characteristics. They can include new wells (i.e., wells that are hydraulically fractured soon after construction) and old wells (i.e., wells that are hydraulically fractured after producing oil and gas for some time).

Well Depth

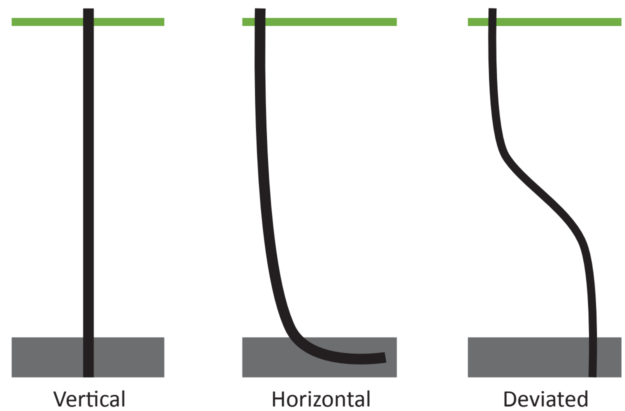
Wells can be relatively shallow or relatively deep, depending on the depth of the targeted rock formation.



Well depths and locations from FracFocus.org.

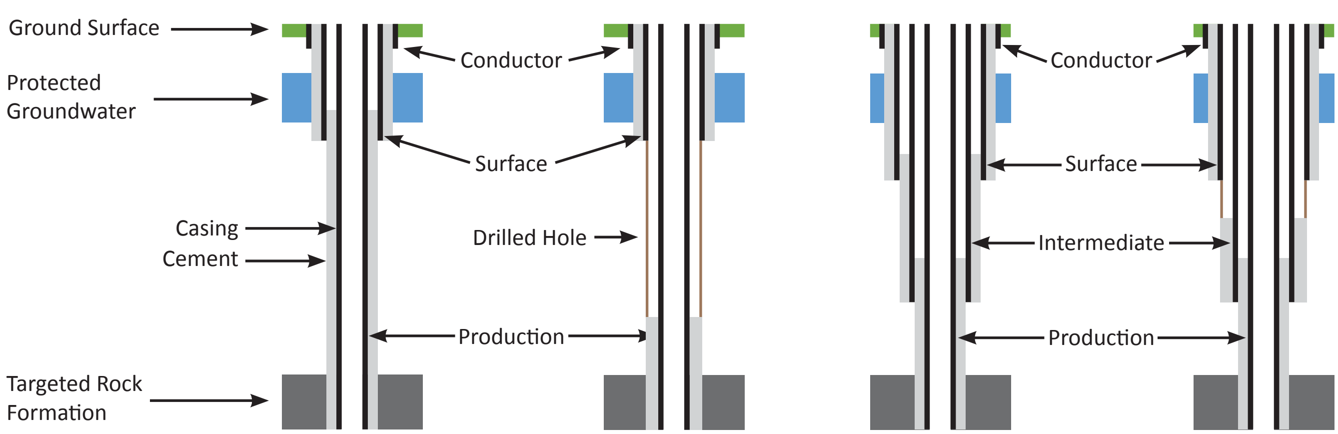
Well Orientation

Wells can be vertical, horizontal, or deviated.



Well Construction Characteristics

Wells are typically constructed using multiple layers of casing and cement. The subsurface environment, state and federal regulations, and industry experience and practices influence the number and placement of casing and cement.



Conductor, surface, and production casings

Conductor, surface, intermediate, and production casings

Well diagrams are not to scale.

Oil and Gas Production Well Dictionary

Casing	Steel pipe that extends from the ground surface to the bottom of the drilled hole
Cement	A slurry that hardens around the outside of the casing; cement fills the space between casings or between a casing and the drilled hole and provides support for the casing
Conductor casing	Casing that prevents the in-fill of dirt and rock in the uppermost few feet of drilled hole
Intermediate casing	Casing that seals off intermediate rock formations that may have different pressures than deeper or shallower rock formations
Production casing	Casing that transports fluids up and down the well
Surface casing	Casing that seals off groundwater resources that are identified as drinking water or useable
Targeted rock formation	The part of a rock formation that contains the oil and/or gas to be extracted

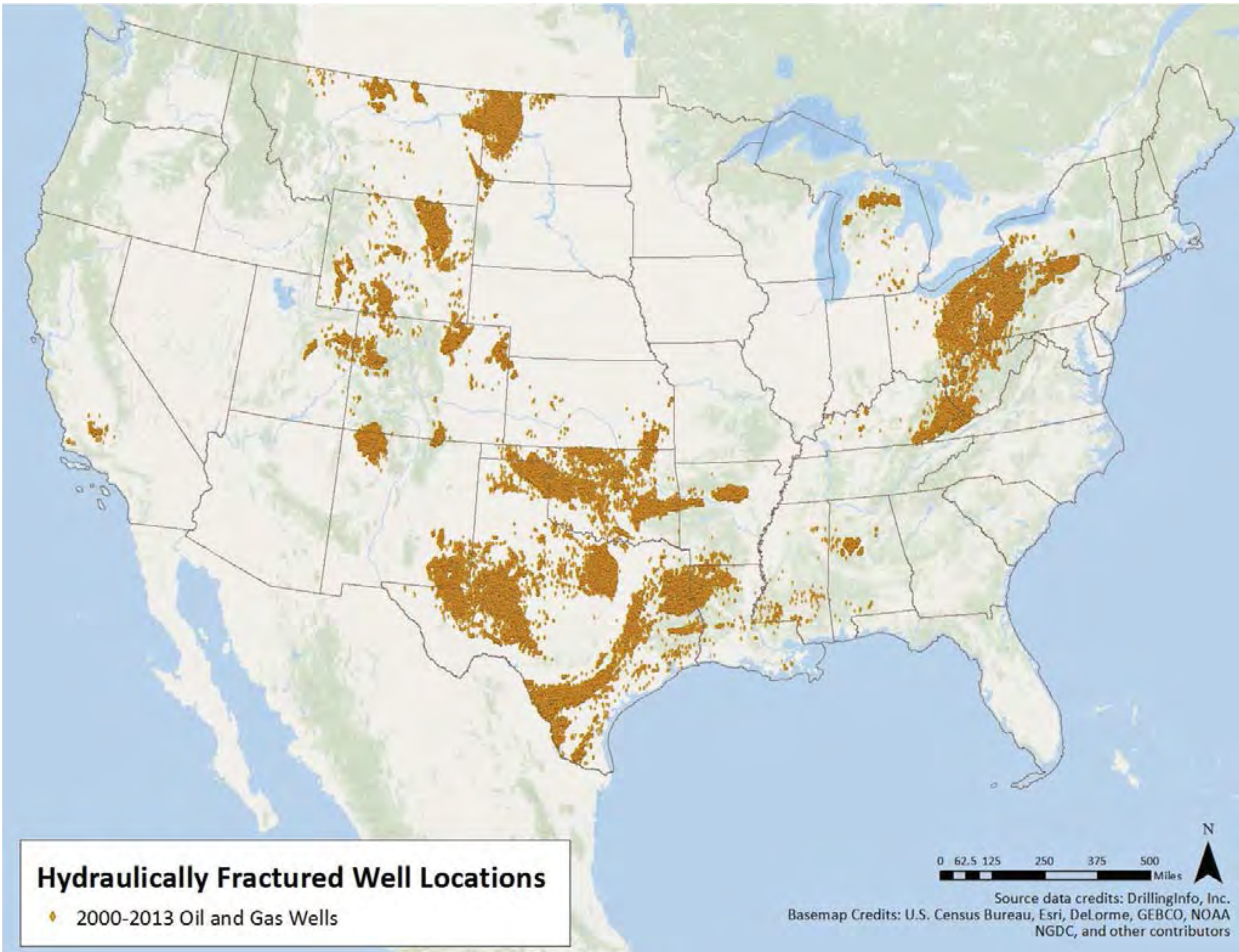


Figure ES-2. Locations of approximately 275,000 wells that were drilled and likely hydraulically fractured between 2000 and 2013. Data from DrillingInfo (2014).

public water supplies in counties with at least one hydraulically fractured well.[1] Underground, hydraulic fracturing can occur in close vertical proximity to drinking water resources. In some parts of the United States (e.g., the Powder River Basin in Montana and Wyoming), there is no vertical distance between the top of the hydraulically fractured oil- or gas-bearing rock formation and the bottom of treatable water, as determined by data from state oil and gas agencies and state geological survey data.[2] In other parts of the country (e.g., the Eagle Ford Shale in Texas), there can be thousands of feet of rock that separate treatable water from the hydraulically fractured oil- or gas-bearing rock formation. When hydraulically fractured oil and gas production wells are located near or within drinking water resources, there is a greater potential for activities in the hydraulic fracturing water cycle to impact those resources.

[1] This estimate only includes counties in which 30% or more of the population (i.e., two or more times the national average) relied on non-public water supplies in 2010. See Section 2.5 in Chapter 2.

[2] In these cases, water that is naturally found in the oil- and gas-bearing rock formation meets the definition of drinking water in some parts of the basin. See Section 6.3.2 in Chapter 6.

Approach: The Hydraulic Fracturing Water Cycle

The EPA studied the relationship between hydraulic fracturing for oil and gas and drinking water resources using the hydraulic fracturing water cycle (Figure ES-3). The hydraulic fracturing water cycle has five stages; each stage is defined by an activity involving water that supports hydraulic fracturing. The stages and activities of the hydraulic fracturing water cycle include:

- **Water Acquisition:** the withdrawal of groundwater or surface water to make hydraulic fracturing fluids;
- **Chemical Mixing:** the mixing of a base fluid (typically water), proppant, and additives at the well site to create hydraulic fracturing fluids;[1]
- **Well Injection:** the injection and movement of hydraulic fracturing fluids through the oil and gas production well and in the targeted rock formation;
- **Produced Water Handling:** the on-site collection and handling of water that returns to the surface after hydraulic fracturing and the transportation of that water for disposal or reuse;[2] and
- **Wastewater Disposal and Reuse:** the disposal and reuse of hydraulic fracturing wastewater.[3]

Potential impacts on drinking water resources from the above activities are considered in this report. We do not address other concerns that have been raised by stakeholders about hydraulic fracturing (e.g., potential air quality impacts or induced seismicity) or other oil and gas exploration and production activities (e.g., environmental impacts from site selection and development), as these were not included in the scope of the study. Additionally, this report is not a human health risk assessment; it does not identify populations exposed to hydraulic fracturing-related chemicals, and it does not estimate the extent of exposure or estimate the incidence of human health impacts.

Each stage of the hydraulic fracturing water cycle was assessed to identify (1) the potential for impacts on drinking water resources and (2) factors that affect the frequency or severity of impacts. Specific definitions used in this report are provided below:

- An **impact** is any change in the quality or quantity of drinking water resources, regardless of severity, that results from an activity in the hydraulic fracturing water cycle.
- A **factor** is a feature of hydraulic fracturing operations or an environmental condition that affects the frequency or severity of impacts.
- **Frequency** is the number of impacts per a given unit (e.g., geographic area, unit of time, number of hydraulically fractured wells, or number of water bodies).
- **Severity** is the magnitude of change in the quality or quantity of a drinking water resource as measured by a given metric (e.g., duration, spatial extent, or contaminant concentration).

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[1] A base fluid is the fluid into which proppants and additives are mixed to make a hydraulic fracturing fluid; water is an example of a base fluid. Additives are chemicals or mixtures of chemicals that are added to the base fluid to change its properties.

[2] "Produced water" is defined in this report as water that flows from and through oil and gas wells to the surface as a by-product of oil and gas production.

[3] "Hydraulic fracturing wastewater" is defined in this report as produced water from hydraulically fractured oil and gas wells that is being managed using practices that include, but are not limited to, injection in Class II wells, reuse in other hydraulic fracturing operations, and various aboveground disposal practices. The term "wastewater" is being used as a general description of certain waters and is not intended to constitute a term of art for legal or regulatory purposes. Class II wells are used to inject wastewater associated with oil and gas production underground and are regulated under the Underground Injection Control Program of the Safe Drinking Water Act.

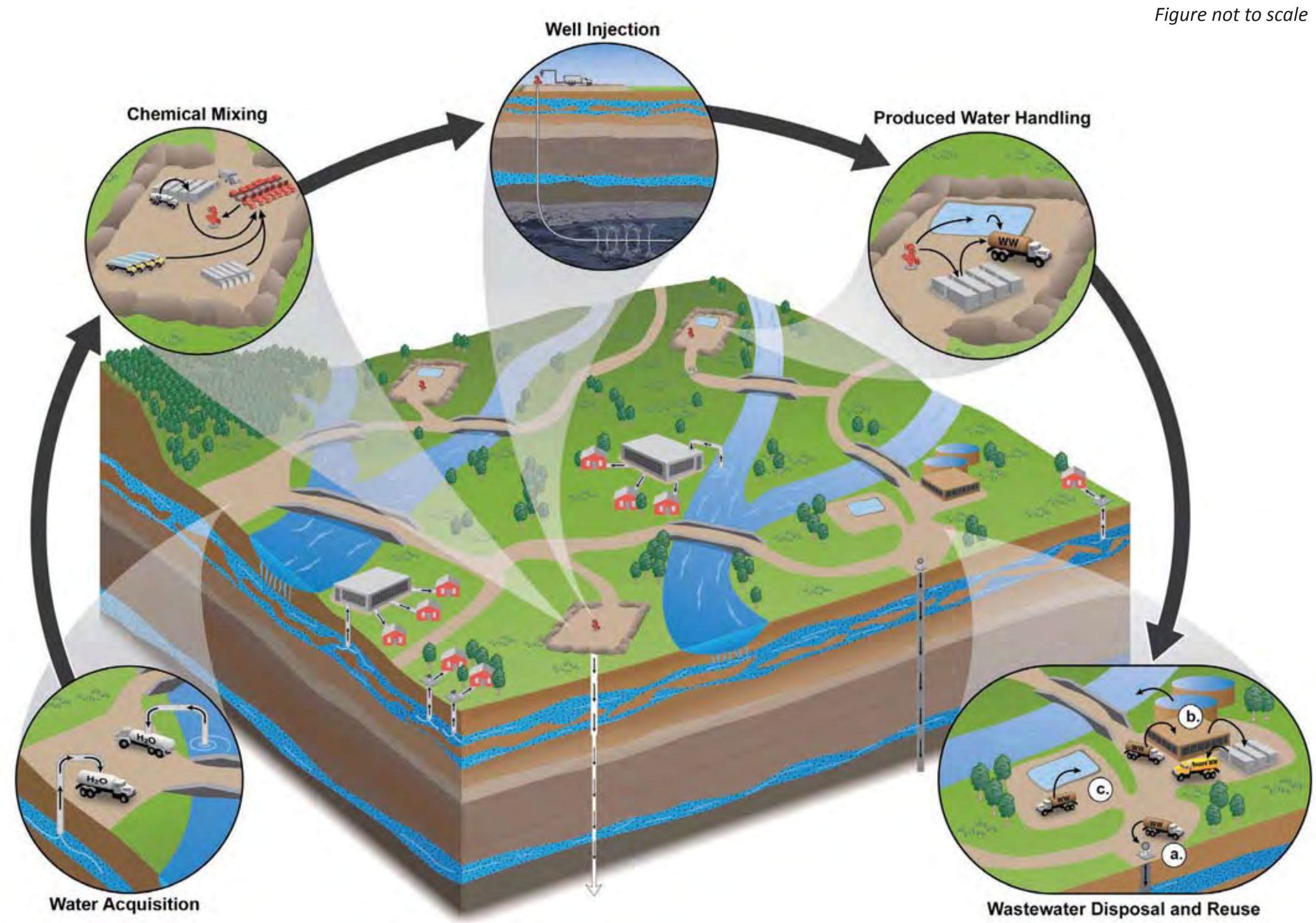


Figure ES-3. The five stages of the hydraulic fracturing water cycle. The stages (shown in the insets) identify activities involving water that support hydraulic fracturing for oil and gas. Activities may take place in the same watershed or different watersheds and close to or far from drinking water resources. Thin arrows in the insets depict the movement of water and chemicals. Specific activities in the "Wastewater Disposal and Reuse" inset include (a) disposal of wastewater through underground injection, (b) wastewater treatment followed by reuse in other hydraulic fracturing operations or discharge to surface waters, and (c) disposal through evaporation or percolation pits.

Factors affecting the frequency or severity of impacts were identified because they describe conditions under which impacts are more or less likely to occur and because they could inform the development of future strategies and actions to prevent or reduce impacts. Although no attempt was made to identify or evaluate best practices, ways to reduce the frequency or severity of impacts from activities in the hydraulic fracturing water cycle are described in this report when they were reported in the scientific literature. Laws, regulations, and policies also exist to protect drinking water resources, but a comprehensive summary and broad evaluation of current or proposed regulations and policies was beyond the scope of this report.

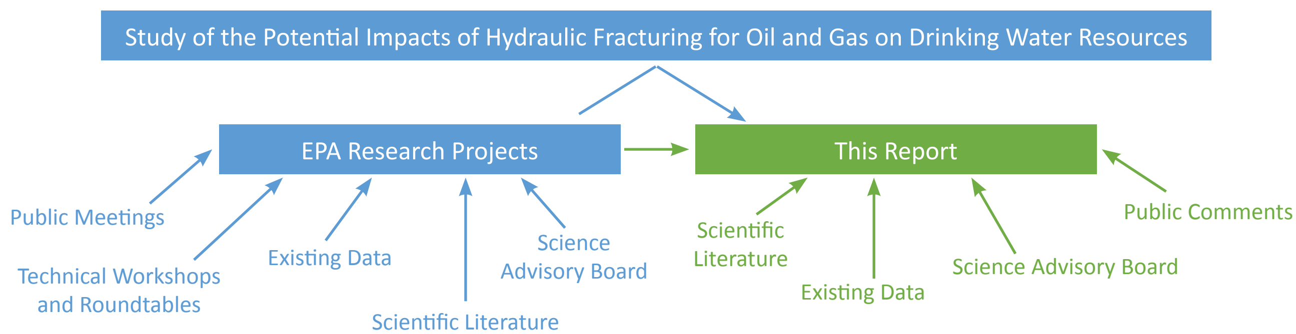
Relevant scientific literature and data were evaluated for each stage of the hydraulic fracturing water cycle. Literature included articles published in science and engineering journals, federal and state government reports, non-governmental organization reports, and industry publications. Data sources included federal- and state-collected data sets, databases maintained by federal and state government agencies, other publicly available data, and industry data provided to the EPA.[1] The relevant literature and data complement research conducted by the EPA under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (Text Box ES-3).

A draft of this report underwent peer review by the EPA's Science Advisory Board (SAB). The SAB is an independent federal advisory committee that often conducts peer reviews of high-profile scientific matters relevant to the EPA. Members of the SAB and *ad hoc* panels formed under the auspices of the SAB are nominated by the public and selected based on factors such as technical expertise, knowledge, experience, and absence of any real or perceived conflicts of interest. Peer review comments provided by the SAB and public comments submitted to the SAB during their peer review, including comments on major conclusions and technical content, were carefully considered in the development of this final document.

A summary of the activities in the hydraulic fracturing water cycle and their potential to impact drinking water resources is provided below, including what is known about human health hazards associated with chemicals identified across all stages of the hydraulic fracturing water cycle. Additional details are available in the full report.

Text Box ES-3: The EPA's *Study of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources*

The EPA's study is the first national study of the potential impacts of hydraulic fracturing for oil and gas on drinking water resources. It included independent research projects conducted by EPA scientists and contractors and a state-of-the-science assessment of available data and information on the relationship between hydraulic fracturing and drinking water resources (i.e., this report).



Throughout the study, the EPA consulted with the Agency's independent Science Advisory Board (SAB) on the scope of the study and the progress made on the research projects. The SAB also conducted a peer review of both the *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (U.S. EPA, 2011; referred to as the *Study Plan* in this report) and a draft of this report.

Stakeholder engagement also played an important role in the development and implementation of the study. While developing the scope of the study, the EPA held public meetings to get input from stakeholders on the study scope and design. While conducting the study, the EPA requested information from the public and engaged with technical, subject-matter experts on topics relevant to the study in a series of technical workshops and roundtables. For more information on the EPA's study, including the role of the SAB and stakeholders, visit www.epa.gov/hfstudy.

[1] Industry data was provided to the EPA in response to two separate information requests to oil and gas service companies and oil and gas production well operators. Some of these data were claimed as confidential business information under the Toxic Substances Control Act and were treated as such in this report.

Water Acquisition

The withdrawal of groundwater or surface water to make hydraulic fracturing fluids.

<u>Relationship to Drinking Water Resources</u>

Groundwater and surface water resources that provide water for hydraulic fracturing fluids can also provide drinking water for public or non-public water supplies.

Water is the major component of nearly all hydraulic fracturing fluids, typically making up 90–97% of the total fluid volume injected into a well. The median volume of water used, per well, for hydraulic fracturing was approximately 1.5 million gallons (5.7 million liters) between January 2011 and February 2013, as reported in FracFocus 1.0 (Text Box ES-4). There was wide variation in the water volumes reported per well, with 10th and 90th percentiles of 74,000 gallons (280,000 liters) and 6 million gallons (23 million liters) per well, respectively. There was also variation in water use per well within and among states (Table ES-1). This variation likely results from several factors, including the type of well, the fracture design, and the type of hydraulic fracturing fluid used. An analysis of hydraulic fracturing fluid data from Gallegos et al. (2015) indicates that water volumes used per well have increased over time as more horizontal wells have been drilled.

Water used for hydraulic fracturing is typically fresh water taken from available groundwater and/or surface water resources located near hydraulically fractured oil and gas production wells. Water sources can vary across the United States, depending on regional or local water availability; laws, regulations, and policies; and water management practices. Hydraulic fracturing operations in the humid eastern United States generally rely on surface water

Text Box ES-4: FracFocus Chemical Disclosure Registry

The FracFocus Chemical Disclosure Registry is a publicly-accessible website (www.fracfocus.org) managed by the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC). Oil and gas production well operators can disclose information at this website about water and chemicals used in hydraulic fracturing fluids at individual wells. In many states where oil and gas production occurs, well operators are required to disclose to FracFocus well-specific information on water and chemical use during hydraulic fracturing.

The GWPC and the IOGCC provided the EPA with over 39,000 PDF disclosures submitted by well operators to FracFocus (version 1.0) before March 1, 2013. Data in the disclosures were extracted and compiled in a project database, which was used to conduct analyses on water and chemical use for hydraulic fracturing. Analyses were conducted on over 38,000 unique disclosures for wells located in 20 states that were hydraulically fractured between January 1, 2011, and February 28, 2013.

Despite the challenge of adapting a dataset originally created for local use and single-PDF viewing to answer broader questions, the project database created by the EPA provided substantial insight into water and chemical use for hydraulic fracturing. The project database represents the data reported to FracFocus 1.0 rather than all hydraulic fracturing that occurred in the United States during the study time period. The project database is an incomplete picture of all hydraulic fracturing due to voluntary reporting in some states for certain time periods (in the absence of state reporting requirements), the omission of information on confidential chemicals from disclosures, and invalid or erroneous information in the original disclosures or created during the development of the database. The development of FracFocus 2.0, which became the exclusive reporting mechanism in June 2013, was intended to increase the quality, completeness, and consistency of the data submitted by providing dropdown menus, warning and error messages during submission, and automatic formatting of certain fields. The GWPC has announced additional changes and upgrades for FracFocus 3.0 to enhance data searchability, increase system security, provide greater data accuracy, and further increase data transparency.

Table ES-1. Water use per hydraulically fractured well between January 2011 and February 2013. Medians and percentiles were calculated from data submitted to FracFocus 1.0 (Appendix B).

State	Number of FracFocus 1.0 Disclosures	Median Volume per Well (gallons)	10th percentile (gallons)	90th percentile (gallons)
Arkansas	1,423	5,259,965	3,234,963	7,121,249
California	711	76,818	21,462	285,306
Colorado	4,898	463,462	147,353	3,092,024
Kansas	121	1,453,788	10,836	2,227,926
Louisiana	966	5,077,863	1,812,099	7,945,630
Montana	207	1,455,757	367,326	2,997,552
New Mexico	1,145	175,241	35,638	1,871,666
North Dakota	2,109	2,022,380	969,380	3,313,482
Ohio	146	3,887,499	2,885,568	5,571,027
Oklahoma	1,783	2,591,778	1,260,906	7,402,230
Pennsylvania	2,445	4,184,936	2,313,649	6,615,981
Texas	16,882	1,420,613	58,709	6,115,195
Utah	1,406	302,075	76,286	769,360
West Virginia	273	5,012,238	3,170,210	7,297,080
Wyoming	1,405	322,793	5,727	1,837,602

resources, whereas operations in the arid and semi-arid western United States generally rely on groundwater or surface water. Geographic differences in water use for hydraulic fracturing are illustrated in Figure ES-4, which shows that most of the water used for hydraulic fracturing in the Marcellus Shale region of the Susquehanna River Basin came from surface water resources between approximately 2008 and 2013. In comparison, less than half of the water used for hydraulic fracturing in the Barnett Shale region of Texas came from surface water resources between approximately 2011 and 2013.

Hydraulic fracturing wastewater and other lower-quality water can also be used in hydraulic fracturing fluids to offset the need for fresh water, although the proportion of injected fluid that is reused hydraulic fracturing wastewater varies by location (Figure ES-4).[1] Overall, the proportion of water used in hydraulic fracturing that comes from reused hydraulic fracturing wastewater appears to be low. In a survey of literature values from 10 states, basins, or plays, the median percentage of the injected fluid volume that came from reused hydraulic fracturing wastewater was 5% between approximately 2008 and 2014.[2] There was an increase in the reuse of hydraulic fracturing wastewater as a percentage of the injected hydraulic fracturing fluid in both Pennsylvania and West Virginia between approximately 2008 and 2014. This increase is likely due to the limited availability of Class II wells, which are commonly used to dispose of oil and gas wastewater, and the costs of trucking wastewater to Ohio, where Class II wells are

[1] Reused hydraulic fracturing wastewater as a percentage of injected fluid differs from the percentage of produced water that is managed through reuse in other hydraulic fracturing operations. For example, in the Marcellus Shale region of the Susquehanna River Basin, approximately 14% of injected fluid was reused hydraulic fracturing wastewater, while approximately 90% of produced water was managed through reuse in other hydraulic fracturing operations (Figure ES-4a).

[2] See Section 4.2 in Chapter 4.

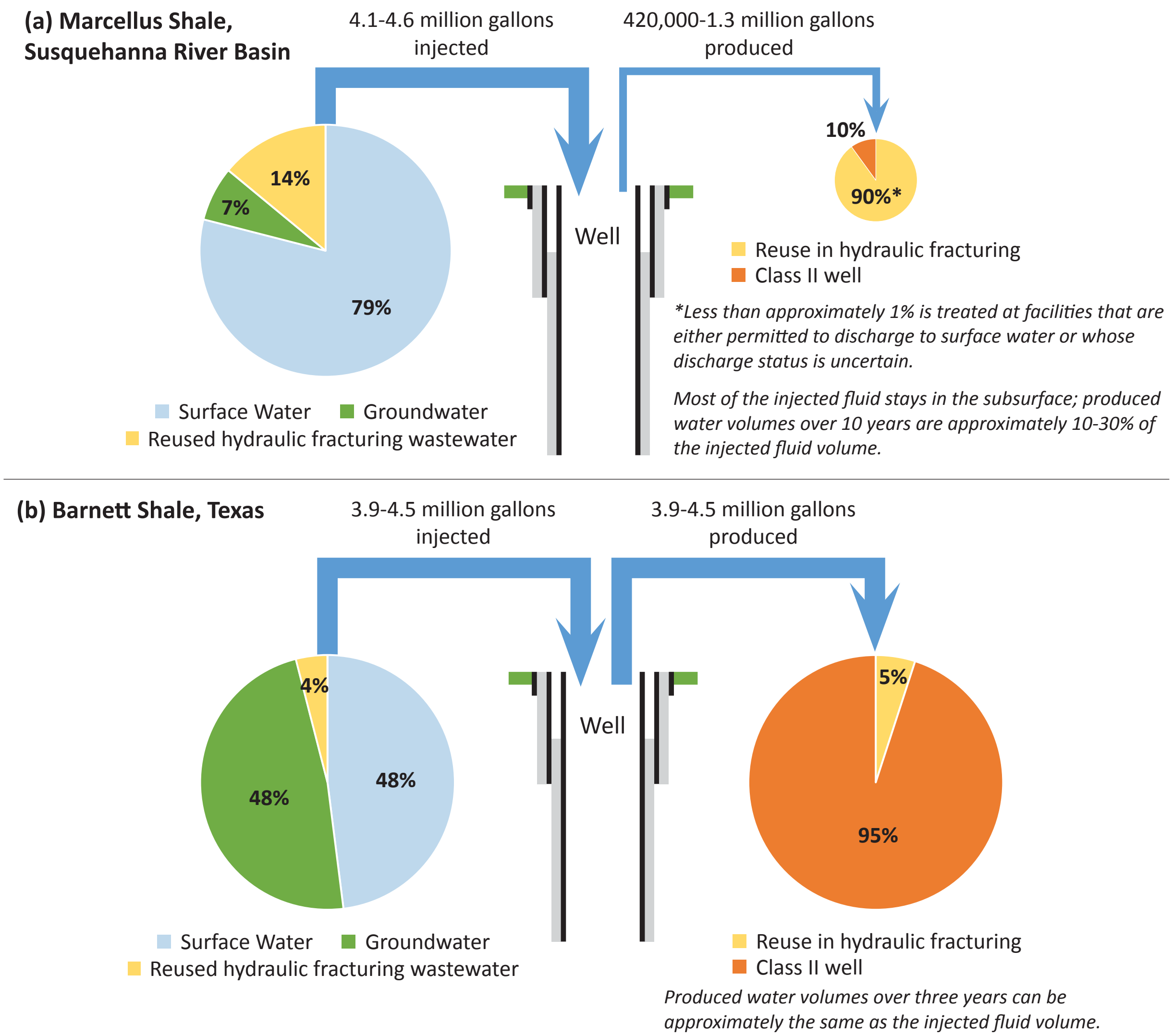


Figure ES-4. Water budgets illustrative of hydraulic fracturing water management practices in (a) the Marcellus Shale in the Susquehanna River Basin between approximately 2008 and 2013 and (b) the Barnett Shale in Texas between approximately 2011 and 2013. Class II wells are used to inject wastewater associated with oil and gas production underground and are regulated under the Underground Injection Control Program of the Safe Drinking Water Act. Data sources are described in Figure 10-1 in Chapter 10.

more prevalent.[1] Class II wells are also prevalent in Texas, and the reuse of wastewater in hydraulic fracturing fluids in the Barnett Shale appears to be lower than in the Marcellus Shale (Figure ES-4).

Because the same water resource can be used to support hydraulic fracturing and to provide drinking water, withdrawals for hydraulic fracturing can directly impact drinking water resources by changing the quantity or quality of the remaining water. Although every water withdrawal affects water quantity, we focused on water withdrawals that have the potential to significantly impact drinking water re-

[1] See Chapter 8 for additional information on Class II wells.

sources by limiting the availability of drinking water or altering its quality. Water withdrawals for a single hydraulically fractured oil and gas production well are not expected to significantly impact drinking water resources, because the volume of water needed to hydraulically fracture a single well is unlikely to limit the availability of drinking water or alter its quality. If, however, multiple oil and gas production wells are located within an area, the total volume of water needed to hydraulically fracture all of the wells has the potential to be a significant portion of the water available and impacts on drinking water resources can occur.

To assess whether hydraulic fracturing operations are a relatively large or small user of water, we compared water use for hydraulic fracturing to total water use at the county level (Text Box ES-5). In most counties studied, the average annual water volumes reported in FracFocus 1.0 were generally less than 1% of total water use. This suggests that hydraulic fracturing operations represented a relatively small user of water in most counties. There were exceptions, however. Average annual water volumes reported in FracFocus 1.0 were 10% or more of total water use in 26 of the 401 counties studied, 30% or more in nine counties, and 50% or more in four counties.[1] In these counties, hydraulic fracturing operations represented a relatively large user of water.

The above results suggest that hydraulic fracturing operations can significantly increase the volume of water withdrawn in particular areas. Increased water withdrawals can result in significant impacts on drinking water resources if there is insufficient water available in the area to accommodate all users. To assess the potential for these impacts, we compared hydraulic fracturing water use to estimates of water availability at the county level.[2] In most counties studied, average annual water volumes reported for hydraulic fracturing were less than 1% of the estimated annual volume of readily-available fresh water. However, average annual water volumes reported for hydraulic fracturing were greater than the estimated annual volume of readily-available fresh water in 17 counties in Texas. This analysis suggests that there was enough water available annually to support the level of hydraulic fracturing reported to FracFocus 1.0 in most, but not all, areas of the country. This observation does not preclude the possibility of local impacts in other areas of the country, nor does it indicate that local impacts have occurred or will occur in the 17 counties in Texas. To better understand whether local impacts have occurred, and the factors that affect those impacts, local-level studies, such as the ones described below, are needed.

Local impacts on drinking water quantity have occurred in areas with increased hydraulic fracturing activity. In 2011, for example, drinking water wells in an area overlying the Haynesville Shale ran out of water due to higher than normal groundwater withdrawals and drought (Louisiana Ground Water Resources Commission, 2012). Water withdrawals for hydraulic fracturing contributed to these conditions, along with other water users and the lack of precipitation. Groundwater impacts have also been reported in Texas. In a detailed case study, Scanlon et al. (2014) estimated that groundwater levels in approximately 6% of the area studied dropped by 100 feet (31 meters) to 200 feet (61 meters) or more after hydraulic fracturing activity increased in 2009.

In contrast, studies in the Upper Colorado and Susquehanna River basins found minimal impacts on drinking water resources from hydraulic fracturing. In the Upper Colorado River Basin, the EPA found that high-quality water produced from oil and gas wells in the Piceance tight sands provided nearly all of the water for hydraulic fracturing in the study area (U.S. EPA,

[1] Hydraulic fracturing water consumption estimates followed the same general pattern as the water use estimates presented here, but with slightly larger percentages in each category (Section 4.4 in Chapter 4).

[2] County-level water availability estimates were derived from the Tidwell et al. (2013) estimates of water availability for siting new thermoelectric power plants (see Text Box 4-2 in Chapter 4 for details). The county-level water availability estimates used in this report represent the portion of water available to new users within a county.

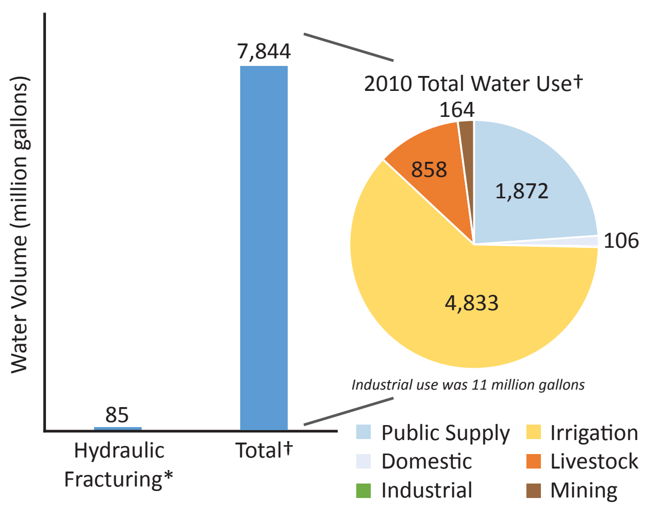
Text Box ES-5: County-Level Water Use for Hydraulic Fracturing

To assess whether hydraulic fracturing operations are a relatively large or small user of water, the average annual water use for hydraulic fracturing in 2011 and 2012 was compared, at the county-level, to total water use in 2010.

For most counties studied, average annual water volumes reported for individual counties in FracFocus 1.0 were less than 1% of total water use in those counties. But in some counties, hydraulic fracturing operations reported in FracFocus 1.0 represented a relatively large user of water.

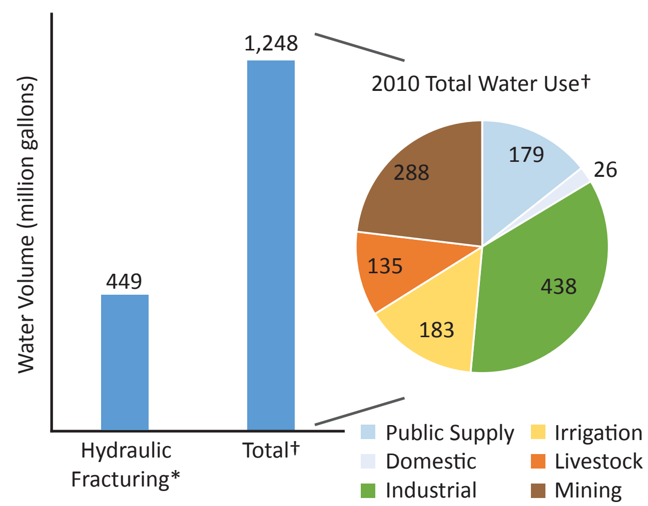
Examples of Water Use in Two Counties: Wilson County, Texas, and Mountrail County, North Dakota

Wilson County, Texas
44 wells reported in FracFocus 1.0



Depending on local water availability, hydraulic fracturing water withdrawals may be **less likely** to significantly impact drinking water resources under this kind of scenario.

Mountrail County, North Dakota
508 wells reported in FracFocus 1.0



Depending on local water availability, hydraulic fracturing water withdrawals may be **more likely** to significantly impact drinking water resources under this kind of scenario.

*Hydraulic fracturing water use is a function of the water use per well and the total number of wells hydraulically fractured within a county. Average annual water use for hydraulic fracturing was calculated at the county-level using data reported in FracFocus 1.0 in 2011 and 2012 (Appendix B).

†The U.S. Geological Survey compiles national water use estimates every five years in the National Water Census. Total water use at the county-level was obtained from the most recent census, which was conducted in 2010 (Maupin et al., 2014).

2010 Total Water Use Categories

Public supply	Water withdrawn by public and private water suppliers that provide water to at least 25 people or have a minimum of 15 connections
Domestic	Self-supplied water withdrawals for indoor household purposes such as drinking, food preparation, bathing, washing clothes and dishes, flushing toilets, and outdoor purposes such as watering lawns and gardens
Industrial	Water used for fabrication, processing, washing, and cooling
Irrigation	Water that is applied by an irrigation system to assist crop and pasture growth or to maintain vegetation on recreational lands (e.g., parks and golf courses)
Livestock	Water used for livestock watering, feedlots, dairy operations, and other on-farm needs
Mining	Water used for the extraction of naturally-occurring minerals, including solids (e.g., coal, sand, gravel, and other ores), liquids (e.g., crude petroleum), and gases (e.g., natural gas)

2015b). Due to this high reuse rate, the EPA did not identify any locations in the study area where hydraulic fracturing contributed to locally high water use. In the Susquehanna River Basin, multiple studies and state reports have identified the potential for hydraulic fracturing water withdrawals in the Marcellus Shale to impact surface water resources. Evidence suggests, however, that current water management strategies, including passby flows and reuse of hydraulic fracturing wastewater, help protect streams from depletion by hydraulic fracturing water withdrawals. A passby flow is a prescribed, low-streamflow threshold below which water withdrawals are not allowed.

The above examples highlight factors that can affect the frequency or severity of impacts on drinking water resources from hydraulic fracturing water withdrawals. In particular, areas of the United States that rely on declining groundwater resources are vulnerable to more frequent and more severe impacts from all water withdrawals, including withdrawals for hydraulic fracturing. Extensive groundwater withdrawals can limit the availability of belowground drinking water resources and can also change the quality of the water remaining in the resource. Because groundwater recharge rates can be low, impacts can last for many years. Seasonal or long-term drought can also make impacts more frequent and more severe for groundwater and surface water resources. Hot, dry weather reduces or prevents groundwater recharge and depletes surface water bodies, while water demand often increases simultaneously (e.g., for irrigation). This combination of factors—high hydraulic fracturing water use and relatively low water availability due to declining groundwater resources and/or frequent drought—was found to be present in southern and western Texas.

Water management strategies can also affect the frequency and severity of impacts on drinking water resources from hydraulic fracturing water withdrawals. These strategies include using hydraulic fracturing wastewater or brackish groundwater for hydraulic fracturing, transitioning from limited groundwater resources to more abundant surface water resources, and using passby flows to control water withdrawals from surface water resources. Examples of these water management strategies can be found throughout the United States. In western and southern Texas, for example, the use of brackish water is currently reducing impacts on fresh water sources, and could, if increased, reduce future impacts. Louisiana and North Dakota have encouraged well operators to withdraw water from surface water resources instead of high-quality groundwater resources. And, as described above, the Susquehanna River Basin Commission limits surface water withdrawals during periods of low stream flow.

Water Acquisition Conclusions

With notable exceptions, hydraulic fracturing uses a relatively small percentage of water when compared to total water use and availability at large geographic scales. Despite this, hydraulic fracturing water withdrawals can affect the quantity and quality of drinking water resources by changing the balance between the demand on local water resources and the availability of those resources. Changes that have the potential to limit the availability of drinking water or alter its quality are more likely to occur in areas with relatively high hydraulic fracturing water withdrawals and low water availability, particularly due to limited or declining groundwater resources. Water management strategies (e.g., encouragement of alternative water sources or water withdrawal restrictions) can reduce the frequency or severity of impacts on drinking water resources from hydraulic fracturing water withdrawals.

Chemical Mixing

The mixing of a base fluid, proppant, and additives at the well site to create hydraulic fracturing fluids.

Relationship to Drinking Water Resources

Spills of additives and hydraulic fracturing fluids can reach groundwater and surface water resources.

Hydraulic fracturing fluids are engineered to create and grow fractures in the targeted rock formation and to carry proppant through the oil and gas production well into the newly-created fractures. Hydraulic fracturing fluids are typically made up of base fluids, proppant, and additives. Base fluids make up the largest proportion of hydraulic fracturing fluids by volume. As illustrated in Text Box ES-6, base fluids can be a single substance (e.g., water in the slickwater example) or can be a mixture of substances (e.g., water and nitrogen in the energized fluid example). The EPA's analysis of hydraulic fracturing fluid data reported to FracFocus 1.0 suggests that water was the most commonly used base fluid between January 2011 and February 2013 (U.S. EPA, 2015a). Non-water substances, such as gases and hydrocarbon liquids, were reported to be used alone or blended with water to form a base fluid in fewer than 3% of wells in FracFocus 1.0.

Proppant makes up the second largest proportion of hydraulic fracturing fluids (Text Box ES-6). Sand (i.e., quartz) was the most commonly reported proppant between January 2011 and February 2013, with 98% of wells in FracFocus 1.0 reporting sand as the proppant (U.S. EPA, 2015a). Other proppants can include man-made or specially engineered particles, such as high-strength ceramic materials or sintered bauxite.[1]

Additives generally make up the smallest proportion of the overall composition of hydraulic fracturing fluids (Text Box ES-6), yet have the greatest potential to impact the quality of drinking water resources compared to proppant and base fluids. Additives, which can be a single chemical or a mixture of chemicals, are added to the base fluid to change its properties (e.g., adjust pH, increase fluid thickness, or limit bacterial growth). The choice of which additives to use depends on the characteristics of the targeted rock formation (e.g., rock type, temperature, and pressure), the economics and availability of desired additives, and well operator or service company preferences and experience.

The variability of additives, both in their purpose and chemical composition, suggests that a large number of different chemicals may be used in hydraulic fracturing fluids across the United States. The EPA identified 1,084 chemicals that were reported to have been used in hydraulic fracturing fluids between 2005 and 2013.[2,3] The EPA's analysis of FracFocus 1.0 data indicates that between 4 and 28 chemicals were used per well between January 2011 and February 2013 and that no single chemical was used in all wells (U.S. EPA, 2015a). Three chemicals—methanol, hydrotreated light petroleum distillates, and hydro-

[1] Sintered bauxite is crushed and powdered bauxite that is fused into spherical beads at high temperatures.

[2] This list includes 1,084 unique Chemical Abstracts Service Registration Numbers (CASRNs), which can be assigned to a single chemical (e.g., hydrochloric acid) or a mixture of chemicals (e.g., hydrotreated light petroleum distillates). Throughout this report, we refer to the substances identified by unique CASRNs as "chemicals."

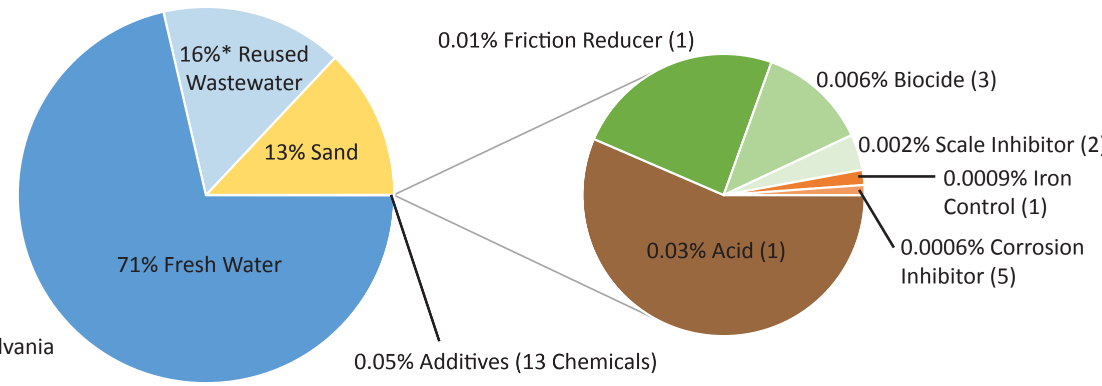
[3] Dayalu and Konschnik (2016) identified 995 unique CASRNs from data submitted to FracFocus between March 9, 2011, and April 13, 2015. Two hundred sixty-three of these CASRNs are not on the list of unique CASRNs identified by the EPA (Appendix H). Only one of the 263 chemicals was reported at greater than 1% of wells, which suggests that these chemicals were used at only a few sites.

Text Box ES-6: Examples of Hydraulic Fracturing Fluids

Hydraulic fracturing fluids are engineered to create and extend fractures in the targeted rock formation and to carry proppant through the production well into the newly-created fractures. While there is no universal hydraulic fracturing fluid, there are general types of hydraulic fracturing fluids. Two types of hydraulic fracturing fluids are described below.

Slickwater

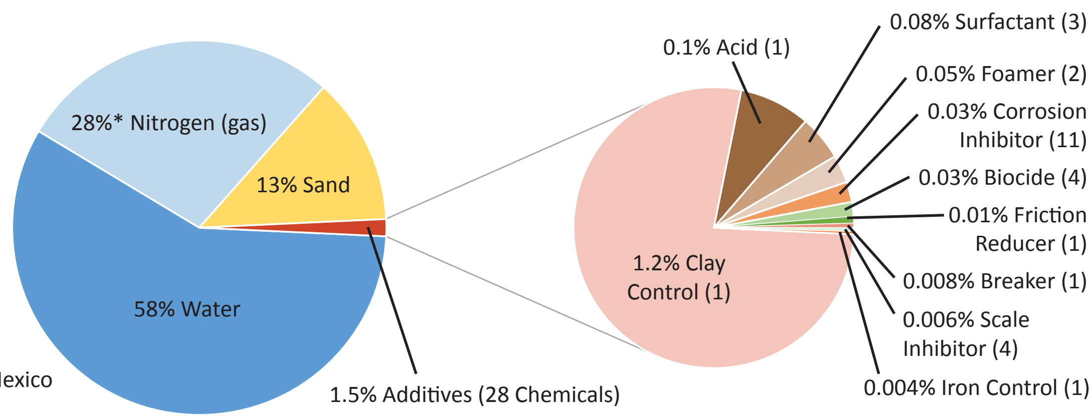
Slickwater hydraulic fracturing fluids are water-based fluids that generally contain a friction reducer. The friction reducer makes it easier for the fluid to be pumped down the oil and gas production well at high rates. Slickwater is commonly used to hydraulically fracture shale formations.



Bradford County, Pennsylvania
Well depth = 7,255 feet
Total water volume = 4,763,000 gallons

Energized Fluid

Energized fluids are mixtures of liquids and gases. They can be used for hydraulic fracturing in under-pressured gas formations.



Rio Arriba County, New Mexico
Well depth = 7,640 feet
Total water volume = 105,000 gallons

**Maximum percent by mass of the total hydraulic fracturing fluid. Data obtained from FracFocus.org.*

Additive Dictionary

Acid	Dissolves minerals and creates pre-fractures in the rock
Biocide	Controls or eliminates bacteria in the hydraulic fracturing fluid
Breaker	Reduces the thickness of the hydraulic fracturing fluid
Clay control	Prevents swelling and migration of formation clays
Corrosion inhibitor	Protects iron and steel equipment from rusting
Foamer	Creates a foam hydraulic fracturing fluid
Friction reducer	Reduces friction between the hydraulic fracturing fluid and pipes during pumping
Iron control	Prevents the precipitation of iron-containing chemicals
Scale inhibitor	Prevents the formation of scale buildup within the well
Surfactant	Reduces the surface tension of the hydraulic fracturing fluid

Table ES-2. Chemicals reported in 10% or more of disclosures in FracFocus 1.0. Disclosures provided information on chemicals used at individual well sites between January 1, 2011, and February 28, 2013.

Chemical Name (CASRN)[a]	Percent of FracFocus 1.0 Disclosures[b]
Methanol (67-56-1)	72
Hydrotreated light petroleum distillates (64742-47-8)	65
Hydrochloric acid (7647-01-0)	65
Water (7732-18-5)[c]	48
Isopropanol (67-63-0)	47
Ethylene glycol (107-21-1)	46
Peroxydisulfuric acid, diammonium salt (7727-54-0)	44
Sodium hydroxide (1310-73-2)	39
Guar gum (9000-30-0)	37
Quartz (14808-60-7)[c]	36
Glutaraldehyde (111-30-8)	34
Propargyl alcohol (107-19-7)	33
Potassium hydroxide (1310-58-3)	29
Ethanol (64-17-5)	29
Acetic acid (64-19-7)	24
Citric acid (77-92-9)	24
2-Butoxyethanol (111-76-2)	21
Sodium chloride (7647-14-5)	21
Solvent naphtha, petroleum, heavy aromatic (64742-94-5)	21

Chemical Name (CASRN)[a]	Percent of FracFocus 1.0 Disclosures[b]
Naphthalene (91-20-3)	19
2,2-Dibromo-3-nitrilopropionamide (10222-01-2)	16
Phenolic resin (9003-35-4)	14
Choline chloride (67-48-1)	14
Methenamine (100-97-0)	14
Carbonic acid, dipotassium salt (584-08-7)	13
1,2,4-Trimethylbenzene (95-63-6)	13
Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides (68424-85-1)	12
Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy (mixture) (127087-87-0)	12
Formic acid (64-18-6)	12
Sodium chlorite (7758-19-2)	11
Nonyl phenol ethoxylate (9016-45-9)	11
Tetrakis(hydroxymethyl)phosphonium sulfate (55566-30-8)	11
Polyethylene glycol (25322-68-3)	11
Ammonium chloride (12125-02-9)	10
Sodium persulfate (7775-27-1)	10

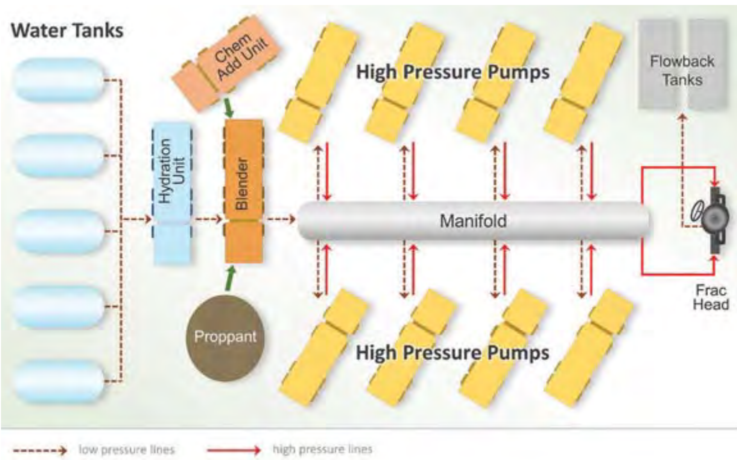
[a] "Chemical" refers to chemical substances with a single CASRN; these may be pure chemicals (e.g., methanol) or chemical mixtures (e.g., hydrotreated light petroleum distillates).
[b] Analysis considered 34,675 disclosures that met selected quality assurance criteria. See Table 5-2 in Chapter 5.
[c] Quartz and water were reported as ingredients in additives, in addition to proppants and base fluids.

chloric acid—were reported in 65% or more of the wells in FracFocus 1.0; 35 chemicals were reported in at least 10% of the wells (Table ES-2).

Concentrated additives are delivered to the well site and stored until they are mixed with the base fluid and proppant and pumped down the oil and gas production well (Text Box ES-7). While the overall concentration of additives in hydraulic fracturing fluids is generally small (typically 2% or less of the total volume of the injected fluid), the total volume of additives delivered to the well site can be large. Because over 1 million gallons (3.8 million liters) of hydraulic fracturing fluid are generally injected per well, thousands of gallons of additives can be stored on site and used during hydraulic fracturing.

As illustrated in Text Box ES-7, additives are often stored in multiple, closed containers [typically 200 gallons (760 liters) to 375 gallons (1,420 liters) per container] and moved around the site in hoses and tubing. This equipment is designed to contain additives and blended hydraulic fracturing fluid, but spills can occur. Changes in drinking water quality can occur if spilled fluids reach groundwater or surface water resources.

Text Box ES-7: Chemical Mixing Equipment



Source: Adapted from Olson (2011) and BJ Services Company (2009)

Typical Layout of Chemical Mixing Equipment

This illustration shows how the different pieces of equipment fit together to contain, mix, and inject hydraulic fracturing fluid into a production well.

Water, proppant, and additives are blended together and pumped to the manifold, where high pressure pumps transfer the fluid to the frac head.

Additives and proppant can be blended with water at different times and in different amounts during hydraulic fracturing. Thus, the composition of hydraulic fracturing fluids can vary during the hydraulic fracturing job.

Well Pad During Hydraulic Fracturing

Equipment set up for hydraulic fracturing.

Source: Schlumberger

Chemical Mixing Equipment Dictionary

Blender	Blends water, proppant, and additives
Chemical additive unit	Transports additives to the site and stores additives onsite
Flowback tanks	Stores liquid that returns to the surface after hydraulic fracturing
Frac head	Connects hydraulic fracturing equipment to the production well
High pressure pumps	Pressurize mixed fluids before injection into the production well
Hydration unit	Creates and stores gels used in some hydraulic fracturing fluids
Manifold	Transfers fluids from the blender to the frac head
Proppant	Stores proppant (often sand)
Water tanks	Stores water

Several studies have documented spills of hydraulic fracturing fluids or additives. Nearly all of these studies identified spills from state-managed spill databases. Data gathered for these studies suggest that spills of hydraulic fracturing fluids or additives were primarily caused by equipment failure or human error. For example, an EPA analysis of spill reports from nine state agencies, nine oil and gas well operators, and nine hydraulic fracturing service companies characterized 151 spills of hydraulic fracturing fluids or additives on or near well sites in 11 states between January 2006 and April 2012 (U.S. EPA, 2015c). These spills were primarily caused by equipment failure (34% of the spills) or human error (25%), and more than 30% of the spills were from fluid storage units (e.g., tanks, totes, and trailers). Similarly, a study of spills reported to the Colorado Oil and Gas Conservation Commission identified 125 spills during well stimulation (i.e., a part of the life of an oil and gas well that often, but not always, includes hydraulic fracturing) between January 2010 and August 2013 (COGCC, 2014). Of these spills, 51% were caused by human error and 46% were due to equipment failure.

Studies of spills of hydraulic fracturing fluids or additives provide insights on spill volumes, but little information on chemical-specific spill composition. Among the 151 spills characterized by the EPA, the median volume of fluid spilled was 420 gallons (1,600 liters), although the volumes spilled ranged from 5 gallons (19 liters) to 19,320 gallons (73,130 liters). Spilled fluids were often described as acids, biocides, friction reducers, crosslinkers, gels, and blended hydraulic fracturing fluid, but few specific chemicals were mentioned.[1] Considine et al. (2012) identified spills related to oil and gas development in the Marcellus Shale that occurred between January 2008 and August 2011 from Notices of Violations issued by the Pennsylvania Department of Environmental Protection. The authors identified spills greater than 400 gallons (1,500 liters) and spills less than 400 gallons (1,500 liters).

Spills of hydraulic fracturing fluids or additives have reached, and therefore impacted, surface water resources. Thirteen of the 151 spills characterized by the EPA were reported to have reached a surface water body (often creeks or streams). Among the 13 spills, reported spill volumes ranged from 28 gallons (105 liters) to 7,350 gallons (27,800 liters). Additionally, Brantley et al. (2014) and Considine et al. (2012) identified fewer than 10 total instances of spills of additives and/or hydraulic fracturing fluids greater than 400 gallons (1,500 liters) that reached surface waters in Pennsylvania between January 2008 and June 2013. Reported spill volumes for these spills ranged from 3,400 gallons (13,000 liters) to 227,000 gallons (859,000 liters).

Although impacts on surface water resources have been documented, site-specific studies that could be used to describe factors that affect the frequency or severity of impacts were not available. In the absence of such studies, we relied on fundamental scientific principles to identify factors that affect how hydraulic fracturing fluids and chemicals can move through the environment to drinking water resources. Because these factors influence whether spilled fluids reach groundwater and surface water resources, they affect the frequency and severity of impacts on drinking water resources from spills during the chemical mixing stage of the hydraulic fracturing water cycle.

The potential for spilled fluids to impact groundwater or surface water resources depends on the characteristics of the spill, the environmental fate and transport of the spilled fluid, and spill response activities (Figure ES-5). Site-specific characteristics affect how spilled liquids move through soil into the subsurface or over the land surface. Generally, highly permeable soils or fractured rock can allow spilled liquids to move quickly into and through the subsurface, limiting the opportunity for spilled liquids to move over land to surface water resources. In low permeability soils, spilled liquids are less able to move into the subsurface and are more likely to move over the

[1] A crosslinker is an additive that increases the thickness of gelled fluids by connecting polymer molecules in the gelled fluid.

land surface. In either case, the volume spilled and the distance between the location of the spill and nearby water resources affects whether spilled liquids reach drinking water resources. Large-volume spills are generally more likely to reach drinking water resources because they are more likely to be able to travel the distance between the location of the spill and nearby water resources.

In general, chemical and physical properties, which depend on the identity and structure of a chemical, control whether spilled chemicals evaporate, stick to soil particles, or move with water. The EPA identified measured or estimated chemical and physical properties for 455 of the 1,084 chemicals used in hydraulic fracturing fluids between 2005 and 2013.[1] The properties of these chemicals varied

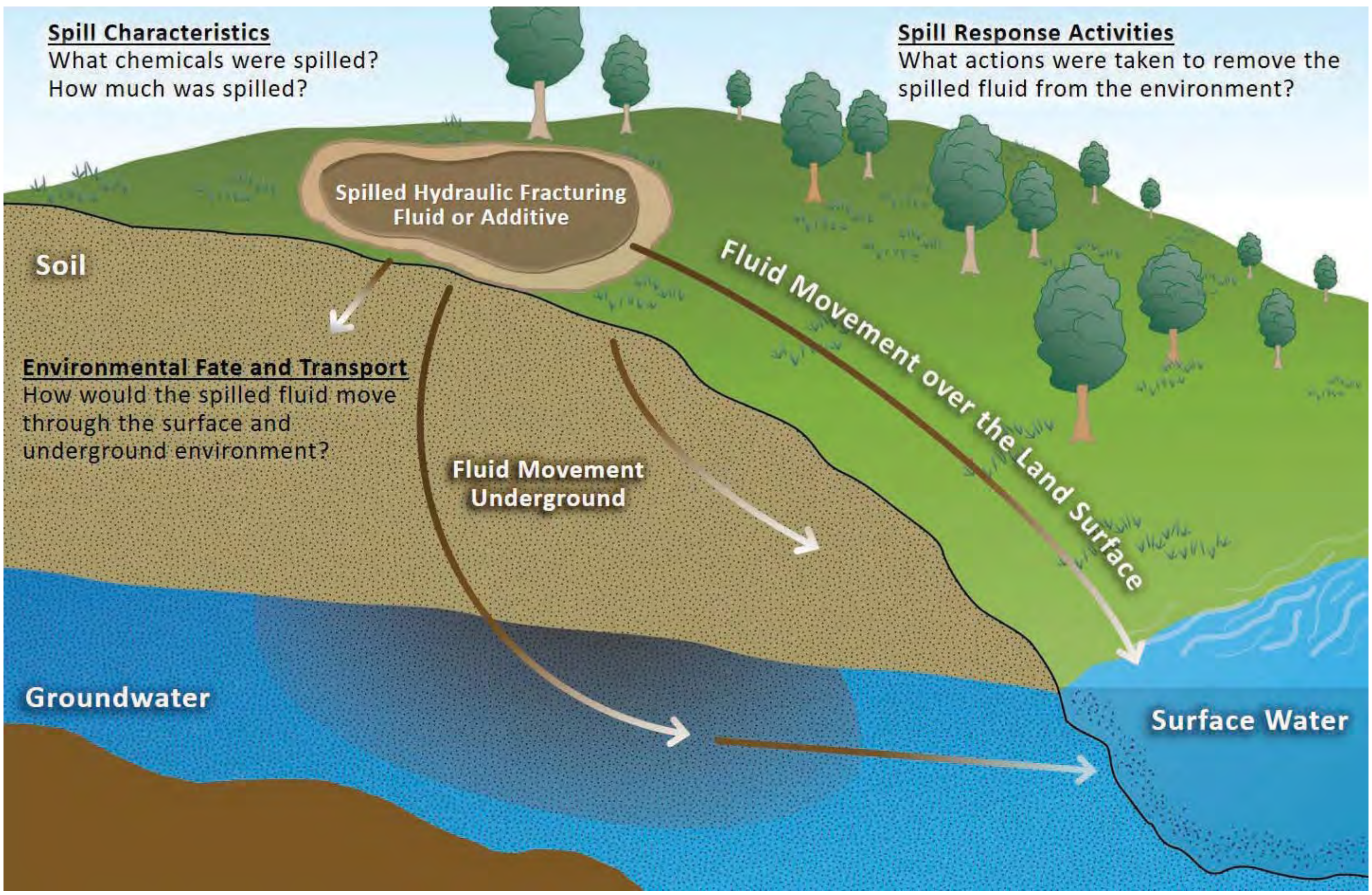


Figure ES-5. Generalized depiction of factors that influence whether spilled hydraulic fracturing fluids or additives reach drinking water resources, including spill characteristics, environmental fate and transport, and spill response activities.

[1] Chemical and physical properties were identified using EPI Suite™. EPI Suite™ is a collection of chemical and physical property and environmental fate estimation programs developed by the EPA and Syracuse Research Corporation. It can be used to estimate chemical and physical properties of individual organic compounds. Of the 1,084 hydraulic fracturing fluid chemicals identified by the EPA, 629 were not individual organic compounds, and thus EPI Suite™ could not be used to estimate their chemical and physical properties.

widely, from chemicals that are more likely to move quickly through the environment with a spilled liquid to chemicals that are more likely to move slowly through the environment because they stick to soil particles.[1] Chemicals that move slowly through the environment may act as longer-term sources of contamination if spilled.

Spill prevention practices and spill response activities are designed to prevent spilled fluids from reaching groundwater or surface water resources and minimize impacts from spilled fluids. Spill prevention and response activities are influenced by federal, state, and local regulations and company practices. Spill prevention practices include secondary containment systems (e.g., liners and berms), which are designed to contain spilled fluids and prevent them from reaching soil, groundwater, or surface water. Spill response activities include activities taken to stop the spill, contain spilled fluids (e.g., the deployment of emergency containment systems), and clean up spilled fluids (e.g., removal of contaminated soil). It was beyond the scope of this report to evaluate the implementation and efficacy of spill prevention practices and spill response activities.

The severity of impacts on water quality from spills of hydraulic fracturing fluids or additives depends on the identity and amount of chemicals that reach groundwater or surface water resources, the toxicity of the chemicals, and the characteristics of the receiving water resource.[2] Characteristics of the receiving groundwater or surface water resource (e.g., water resource size and flow rate) can affect the magnitude and duration of impacts by reducing the concentration of spilled chemicals in a drinking water resource. Impacts on groundwater resources have the potential to be more severe than impacts on surface water resources because it takes longer to naturally reduce the concentration of chemicals in groundwater and because it is generally difficult to remove chemicals from groundwater resources. Due to a lack of data, particularly in terms of groundwater monitoring after spill events, little is publicly known about the severity of drinking water impacts from spills of hydraulic fracturing fluids or additives.

Chemical Mixing Conclusions

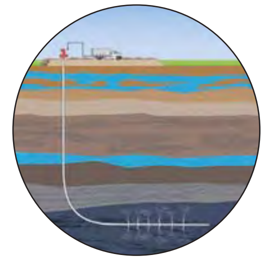
Spills of hydraulic fracturing fluids and additives during the chemical mixing stage of the hydraulic fracturing water cycle have reached surface water resources in some cases and have the potential to reach groundwater resources. Although the available data indicate that spills of various volumes can reach surface water resources, large volume spills are more likely to travel longer distances to nearby groundwater or surface water resources. Consequently, large volume spills likely increase the frequency of impacts on drinking water resources. Large volume spills, particularly of concentrated additives, are also likely to result in more severe impacts on drinking water resources than small volume spills because they can deliver a large quantity of potentially hazardous chemicals to groundwater or surface water resources. Impacts on groundwater resources are likely to be more severe than impacts on surface water resources because of the inherent characteristics of groundwater. Spill prevention and response activities are designed to prevent spilled fluids from reaching groundwater or surface water resources and minimize impacts from spilled fluids.

[1] These results describe how some hydraulic fracturing chemicals behave in infinitely dilute aqueous solutions, which is a simplified approximation of the real-world mixtures found in hydraulic fracturing fluids. The presence of other chemicals in a mixture can affect the fate and transport of a chemical.

[2] Human health hazards associated with hydraulic fracturing fluid chemicals are discussed in Chapter 9 and summarized in the "Chemicals in the Hydraulic Fracturing Water Cycle" section below.

Well Injection

The injection and movement of hydraulic fracturing fluids through the oil and gas production well and in the targeted rock formation.



Relationship to Drinking Water Resources

Belowground pathways, including the production well itself and newly-created fractures, can allow hydraulic fracturing fluids or other fluids to reach underground drinking water resources.

Hydraulic fracturing fluids primarily move along two pathways during the well injection stage: the oil and gas production well and the newly-created fracture network. Oil and gas production wells are designed and constructed to move fluids to and from the targeted rock formation without leaking and to prevent fluid movement along the outside of the well. This is generally accomplished by installing multiple layers of casing and cement within the drilled hole (Text Box ES-2), particularly where the well intersects oil-, gas-, and/or water-bearing rock formations. Casing and cement, in addition to other well components (e.g., packers), can control hydraulic fracturing fluid movement by creating a preferred flow pathway (i.e., inside the casing) and preventing unintentional fluid movement (e.g., from the inside of the casing to the surrounding environment or vertically along the well from the targeted rock formation to shallower formations).[1] An EPA survey of oil and gas production wells hydraulically fractured between approximately September 2009 and September 2010 suggests that hydraulically fractured wells are often, but not always, constructed with multiple casings that have varying amounts of cement surrounding each casing (U.S. EPA, 2015d). Among the wells surveyed, the most common number of casings per well was two: surface casing and production casing (Text Box ES-2). The presence of multiple cemented casings that extend from the ground surface to below the designated drinking water resource is one of the primary well construction features that protects underground drinking water resources.

During hydraulic fracturing, a well is subjected to greater pressure and temperature changes than during any other activity in the life of the well. As hydraulic fracturing fluid is injected into the well, the pressure applied to the well increases until the targeted rock formation fractures; then pressure decreases. Maximum pressures applied to wells during hydraulic fracturing have been reported to range from less than 2,000 pounds per square inch (psi) [14 megapascals (MPa)] to approximately 12,000 psi (83 MPa).[2] A well can also experience temperature changes as cooler hydraulic fracturing fluid enters the warmer well. In some cases, casing temperatures have been observed to drop from 212°F (100°C) to 64°F (18°C). A well can experience multiple pressure and temperature cycles if hydraulic fracturing is done in multiple stages or if a well is re-fractured.[3] Casing, cement, and other well components need to be able to withstand these changes in pressure and temperature, so that hydraulic fracturing fluids can flow to the targeted rock formation without leaking.

The fracture network created during hydraulic fracturing is the other primary pathway along

[1] Packers are mechanical devices installed with casing. Once the casing is set in the drilled hole, packers swell to fill the space between the outside of the casing and the surrounding rock or casing.

[2] For comparison, average atmospheric pressure is approximately 15 psi.

[3] In a multi-stage hydraulic fracturing operation, specific parts of the well are isolated and hydraulically fractured until the total desired length of the well has been hydraulically fractured.

which hydraulic fracturing fluids move. Fracture growth during hydraulic fracturing is complex and depends on the characteristics of the targeted rock formation and the characteristics of the hydraulic fracturing operation. In general, rock characteristics, particularly the natural stresses placed on the targeted rock formation due to the weight of the rock above, affect how the rock fractures, including whether newly-created fractures grow vertically (i.e., perpendicular to the ground surface) or horizontally (i.e., parallel to the ground surface) (Text Box ES-8). Because hydraulic fracturing fluids are used to create and grow fractures, fracture growth during hydraulic fracturing can be controlled by limiting the rate and volume of hydraulic fracturing fluid injected into the well.

Publicly available data on fracture growth are currently limited to microseismic and tiltmeter data collected during hydraulic fracturing operations in five shale plays in the United States. Analyses of these data by Fisher and Warpinski (2012) and Davies et al. (2012) indicate that the direction of fracture growth generally varied with depth and that upward vertical fracture growth was often on the order of tens to hundreds of feet in the shale formations studied (Text Box ES-8). One percent of the fractures had a fracture height greater than 1,148 feet (350 meters), and the maximum fracture height among all of the data reported was 1,929 feet (588 meters). These reported fracture heights suggest that some fractures can grow out of the targeted rock formation and into an overlying formation. It is unknown whether these observations apply to other hydraulically fractured rock formations because similar data from hydraulic fracturing operations in other rock formations are not currently available to the public.

The potential for hydraulic fracturing fluids to reach, and therefore impact, underground drinking water resources is related to the pathways along which hydraulic fracturing fluids primarily move during hydraulic fracturing: the oil and gas production well itself and the fracture network created during hydraulic fracturing. Because the well can be a pathway for fluid movement, the mechanical integrity of the well is an important factor that affects the frequency and severity of impacts from the well injection stage of the hydraulic fracturing water cycle.[1] A well with insufficient mechanical integrity can allow unintended fluid movement, either from the inside to the outside of the well (pathway 1 in Figure ES-6) or vertically along the outside of the well (pathways 2-5). The existence of one or more of these pathways can result in impacts on drinking water resources if hydraulic fracturing fluids reach groundwater resources. Impacts on drinking water resources can also occur if gases or liquids released from the targeted rock formation or other formations during hydraulic fracturing travel along these pathways to groundwater resources.

The pathways shown in Figure ES-6 can exist because of inadequate well design or construction (e.g., incomplete cement around the casing where the well intersects with water-, oil-, or gas-bearing formations) or can develop over the well's lifetime, including during hydraulic fracturing. In particular, casing and cement can degrade over the life of the well because of exposure to corrosive chemicals, formation stresses, and operational stresses (e.g., pressure and temperature changes during hydraulic fracturing). As a result, some hydraulically fractured oil and gas production wells may develop one or more of the pathways shown in Figure ES-6. Changes in mechanical integrity over time have implications for older wells that are hydraulically fractured because these wells may not be able to withstand the stresses applied during hydraulic fracturing. Older wells may also be hydraulically fractured at shallower depths, where cement around the casing may be inadequate or missing.

Examples of mechanical integrity problems have been documented in hydraulically fractured oil and gas production wells. In one case, hydraulic

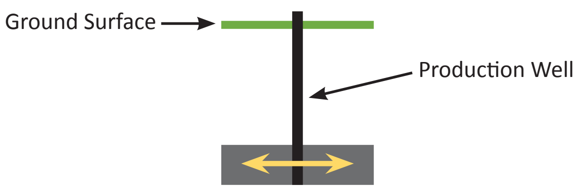
[1] Mechanical integrity is the absence of significant leakage within or outside of the well components.

Text Box ES-8: Fracture Growth

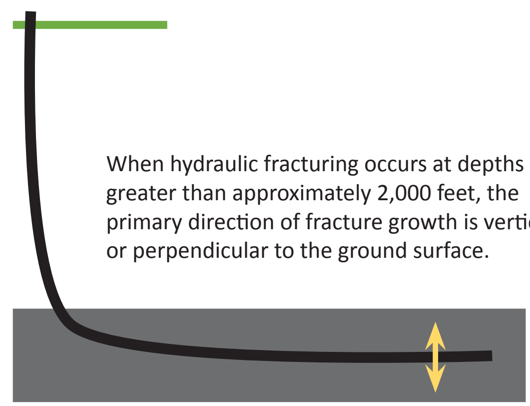
Fracture growth during hydraulic fracturing is complex and depends on the characteristics of the targeted rock formation and the characteristics of the hydraulic fracturing operation.

Primary Direction of Fracture Growth

In general, the weight of the rock above the point of hydraulic fracturing affects the primary direction of fracture growth. Therefore, the depth at which hydraulic fracturing occurs affects whether fractures grow vertically or horizontally.



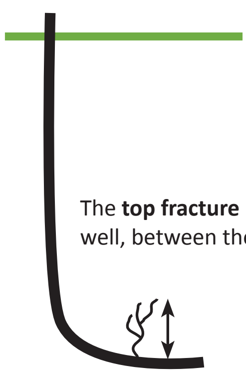
When hydraulic fracturing occurs at depths less than approximately 2,000 feet, the primary direction of fracture growth is horizontal, or parallel to the ground surface.



When hydraulic fracturing occurs at depths greater than approximately 2,000 feet, the primary direction of fracture growth is vertical, or perpendicular to the ground surface.

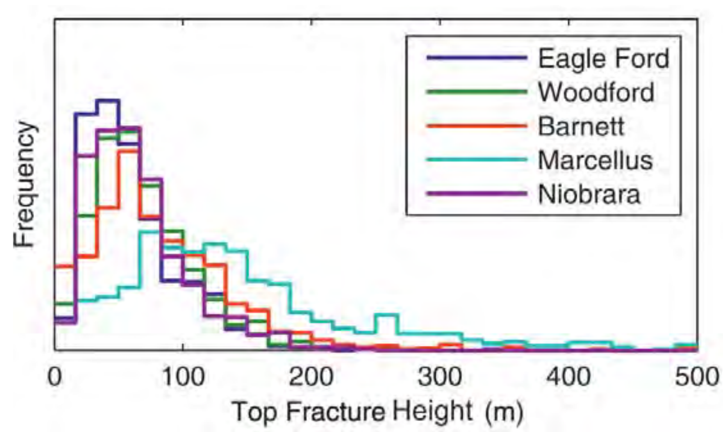
Fracture Height

Fisher and Warpinski (2012) and Davies et al. (2012) analyzed microseismic and tiltmeter data collected during thousands of hydraulic fracturing operations in the Barnett, Eagle Ford, Marcellus, Niobrara, and Woodford shale plays. Their data provide information on fracture heights in shale. Top fracture heights varied between shale plays and within individual shale plays.



The **top fracture height** is the vertical distance upward from the well, between the fracture tip and the well.

Shale Play	Approximate Median Top Fracture Height [feet (meters)]
Eagle Ford	130 (40)
Woodford	160 (50)
Barnett	200 (60)
Marcellus	400 (120)
Niobrara	160 (50)



Source: Davies et al. (2012)

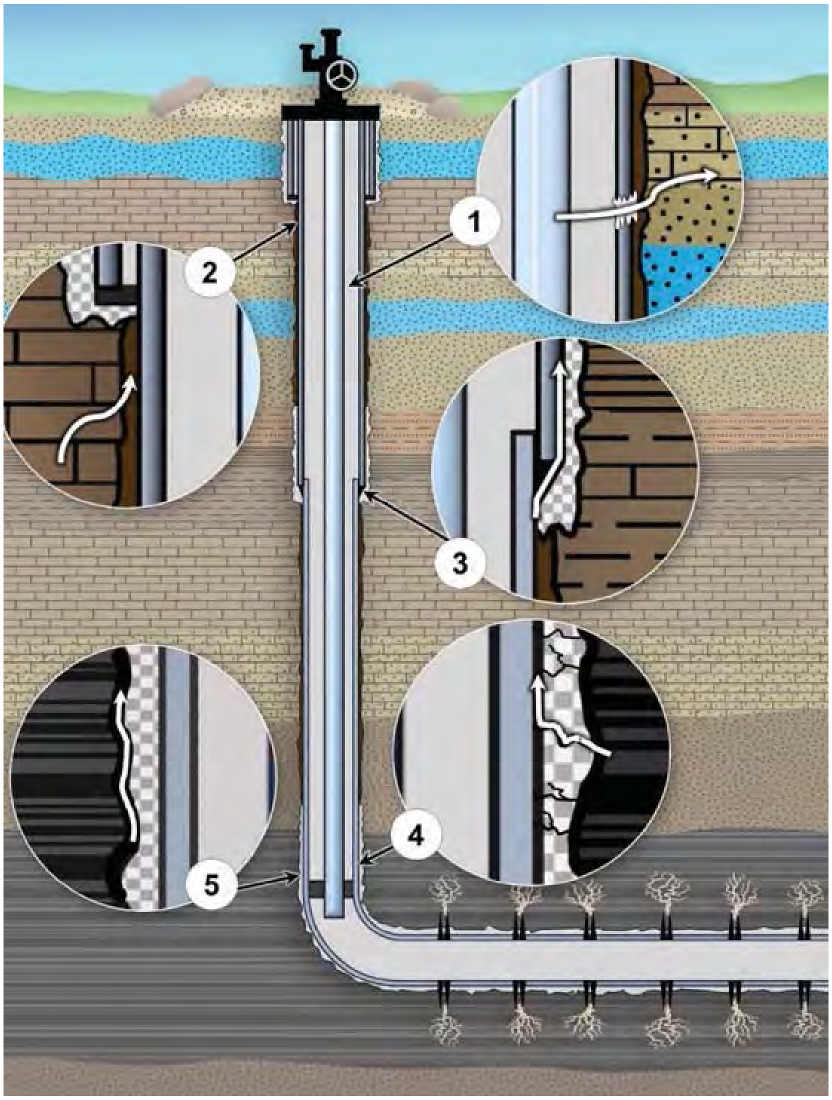


Figure ES-6. Potential pathways for fluid movement in a cemented well. These pathways (represented by the white arrows) include: (1) a casing and tubing leak into the surrounding rock, (2) an uncemented annulus (i.e., the space behind the casing), (3) microannuli between the casing and cement, (4) gaps in cement due to poor cement quality, and (5) microannuli between the cement and the surrounding rock. This figure is intended to provide a conceptual illustration of pathways that can be present in a well and is not to scale.

fracturing of an inadequately cemented gas well in Bainbridge Township, Ohio, contributed to the movement of methane into local drinking water resources.[1] In another case, an inner string of casing burst during hydraulic fracturing of an oil well near Killdeer, North Dakota, resulting in a release of hydraulic fracturing fluids and formation fluids that impacted a groundwater resource.

The potential for hydraulic fracturing fluids or other fluids to reach underground drinking water resources is also related to the fracture network created during hydraulic fracturing. Because fluids

[1] Although ingestion of methane is not considered to be toxic, methane can pose a physical hazard. Methane can accumulate to explosive levels when allowed to exsolve (degas) from groundwater in closed environments.

travel through the newly-created fractures, the location of these fractures relative to underground drinking water resources is an important factor affecting the frequency and severity of potential impacts on drinking water resources. Data on the relative location of induced fractures to underground drinking water resources are generally not available, because fracture networks are infrequently mapped and because there can be uncertainty in the depth of the bottom of the underground drinking water resource at a specific location.

Without these data, we were often unable to determine with certainty whether fractures created during hydraulic fracturing have reached underground drinking water resources. Instead, we considered the vertical separation distance between hydraulically fractured rock formations and the bottom of underground drinking water resources. Based on computer modeling studies, Birdsell et al. (2015) concluded that it is less likely that hydraulic fracturing fluids would reach an overlying drinking water resource if (1) the vertical separation distance between the targeted rock formation and the drinking water resource is large and (2) there are no open pathways (e.g., natural faults or fractures, or leaky wells). As the vertical separation distance between the targeted rock formation and the underground drinking water resource decreases, the likelihood of upward migration of hydraulic fracturing fluids to the drinking water resource increases (Birdsell et al., 2015).

Figure ES-7 illustrates how the vertical separation distance between the targeted rock formation and underground drinking water resources can vary across the United States. The two example environments depicted in panels a and b represent the range of separation distances shown in panel c. In Figure ES-7a, there are thousands of feet between the bottom of the underground drinking water resource and the hydraulically fractured rock formation. These conditions are generally reflective of deep shale formations (e.g., Haynesville Shale), where oil and gas production wells are first drilled vertically and then horizontally along the targeted rock formation. Microseismic data and modeling studies suggest that, under these conditions, fractures created during hydraulic fracturing are unlikely to grow through thousands of feet of rock into underground drinking water resources.

When drinking water resources are co-located with oil and gas resources and there is no vertical separation between the hydraulically fractured rock formation and the bottom of the underground drinking water resource (Figure ES-7b), the injection of hydraulic fracturing fluids impacts the quality of the drinking water resource. According to the information examined in this report, the overall occurrence of hydraulic fracturing within a drinking water resource appears to be low, with the activity generally concentrated in some areas in the western United States (e.g., the Wind River Basin near Pavillion, Wyoming, and the Powder River Basin of Montana and Wyoming).[1] Hydraulic fracturing within drinking water resources introduces hydraulic fracturing fluid into formations that may currently serve, or in the future could serve, as a drinking water source for public or private use. This is of concern in the short-term if people are currently using these formations as a drinking water supply. It is also of concern in the long-term, because drought or other conditions may necessitate the future use of these formations for drinking water.

Regardless of the vertical separation between the targeted rock formation and the underground drinking water resource, the presence of other wells near hydraulic fracturing operations can increase the potential for hydraulic fracturing fluids or other subsurface fluids to move to drinking water resources. There have been cases in which hydraulic fracturing at one well has affected a nearby oil and gas well or its fracture network, resulting in unexpected pressure increases at the nearby well, damage to the nearby well, or spills at the surface of the nearby well. These well communication events, or “frac hits,”

[1] Section 6.3.2 in Chapter 6.

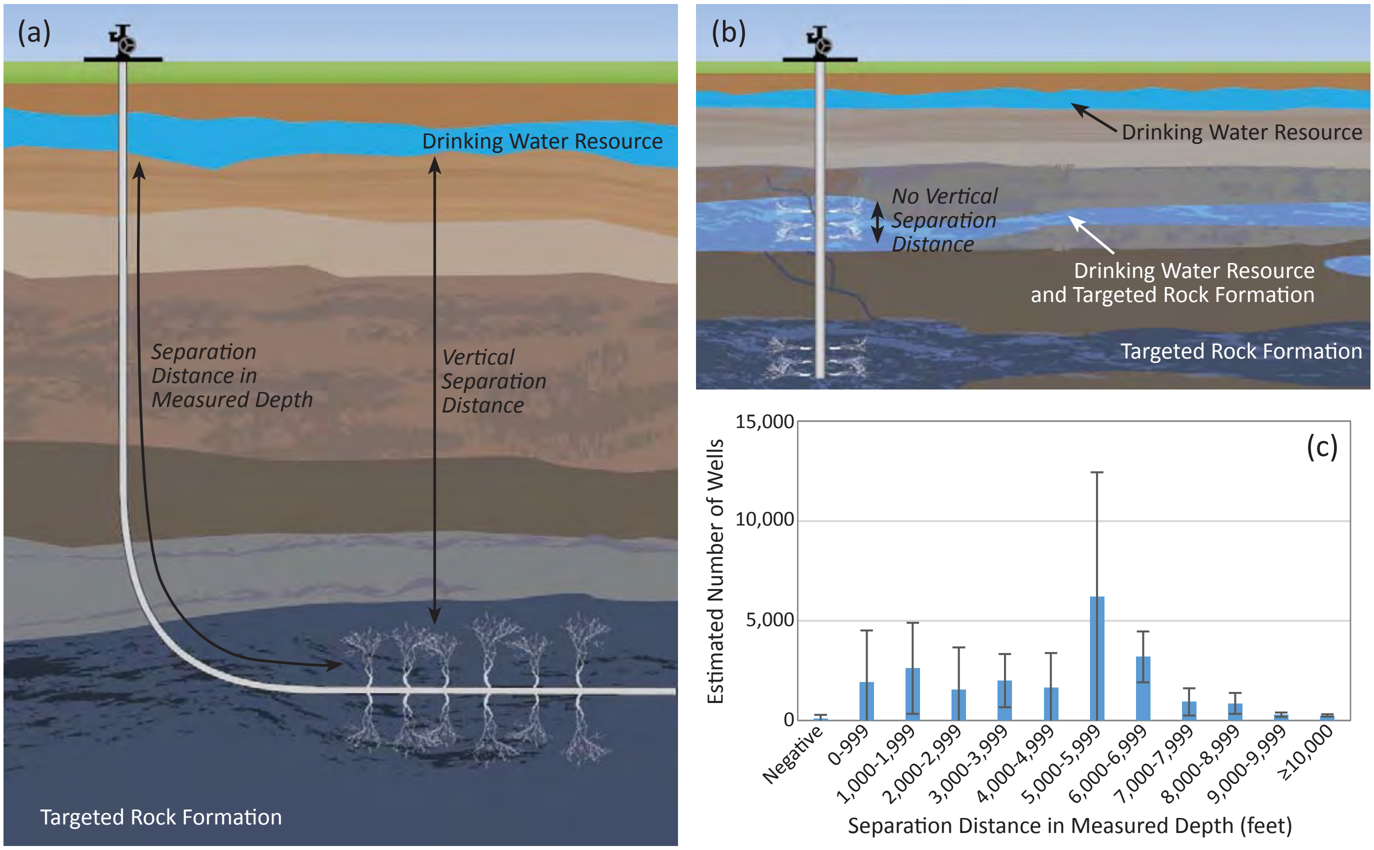


Figure ES-7. Examples of different subsurface environments in which hydraulic fracturing takes place. In panel a, there are thousands of feet between the base of the underground drinking water resource and the part of the well that is hydraulically fractured. Panel b illustrates the co-location of ground water and oil and gas resources. In these types of situations, there is no separation between the shallowest point of hydraulic fracturing within the well and the bottom of the underground drinking water resource. Panel c shows the estimated distribution of separation distances for approximately 23,000 oil and gas production wells hydraulically fractured by nine service companies between 2009 and 2019 (U.S. EPA, 2015d). The separation distance is the distance along the well between the point of shallowest hydraulic fracturing in the well and the base of the protected groundwater resource (illustrated in panel a). The error bars in panel c display 95% confidence intervals.

have been reported in New Mexico, Oklahoma, and other locations. Based on the available information, frac hits most commonly occur when multiple wells are drilled from the same surface location and when wells are spaced less than 1,100 feet (335 meters) apart. Frac hits have also been observed at wells up to 8,422 feet (2,567 meters) away from a well undergoing hydraulic fracturing.

Abandoned wells near a well undergoing hydraulic fracturing can provide a pathway for vertical fluid movement to drinking water resources if those wells were not properly plugged or if the plugs and cement have degraded over time. For example, an abandoned well in Pennsylvania produced a 30-foot (9-meter) geyser of brine and gas for more than a week after hydraulic fracturing of a nearby gas well. The potential for fluid movement along abandoned wells may be a significant issue in areas with historic oil and gas exploration and production. Various studies estimate the number of abandoned wells in the United States to be significant. For instance, the Interstate Oil and Gas Compact Commission estimates that over 1 million wells were drilled in the United States prior to the enactment of state oil and gas regulations (IOGCC, 2008). The location and condition of many of these wells are unknown, and some states have programs to find and plug abandoned wells.

Well Injection Conclusions

Impacts on drinking water resources associated with the well injection stage of the hydraulic fracturing water cycle have occurred in some instances. In particular, mechanical integrity failures have allowed gases or liquids to move to underground drinking water resources. Additionally, hydraulic fracturing has occurred within underground drinking water resources in parts of the United States. This practice introduces hydraulic fracturing fluids into underground drinking water resources. Consequently, the mechanical integrity of the well and the vertical separation distance between the targeted rock formation and underground drinking water resources are important factors that affect the frequency and severity of impacts on drinking water resources. The presence of multiple layers of cemented casing and thousands of feet of rock between hydraulically fractured rock formations and underground drinking water resources can reduce the frequency of impacts on drinking water resources during the well injection stage of the hydraulic fracturing water cycle.

Produced Water Handling

The on-site collection and handling of water that returns to the surface after hydraulic fracturing and the transportation of that water for disposal or reuse.

Relationship to Drinking Water Resources

Spills of produced water can reach groundwater and surface water resources.

After hydraulic fracturing, the injection pressure applied to the oil or gas production well is released, and the direction of fluid flow reverses, causing fluid to flow out of the well. The fluid that initially returns to the surface after hydraulic fracturing is mostly hydraulic fracturing fluid and is sometimes called "flowback" (Text Box ES-9). As time goes on, the fluid that returns to the surface contains water and economic quantities of oil and/or gas that are separated and collected. Water that returns to the surface during oil and gas production is similar in composition to the fluid naturally found in the targeted rock formation and is typically called "produced water." The term "produced water" is also used to refer to any water, including flowback, that returns to the surface through the production well as a by-product of oil and gas production. This latter definition of "produced water" is used in this report.

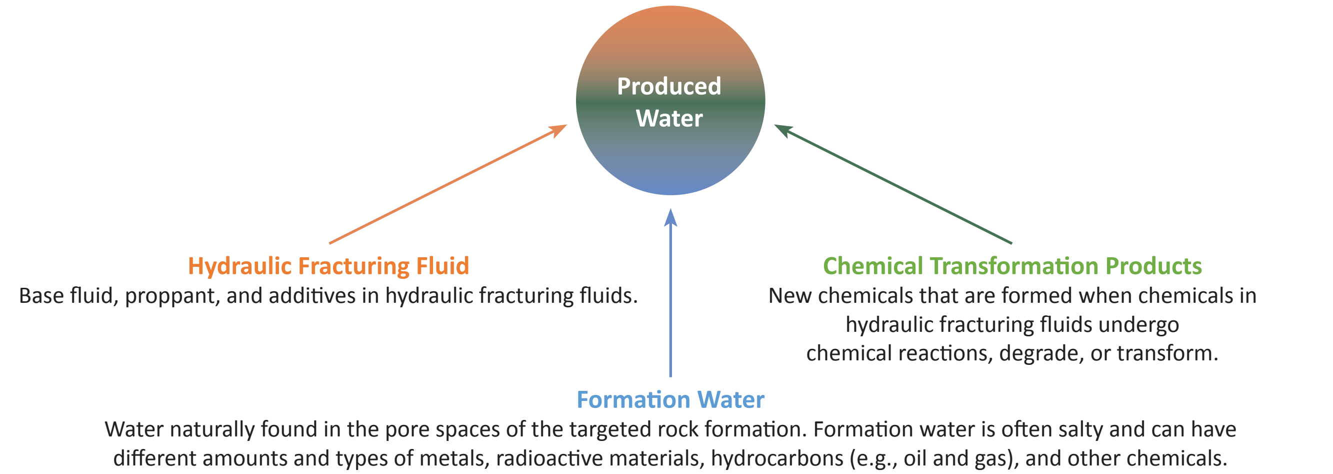
Produced water can contain many constituents, depending on the composition of the injected hydraulic fracturing fluid and the type of rock hydraulically fractured. Knowledge of the chemical composition of produced water comes from the collection and analysis of produced water samples, which often requires advanced laboratory equipment and techniques that can detect and quantify chemicals in produced water. In general, produced water has been found to contain:

- Salts, including those composed from chloride, bromide, sulfate, sodium, magnesium, and calcium;
- Metals, including barium, manganese, iron, and strontium;
- Naturally-occurring organic compounds, including benzene, toluene, ethylbenzene, xylenes (BTEX), and oil and grease;
- Radioactive materials, including radium; and
- Hydraulic fracturing chemicals and their chemical transformation products.

The amount of these constituents in produced water varies across the United States, both within

Text Box ES-9: Produced Water from Hydraulically Fractured Oil and Gas Production Wells

Water of varying quality is a byproduct of oil and gas production. The composition and volume of produced water varies by well, rock formation, and time after hydraulic fracturing. Produced water can contain hydraulic fracturing fluid, formation water, and chemical transformation products.

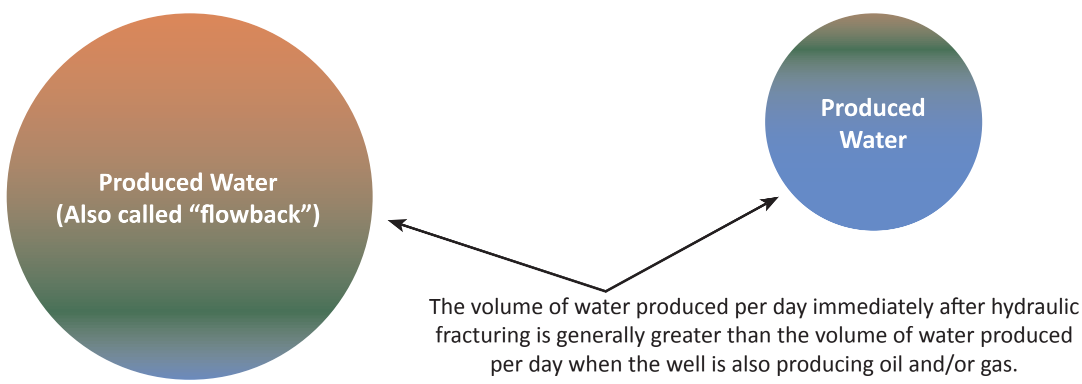


Water Produced Immediately After Hydraulic Fracturing

Generally, the fluid that initially returns to the surface is mostly a mixture of the injected hydraulic fracturing fluid and its reaction and degradation products.

Water Produced During Oil or Gas Production

The fluid that returns to the surface when oil and/or gas is produced generally resembles the formation water.



and among different rock formations. Produced water from shale and tight gas formations is typically very salty compared to produced water from coalbed methane formations. For example, the salinity of produced water from the Marcellus Shale has been reported to range from less than 1,500 milligrams per liter (mg/L) of total dissolved solids to over 300,000 mg/L, while produced water from coalbed methane formations has been reported to range from 170 mg/L of total dissolved solids to nearly 43,000 mg/L.[1] Shale and sandstone formations also commonly contain radioactive materials, including uranium, thorium, and radium. As a result, radioactive materials have been detected in produced water from these formations.

Produced water volumes can vary by well, rock formation, and time after hydraulic fracturing. Vol-

[1] For comparison, the average salinity of seawater is approximately 35,000 mg/L of total dissolved solids.

umes are often described in terms of the volume of hydraulic fracturing fluid used to fracture the well. For example, Figure ES-4 shows that wells in the Marcellus Shale typically produce 10-30% of the volume injected in the first 10 years after hydraulic fracturing. In comparison, some wells in the Barnett Shale have produced 100% of the volume injected in the first three years.

Because of the large volumes used for hydraulic fracturing [about 4 million gallons (15 million liters) per well in the Marcellus Shale and the Barnett Shale], hundreds of thousands to millions of gallons of produced water need to be collected and handled at the well site. The volume of water produced per day generally decreases with time, so the volumes handled on site immediately after hydraulic fracturing can be much larger than the volumes handled when the well is producing oil and/or gas (Text Box ES-9).

Produced water flows from the well to on-site tanks or pits through a series of pipes or flowlines (Text Box ES-10) before being transported offsite via trucks or pipelines for disposal or reuse. While produced water collection, storage, and transportation systems are designed to contain produced water, spills can occur. Changes in drinking water quality can occur if produced water spills reach groundwater or surface water resources.

Produced water spills have been reported across the United States. Median spill volumes among the datasets reviewed for this report ranged from approximately 340 gallons (1,300 liters) to 1,000 gallons (3,800 liters) per spill.[1] There were, however, a small number of large volume spills. In North Dakota, for example, there were 12 spills greater than 21,000 gallons (79,500 liters), five spills greater than 42,000 gallons (160,000 liters), and one spill of 2.9 million gallons (11 million liters) in 2015. Common causes of produced water spills included human error and equipment leaks or failures. Common sources of produced water spills included hoses or lines and storage equipment.

Spills of produced water have reached groundwater and surface water resources. In U.S. EPA (2015c), 30 of the 225 (13%) produced water spills characterized were reported to have reached surface water (e.g., creeks, ponds, or wetlands), and one was reported to have reached groundwater. Of the spills that were reported to have reached surface water, reported spill volumes ranged from less than 170 gallons (640 liters) to almost 74,000 gallons (280,000 liters). A separate assessment of produced water spills reported to the California Office of Emergency Services between January 2009 and December 2014 reported that 18% of the spills impacted waterways (CCST, 2015).

Documented cases of water resource impacts from produced water spills provide insights into the types of impacts that can occur. In most of the cases reviewed for this report, documented impacts included elevated levels of salinity in groundwater and/or surface water resources.[2] For example, the largest produced water spill reported in this report occurred in North Dakota in 2015, when approximately 2.9 million gallons (11 million liters) of produced water spilled from a broken pipeline. The spilled fluid flowed into Blacktail Creek and increased the concentration of chloride and the electrical conductivity of the creek; these observations are consistent with an increase in water salinity. Elevated levels of electrical conductivity and chloride were also found downstream in the Little Muddy River and the Missouri River. In another example, pits holding flowback fluids overflowed in Kentucky in 2007. The spilled fluid reached the Acorn Fork Creek, decreasing the pH of the creek and increasing the electrical conductivity.

Site-specific studies of historical produced water releases highlight the role of local geology in the movement of produced water through the environ-

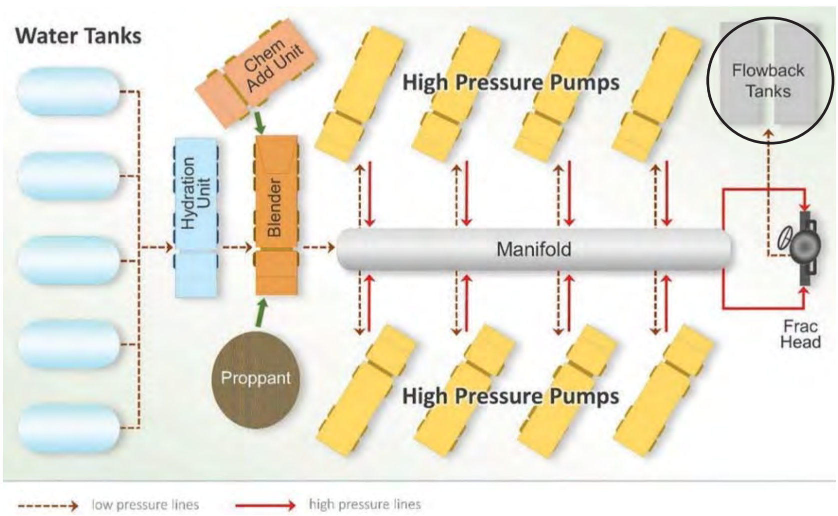
[1] See Section 7.4 in Chapter 7.

[2] Groundwater impacts from produced water management practices are described in Chapter 8 and summarized in the “Wastewater Disposal and Reuse” section below.

Text Box ES-10: On-Site Storage of Produced Water

Water that returns to the surface after hydraulic fracturing is collected and stored on site in pits or tanks.

Above: Flowback pit. (Source: U.S. DOE/NETL)
Right: Flowback tanks. (Source: U.S. EPA)



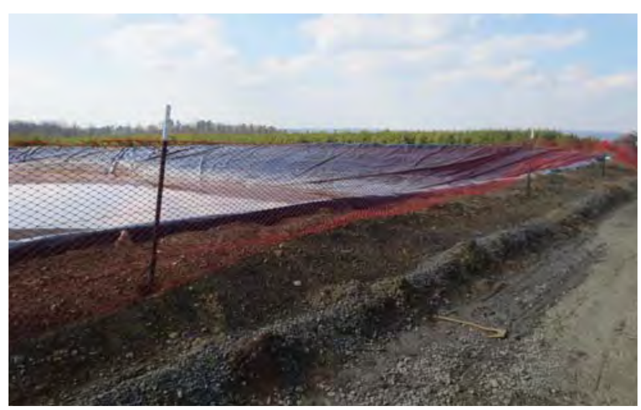
Produced Water Storage Immediately after Hydraulic Fracturing

After hydraulic fracturing, water is returned to the surface. Water initially produced from the well after hydraulic fracturing is sometimes called “flowback.” This water can be stored onsite in tanks or pits before being taken offsite for injection in Class II wells, reuse in other hydraulic fracturing operations, or aboveground disposal.

Source: Adapted from Olson (2011) and BJ Services Company (2009)

Produced Water Storage During Oil or Gas Production

Water is generally produced throughout the life of an oil and gas production well. During oil and gas production, the equipment on the well pad often includes the wellhead and storage tanks or pits for gas, oil, and produced water.



Above: Produced water storage pit. (Source: U.S. EPA)
Left: Produced water storage tanks. (Source: U.S. EPA)

ment. Whittemore (2007) described a site in Kansas where low permeability soils and rock caused produced water to primarily flow over the land surface to nearby surface water resources, reducing the amount of produced water that infiltrated soil. In contrast, Otton et al. (2007) explored the release of produced water and oil from two pits in Oklahoma. In this case, produced water from the pits flowed through thin soil and into the underlying, permeable rock. Produced water was also identified in deeper, less permeable rock. The authors suggest that produced water moved into the deeper, less permeable rock through natural fractures. Together, these studies highlight the role of preferential flow paths (i.e., paths of least resistance) in the movement of produced water through the environment.

Spill response activities likely reduce the severity of impacts on groundwater and surface water resources from produced water spills. For example, in the North Dakota example noted above, absorbent booms were placed in the affected creek and contaminated soil and oil-coated ice were removed from the site. In another example, a pipeline leak in Pennsylvania spilled approximately 11,000 gallons (42,000 liters) of produced water, which flowed into a nearby stream. In response, the pipeline was shut off, a dam was constructed to contain the spilled produced water, water was removed from the stream, and the stream was flushed with fresh water. In both examples, it was not possible to quantify how spill response activities reduced the severity of impacts on groundwater or surface water resources. However, actions taken after the spills were designed to stop produced water from entering the environment (e.g., shutting off a pipeline), remove produced water from the environment (e.g., using absorbent booms), and reduce the concentration of produced water constituents introduced into water resources (e.g., flushing a stream with fresh water).

The severity of impacts on water quality from spills of produced water depends on the identity and amount of produced water constituents that reach groundwater or surface water resources, the toxicity of those constituents, and the characteristics of the receiving water resource.[1] In particular, spills of produced water can have high levels of total dissolved solids, which affects how the spilled fluid moves through the environment. When a spilled fluid has greater levels of total dissolved solids than groundwater, the higher-density fluid can move downward through groundwater resources. Depending on the flow rate and other properties of the groundwater resource, impacts from produced water spills can last for years.

Produced Water Handling Conclusions

Spills of produced water during the produced water handling stage of the hydraulic fracturing water cycle have reached groundwater and surface water resources in some cases. Several cases of water resource impacts from produced water spills suggest that impacts are characterized by increases in the salinity of the affected groundwater or surface water resource. In the absence of direct pathways to groundwater resources (e.g., fractured rock), large volume spills are more likely to travel further from the site of the spill, potentially to groundwater or surface water resources. Additionally, saline produced water can migrate downward through soil and into groundwater resources, leading to longer-term groundwater contamination. Spill prevention and response activities can prevent spilled fluids from reaching groundwater or surface water resources and minimize impacts from spilled fluids.

[1] Human health hazards associated with chemicals detected in produced water are discussed in Chapter 9 and summarized in the "Chemicals in the Hydraulic Fracturing Water Cycle" section below.

Wastewater Disposal and Reuse

The disposal and reuse of hydraulic fracturing wastewater.

Relationship to Drinking Water Resources

Disposal practices can release inadequately treated or untreated hydraulic fracturing wastewater to groundwater and surface water resources.

In general, produced water from hydraulically fractured oil and gas production wells is managed through injection in Class II wells, reuse in other hydraulic fracturing operations, or various aboveground disposal practices (Text Box ES-11). In this report, produced water from hydraulically fractured oil and gas wells that is being managed through one of the above management strategies is referred to as "hydraulic fracturing wastewater." Wastewater management choices are affected by cost and other factors, including: the local availability of disposal methods; the quality of produced water; the volume, duration, and flow rate of produced water; federal, state, and local regulations; and well operator preferences.

Available information suggests that hydraulic fracturing wastewater is mostly managed through injection in Class II wells. Veil (2015) estimated that 93% of produced water from the oil and gas industry was injected in Class II wells in 2012. Although this estimate included produced water from oil and gas wells in general, it is likely indicative of nationwide management practices for hydraulic fracturing wastewater. Disposal of hydraulic fracturing wastewater in Class II wells is often cost-effective, especially when a Class II disposal well is located within a reasonable distance from a hydraulically fractured oil or gas production well. In particular, large numbers of active Class II disposal wells are found in Texas (7,876), Kansas (5,516), Oklahoma (3,837), Louisiana (2,448), and Illinois (1,054) (U.S. EPA, 2016). Disposal of hydraulic fracturing wastewater in Class II wells has been associated with earthquakes in several states, which may reduce the availability of injection in Class II wells as a wastewater disposal option in these states.

Nationwide, aboveground disposal and reuse of hydraulic fracturing wastewater are currently practiced to a much lesser extent compared to injection in Class II wells, and these management strategies appear to be concentrated in certain parts of the United States. For example, approximately 90% of hydraulic fracturing wastewater from Marcellus Shale gas wells in Pennsylvania was reused in other hydraulic fracturing operations in 2013 (Figure ES-4a). Reuse in hydraulic fracturing operations is practiced in some other areas of the United States as well, but at lower rates (approximately 5-20%). Evaporation ponds and percolation pits have historically been used in the western United States to manage produced water from the oil and gas industry and have likely been used to manage hydraulic fracturing wastewater. Percolation pits, in particular, were commonly reported to have been used to manage produced water from stimulated wells in Kern County, California, between 2011 and 2014.[1] Beneficial uses (e.g., livestock watering and irrigation) are also practiced in the western United States if the water quality is considered acceptable, although available data on the use of these practices are incomplete.

Aboveground disposal practices generally release treated or, under certain conditions, untreated wastewater directly to surface water or the land surface (e.g., wastewater treatment facilities, evaporation pits, or irrigation). If released to the land surface,

[1] Hydraulic fracturing was the predominant stimulation practice. Other stimulation practices included acid fracturing and matrix acidizing. California updated its regulations in 2015 to prohibit the use of percolation pits for the disposal of fluids produced from stimulated wells.

Text Box ES-11: Hydraulic Fracturing Wastewater Management

Produced water from hydraulically fractured oil and gas production wells is often, but not always, considered a waste product to be managed. Hydraulic fracturing wastewater (i.e., produced water from hydraulically fractured wells) is generally managed through injection in Class II wells, reuse in other hydraulic fracturing operations, and various aboveground disposal practices.

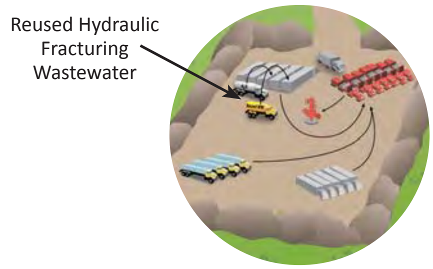
Injection in Class II Wells

Most oil and gas wastewater—including hydraulic fracturing wastewater—is injected in Class II wells, which are regulated under the Underground Injection Control Program of the Safe Drinking Water Act.

Class II wells are used to inject wastewater associated with oil and gas production underground. Fluids can be injected for disposal or to enhance oil or gas production from nearby oil and gas production wells.

Reuse in Other Hydraulic Fracturing Operations

Hydraulic fracturing wastewater can be used, in combination with fresh water, to make up hydraulic fracturing fluids at nearby hydraulic fracturing operations.

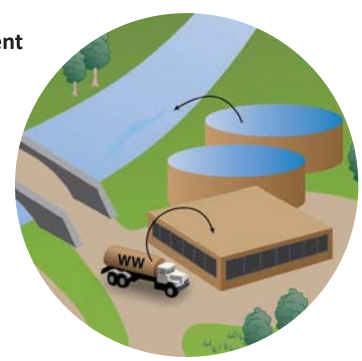


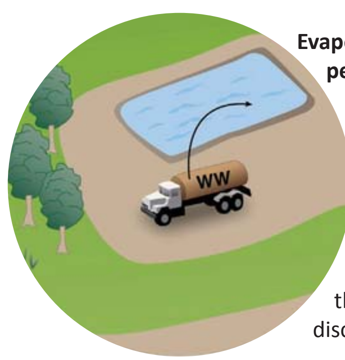
Reuse in other hydraulic fracturing operations depends on the quality and quantity of the available wastewater, the cost associated with treatment and transportation of the wastewater, and local water demand for hydraulic fracturing.

Aboveground Disposal Practices

Aboveground disposal of treated and untreated hydraulic fracturing wastewater can take many forms, including release to surface water resources and land application.

Some **wastewater treatment facilities** treat hydraulic fracturing wastewater and release the treated wastewater to surface water. Solid or liquid by-products of the treatment process can be sent to landfills or injected underground.





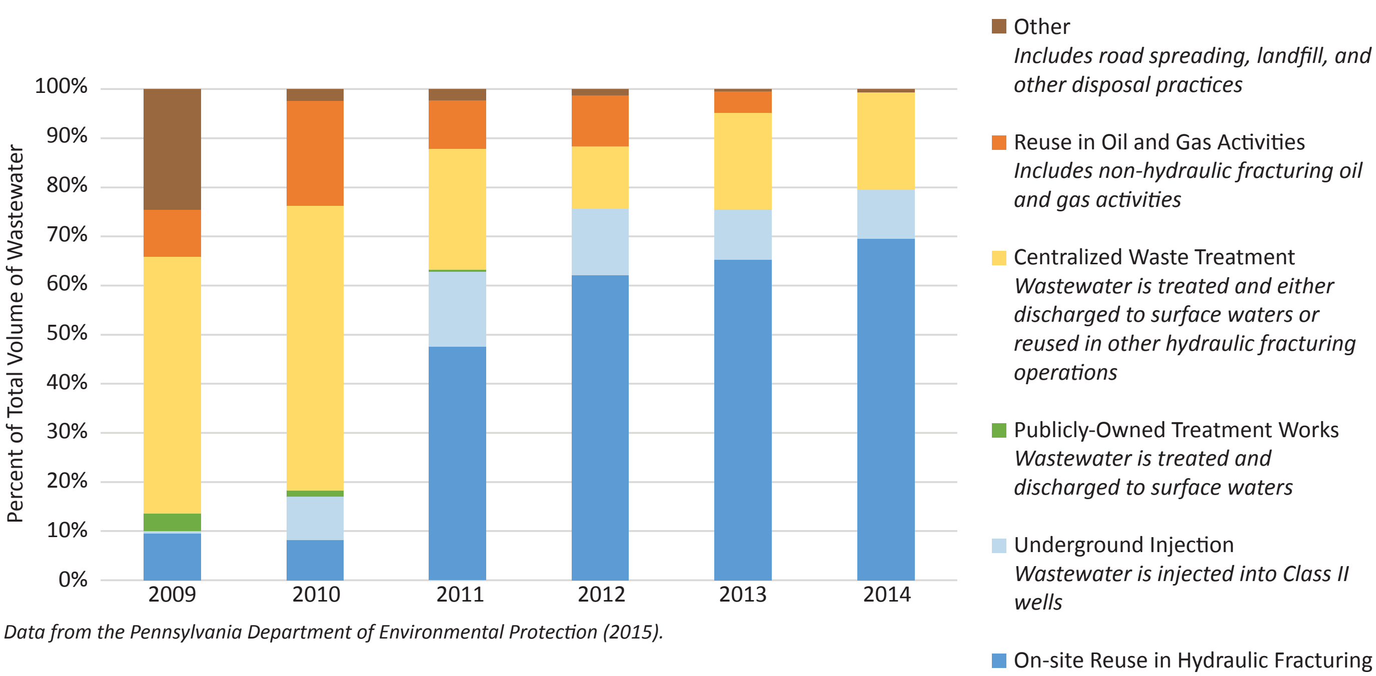
Evaporation ponds and **percolation pits** can be used for hydraulic fracturing wastewater disposal. Evaporation ponds allow liquid waste to naturally evaporate. Percolation pits allow wastewater to move into the ground, although this practice has been discontinued in most states.

Federal and state regulations affect aboveground disposal management options. For example, existing federal regulations generally prevent the direct release of wastewater pollutants to waters of the United States from onshore oil and gas extraction facilities east of the 98th meridian. However, in the arid western portion of the continental United States (west of the 98th meridian), direct discharges of wastewater from onshore oil and gas extraction facilities to waters of the United States may be permitted if the produced water has a use in agriculture or wildlife propagation and meets established water quality criteria when discharged.

treated or untreated wastewater can move through soil to groundwater resources. Because the ultimate fate of the wastewater can be groundwater or surface water resources, the aboveground disposal of hydraulic fracturing wastewater, in particular, can impact drinking water resources.

Impacts on drinking water resources from the aboveground disposal of hydraulic fracturing wastewater have been documented. For example, early wastewater management practices in the Marcellus Shale region in Pennsylvania included the use of wastewater treatment facilities that released (i.e., discharged) treated wastewater to surface waters (Figure ES-8). The wastewater treatment facilities were unable to adequately remove the high levels of total dissolved solids found in produced water from Marcellus Shale gas wells, and the discharges contributed to elevated levels of total dissolved solids (particularly bromide) in the Monongahela River Basin. In the Allegheny River Basin, elevated bromide levels were linked to increases in the concentration of hazardous disinfection byproducts in at least one downstream drinking water facility and a shift to more toxic brominated disinfection byproducts.[1] In response, the Pennsylvania Department of Environmental Protection revised existing regulations to prevent these discharges and also requested that oil and gas operators voluntarily stop bringing certain kinds of hydraulic fracturing wastewater to facilities that discharge inadequately treated wastewater to surface waters.[2]

The scientific literature and recent data from the Pennsylvania Department of Environmental Protection suggest that other produced water constituents



Data from the Pennsylvania Department of Environmental Protection (2015).

Figure ES-8. Changes in wastewater management practices over time in the Marcellus Shale area of Pennsylvania.

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[1] Disinfection byproducts form through chemical reactions between organic material and disinfectants, which are used in drinking water treatment. Human health hazards associated with disinfection byproducts are described in Section 9.5.6 in Chapter 9.

[2] See Text Box 8-1 in Chapter 8.

(e.g., barium, strontium, and radium) may have been introduced to surface waters through the release of inadequately treated hydraulic fracturing wastewater. In particular, radium has been detected in stream sediments at or near wastewater treatment facilities that discharged inadequately treated hydraulic fracturing wastewater. Such sediments can migrate if they are disturbed during dredging or flood events. Additionally, residuals from the treatment of hydraulic fracturing wastewater (i.e., the solids or liquids that remain after treatment) are concentrated in the constituents removed during treatment, and these residuals can impact groundwater or surface water resources if they are not managed properly.

Impacts on groundwater and surface water resources from current and historic uses of lined and unlined pits, including percolation pits, in the oil and gas industry have been documented. For example, Kell (2011) reported 63 incidents of non-public water supply contamination from unlined or inadequately constructed pits in Ohio between 1983 and 2007, and 57 incidents of groundwater contamination from unlined produced water disposal pits in Texas prior to 1984. Other cases of impacts have been identified in several states, including New Mexico, Oklahoma, Pennsylvania, and Wyoming.[1] Impacts among these cases included the detection of volatile organic compounds in groundwater resources, wastewater reaching surface water resources from pit overflows, and wastewater reaching groundwater resources through liner failures. Based on documented impacts on groundwater resources from unlined pits, many states have implemented regulations that prohibit percolation pits or unlined storage pits for either hydraulic fracturing wastewater or oil and gas wastewater in general.

The severity of impacts on drinking water resources from the aboveground disposal of hydraulic fracturing wastewater depends on the volume and quality of the discharged wastewater and the characteristics of the receiving water resource. In general, large surface water resources with high flow rates can reduce the severity of impacts through dilution, although impacts may not be eliminated. In contrast, groundwater is generally slow moving, which can lead to an accumulation of hydraulic fracturing wastewater contaminants in groundwater from continuous or repeated discharges to the land surface; the resulting contamination can be long-lasting. The severity of impacts on groundwater resources will also be influenced by soil and sediment properties and other factors that control the movement or degradation of wastewater constituents.

Wastewater Disposal and Reuse Conclusions

The aboveground disposal of hydraulic fracturing wastewater has impacted the quality of groundwater and surface water resources in some instances. In particular, discharges of inadequately treated hydraulic fracturing wastewater to surface water resources have contributed to elevated levels of hazardous disinfection byproducts in at least one downstream drinking water system. Additionally, the use of lined and unlined pits for the storage or disposal of oil and gas wastewater has impacted surface and groundwater resources. Unlined pits, in particular, provide a direct pathway for contaminants to reach groundwater. Wastewater management is dynamic, and recent changes in state regulations and practices have been made to limit impacts on groundwater and surface water resources from the aboveground disposal of hydraulic fracturing wastewater.

[1] See Section 8.4.5 in Chapter 8.

Chemicals in the Hydraulic Fracturing Water Cycle

Chemicals are present in the hydraulic fracturing water cycle. During the chemical mixing stage of the hydraulic fracturing water cycle, chemicals are intentionally added to water to alter its properties for hydraulic fracturing (Text Box ES-6). Produced water, which is collected, handled, and managed in the last two stages of the hydraulic fracturing water cycle, contains chemicals added to hydraulic fracturing fluids, naturally occurring chemicals found in hydraulically fractured rock formations, and any chemical transformation products (Text Box ES-9). By evaluating available data sources, we compiled a list of 1,606 chemicals that are associated with the hydraulic fracturing water cycle, including 1,084 chemicals reported to have been used in hydraulic fracturing fluids and 599 chemicals detected in produced water. This list represents a national analysis; an individual well would likely have a fraction of the chemicals on this list and may have other chemicals that were not included on this list.

In many stages of the hydraulic fracturing water cycle, the severity of impacts on drinking water resources depends, in part, on the identity and amount of chemicals that enter the environment. The properties of a chemical influence how it moves and transforms in the environment and how it interacts with the human body. Therefore, some chemicals in the hydraulic fracturing water cycle are of more concern than others because they are more likely to move with water (e.g., spilled hydraulic fracturing fluid) to drinking water resources, persist in the environment (e.g., chemicals that do not degrade), and/or affect human health.

Evaluating potential hazards from chemicals in the hydraulic fracturing water cycle is most useful at local and/or regional scales because chemical use for hydraulic fracturing can vary from well to well and because the characteristics of produced water are influenced by the geochemistry of hydraulically fractured rock formations. Additionally, site-specific characteristics (e.g., the local landscape, and soil and subsurface permeability) can affect whether and how chemicals enter drinking water resources, which influences how long people may be exposed to specific chemicals and at what concentrations. As a first step for informing site-specific risk assessments, the EPA compiled toxicity values for chemicals in the hydraulic fracturing water cycle from federal, state, and international sources that met the EPA's criteria for inclusion in this report.[1,2]

The EPA was able to identify chronic oral toxicity values from the selected data sources for 98 of the 1,084 chemicals that were reported to have been used in hydraulic fracturing fluids between 2005 and 2013. Potential human health hazards associated with chronic oral exposure to these chemicals include cancer, immune system effects, changes in body weight, changes in blood chemistry, cardiotoxicity, neurotoxicity, liver and kidney toxicity, and reproductive and developmental toxicity. Of the chemicals most frequently reported to FracFocus 1.0, nine had toxicity values from the selected data sources (Table ES-3). Critical effects for these chemicals include kidney/renal toxicity, hepatotoxicity, developmental toxicity (extra cervical ribs), reproductive toxicity, and decreased terminal body weight.

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[1] Specifically, the EPA compiled noncancer oral reference values and cancer oral slope factors (Chapter 9). A reference value describes the dose of a chemical that is likely to be without an appreciable risk of adverse health effects. In the context of this report, the term "reference value" generally refers to reference values for noncancer effects occurring via the oral route of exposure and for chronic durations. An oral slope factor is an upper-bound estimate on the increased cancer risk from a lifetime oral exposure to an agent.

[2] The EPA's criteria for inclusion in this report are described in Section 9.4.1 in Chapter 9. Sources of information that met these criteria are listed in Table 9-1 of Chapter 9.

Table ES-3. Available chronic oral reference values for hydraulic fracturing chemicals reported in 10% or more of disclosures in FracFocus 1.0.

Chemical Name (CASRN)[a]	Chronic Oral Reference Value (milligrams per kilogram per day)	Critical Effect	Percent of FracFocus 1.0 Disclosures[b]
Propargyl alcohol (107-19-7)	0.002[c]	Renal and hepatotoxicity	33
1,2,4-Trimethylbenzene (95-63-6)	0.01[c]	Decreased pain sensitivity	13
Naphthalene (91-20-3)	0.02[c]	Decreased terminal body weight	19
Sodium chlorite (7758-19-2)	0.03[c]	Neuro-developmental effects	11
2-Butoxyethanol (111-76-2)	0.1[c]	Hemosiderin deposition in the liver	23
Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl, chlorides (68424-85-1)	0.44[d]	Decreased body weight and weight gain	12
Formic acid (64-18-6)	0.9[e]	Reproductive toxicity	11
Ethylene glycol (107-21-1)	2[c]	Kidney toxicity	47
Methanol (67-56-1)	2[c]	Extra cervical ribs	73

[a]"Chemical" refers to chemical substances with a single CASRN; these may be pure chemicals (e.g., methanol) or chemical mixtures (e.g., hydrotreated light petroleum distillates).
[b]Analysis considered 35,957 disclosures that met selected quality assurance criteria. See Table 9-2 in Chapter 9.
[c]From the EPA Integrated Risk Information System database.
[d]From the EPA Human Health Benchmarks for Pesticides database.
[e]From the EPA Provisional Peer-Reviewed Toxicity Value database.

Chronic oral toxicity values from the selected data sources were identified for 120 of the 599 chemicals detected in produced water. Potential human health hazards associated with chronic oral exposure to these chemicals include liver toxicity, kidney toxicity, neurotoxicity, reproductive and developmental toxicity, and carcinogenesis. Chemical-specific toxicity values are included in Chapter 9.

Chemicals in the Hydraulic Fracturing Water Cycle Conclusions

Some of the chemicals in the hydraulic fracturing water cycle are known to be hazardous to human health. Of the 1,606 chemicals identified by the EPA, 173 had chronic oral toxicity values from federal, state, and international sources that met the EPA's criteria for inclusion in this report. These data alone, however, are insufficient to determine which chemicals have the greatest potential to impact drinking water resources and human health. To understand whether specific chemicals can affect human health through their presence in drinking water, data on chemical concentrations in drinking water would be needed. In the absence of these data, relative hazard potential assessments could be conducted at local and/or regional scales using the multi-criteria decision analysis approach outlined in Chapter 9. This approach combines available chemical occurrence data with selected chemical, physical, and toxicological properties to place the severity of potential impacts (i.e., the toxicity of specific chemicals) into the context of factors that affect the likelihood of impacts (i.e., frequency of use, and chemical and physical properties relevant to environmental fate and transport).

Data Gaps and Uncertainties

The information reviewed for this report included cases of impacts on drinking water resources from activities in the hydraulic fracturing water cycle. Using these cases and other data, information, and analyses, we were able to identify factors that likely result in more frequent or more severe impacts on drinking water resources. However, there were instances in which we were unable to form conclusions about the potential for activities in the hydraulic fracturing water cycle to impact drinking water resources and/or the factors that influence the frequency or severity of impacts. Below, we provide perspective on the data gaps and uncertainties that prevented us from drawing additional conclusions about the potential for impacts on drinking water resources and/or the factors that affect the frequency and severity of impacts.

In general, comprehensive information on the location of activities in the hydraulic fracturing water cycle is lacking, either because it is not collected, not publicly available, or prohibitively difficult to aggregate. This includes information on the:

- Above- and belowground locations of water withdrawals for hydraulic fracturing;
- Surface locations of hydraulically fractured oil and gas production wells, where the chemical mixing, well injection, and produced water handling stages of the hydraulic fracturing water cycle take place;
- Belowground locations of hydraulic fracturing, including data on fracture growth; and
- Locations of hydraulic fracturing wastewater management practices, including the disposal of treatment residuals.

There can also be uncertainty in the location of drinking water resources. In particular, depths of groundwater resources that are, or in the future could be, used for drinking water are not always known. If comprehensive data about the locations of both drinking water resources and activities in the hydraulic fracturing water cycle were available, it would have been possible to more completely identify areas in the United States in which hydraulic fracturing-related activities either directly interact with drinking water resources or have the potential to interact with drinking water resources.

In places where we know activities in the hydraulic fracturing water cycle have occurred or are occurring, data that could be used to characterize the presence, migration, or transformation of hydraulic fracturing-related chemicals in the environment before, during, and after hydraulic fracturing were scarce. Specifically, local water quality data needed to compare pre- and post-hydraulic fracturing conditions are not usually collected or readily available. The limited amount of data collected before, during, and after activities in the hydraulic fracturing water cycle reduces the ability to determine whether these activities affected drinking water resources.

Site-specific cases of alleged impacts on underground drinking water resources during the well injection stage of the hydraulic fracturing water cycle are particularly challenging to understand (e.g., methane migration in Dimock, Pennsylvania; the Raton Basin of Colorado; and Parker County, Texas[1]). This is because the subsurface environment is complex and belowground fluid movement is not directly observable. In cases of alleged impacts, activities in the hydraulic fracturing water cycle may be one of several causes of impacts, including other oil and gas activities, other industries, and natural processes. Thorough scientific investigations are often necessary to narrow down the list of potential causes to a single source at site-specific cases of alleged impacts.

Additionally, information on chemicals in the hydraulic fracturing water cycle (e.g., chemical iden-

[1] See Text Boxes 6-2 (Dimock, Pennsylvania), 6-3 (Raton Basin), and 6-4 (Parker County, Texas) in Chapter 6.

tity; frequency of use or occurrence; and physical, chemical, and toxicological properties) is not complete. Well operators claimed at least one chemical as confidential at more than 70% of wells reported to FracFocus 1.0 (U.S. EPA, 2015a).[1] The identity and concentration of these chemicals, their transformation products, and chemicals in produced water would be needed to characterize how chemicals associated with hydraulic fracturing activities move through the environment and interact with the human body. Identifying chemicals in the hydraulic fracturing water cycle also informs decisions about which chemicals would be appropriate to test for when establishing pre-hydraulic fracturing baseline conditions and in the event of a suspected drinking water impact.

Of the 1,606 chemicals identified by the EPA in hydraulic fracturing fluid and/or produced water, 173 had toxicity values from sources that met the EPA's criteria for inclusion in this report. Toxicity values from these selected data sources were not available for 1,433 (89%) of the chemicals, although many of these chemicals have toxicity data available from other data sources.[2] Given the large number of chemicals identified in the hydraulic fracturing water cycle, this missing information represents a significant data gap that makes it difficult to fully understand the severity of potential impacts on drinking water resources.

Because of the significant data gaps and uncertainties in the available data, it was not possible to fully characterize the severity of impacts, nor was it possible to calculate or estimate the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle. We were, however, able to estimate impact frequencies in some, limited cases (i.e., spills of hydraulic fracturing fluids or produced water and mechanical integrity failures).[3] The data used to develop these estimates were often limited in geographic scope or otherwise incomplete. Consequently, national estimates of impact frequencies for any stage of the hydraulic fracturing water cycle have a high degree of uncertainty. Our inability to quantitatively determine a national impact frequency or to characterize the severity of impacts, however, did not prevent us from qualitatively describing factors that affect the frequency or severity of impacts at the local level.

Report Conclusions

This report describes how activities in the hydraulic fracturing water cycle can impact—and have impacted—drinking water resources and the factors that influence the frequency and severity of those impacts. It also describes data gaps and uncertainties that limited our ability to draw additional conclusions about impacts on drinking water resources from activities in the hydraulic fracturing water cycle. Both types of information—what we know and what we do not know—provide stakeholders with scientific information to support future efforts.

The uncertainties and data gaps identified throughout this report can be used to identify future efforts to further our understanding of the potential for activities in the hydraulic fracturing water cycle to impact drinking water resources and the factors that affect the frequency and severity of those impacts. Future efforts could include, for example, groundwater and surface water monitoring in areas with hydraulically fractured oil and gas production wells or tar-

[1] Chemical withholding rates in FracFocus have increased over time. Konschnik and Dayalu (2016) reported that 92% of wells reported in FracFocus 2.0 between approximately March 2011 and April 2015 used at least one chemical that was claimed as confidential.

[2] Chapter 9 describes the availability of data in other data sources. The quality of these data sources was not evaluated as part of this report.

[3] See Chapter 10.

geted research programs to better characterize the environmental fate and transport and human health hazards associated with chemicals in the hydraulic fracturing water cycle. Future efforts could identify additional vulnerabilities or other factors that affect the frequency and/or severity of impacts.

In the near term, decision-makers could focus their attention on the combinations of hydraulic fracturing water cycle activities and local- or regional-scale factors that are more likely than others to result in more frequent or more severe impacts. These include:

- Water withdrawals for hydraulic fracturing in times or areas of low water availability, particularly in areas with limited or declining groundwater resources;
- Spills during the management of hydraulic fracturing fluids and chemicals or produced water that result in large volumes or high concentrations of chemicals reaching groundwater resources;
- Injection of hydraulic fracturing fluids into wells with inadequate mechanical integrity, allowing gases or liquids to move to groundwater resources;
- Injection of hydraulic fracturing fluids directly into groundwater resources;
- Discharge of inadequately treated hydraulic fracturing wastewater to surface water resources; and
- Disposal or storage of hydraulic fracturing wastewater in unlined pits, resulting in contamination of groundwater resources.

The above combinations of activities and factors highlight, in particular, the vulnerability of groundwater resources to activities in the hydraulic fracturing water cycle. By focusing attention on the situations described above, impacts on drinking water resources from activities in the hydraulic fracturing water cycle could be prevented or reduced.

Overall, hydraulic fracturing for oil and gas is a practice that continues to evolve. Evaluating the potential for activities in the hydraulic fracturing water cycle to impact drinking water resources will need to keep pace with emerging technologies and new scientific studies. This report provides a foundation for these efforts, while helping to reduce current vulnerabilities to drinking water resources.

Source: U.S. EPA

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Front cover (top): Illustrations of activities in the hydraulic fracturing water cycle. From left to right: Water Acquisition, Chemical Mixing, Well Injection, Produced Water Handling, and Wastewater Disposal and Reuse.

Front cover (bottom): Aerial photographs of hydraulic fracturing activities. Left: Near Williston, North Dakota. Image ©J Henry Fair / Flights provided by LightHawk. Right: Springville Township, Pennsylvania. Image ©J Henry Fair / Flights provided by LightHawk.

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United States
Environmental Protection
Agency

Office of Research and Development (8101R)
U.S. Environmental Protection Agency
Washington, DC 20460

Official Business
Penalty for Private Use
$300

January 26, 2017

Montana Board of Oil and Gas Conservation
2535 St. Johns Ave
Billings, MT 59102

Dear Board Members,

My name is Anne Moses. In July 2016 I signed the petition to reform the Montana Board of Oil and Gas Conservation's fracking chemical disclosure rules because it is critical to our health and welfare that we have greater access to fracking chemical information. Today I ask again that you take responsible action on this matter before you.

Along with my three sisters, I own property on the banks of the Stillwater River approximately fifteen miles upstream from Absarokee, Montana. My parents bought the cabin property in the mid-1970s. They later added to the cabin and moved there full-time in the mid-1980s, residing there until their deaths roughly ten years ago. Since that time, my husband, children and I, as well as my sisters and their families, have continued to spend significant parts of the spring, summer, and fall there. My husband, David Katz, and I spend about three to four weeks there each year. We also periodically rent the cabin to vacationers when the family is not there.

My family does not own the mineral rights on our property, so we could not prevent or control oil and gas development there.

The things I value most about our family property on the Stillwater River are the river itself and the surrounding environment. The river is the biggest attraction. A passion for fishing has been part of my family for generations. My parents taught me to fly-fish in Montana when I was a young girl, and with these lessons they also gave me a reverence for the rare and precious pure waters of Montana. In turn, I taught my three sons how to fish and how to respect and conserve the local streams, including the Stillwater River and its tributaries. We all enjoy fishing in the river and my family goes rafting and tubing as well. The surrounding landscape—the foothills of the Custer National Forest and lower-lying ranchlands—is beautiful and peaceful. The water we use for drinking and domestic purposes comes from a well on our property. We use river water to irrigate our property. The water from our well is delicious and pure. In fact, I remember my father getting the quality of our well water tested every year and bragging about its purity. He passed that pride in our water on to me.

I first became concerned about the impact of extractive industry on our family land when my parents became involved in public debate surrounding the Stillwater Mine, which is just a few miles from our property. I became concerned about mine safety as well as the potential for contamination—particularly the potential for mine tailings to contaminate nearby groundwater. As the North Dakota fracking boom picked up speed in the past decade, I also became concerned about the potential for oil and gas development in our area. These concerns intensified when Energy Corporation of America announced in 2013 that it wanted to bring “something like the Bakken” boom to the Stillwater Valley and other areas along the Beartooth Front. At that time, I began educating myself about fracking and my husband and I became involved in local efforts to protect the Stillwater River, our property, and the surrounding environment from contamination and other harm threatened by oil and gas development.

As I learned more about fracking and how it is regulated, I was horrified to discover how little control governments exert over the industry and the scant protections for local people, land, livestock, and livelihoods. My concerns about the potential harm to our family property and the local environment became more urgent when Energy Corporation of America drilled a test well in neighboring Carbon County in 2014.

I am very concerned about the risk of fracking contaminating the Stillwater River, the well on our property, or the groundwater system in our area. We depend entirely on clean water to use and enjoy our cabin—we use the well for drinking, cooking, and bathing, and we rely on the river for irrigation and recreation. I also am concerned about the risk of harm to fish and other wildlife from contamination of the local watershed. If our well or the river near our land were contaminated, our whole reason for being there would be poisoned and our investment in our property would be damaged or destroyed. We would be unable to rent our cabin to vacationers in the area because it would be completely undesirable. Water contamination in our area also would threaten the livelihoods of our friends and neighbors who ranch nearby.

I want to be able to research the environmental and health effects of the specific chemicals proposed for use on or near our land so I can understand the risks, including the risks of toxic exposure for me and my family. I also want access to specific chemical information so I can effectively test the quality of the well water on our family property before fracking occurs and monitor it afterwards for evidence of contamination. Likewise, the river water should be tested before and after any oil and gas activity. We need to know what to test for in order to determine if we have or might be harmed, and we cannot get this information now. I believe it is critical for individuals to have direct access to this information so they can decide how best to protect their property and their health.

Action by the Board of Oil and Gas Conservation to make rules regarding fracking chemical disclosure and require greater disclosure of fracking chemical information would be an essential public service. This would help protect my interests in safeguarding the water and surrounding environment on my family property on the Stillwater River, and in understanding the risks to my family and our property from fracking operations in our area.

Sincerely,

Anne B. Moses
1473 Stillwater River Road
Nye, MT 59061

550 Elbow Creek Road
Roberts MT 59070

January 25, 2017

Montana Board of Oil and Gas
2535 St. Johns Avenue
Billings, MT 59102

Dear colleagues,

I would like to express my appreciation for the Board's decision to reconsider our rulemaking petition concerning fracking disclosure. My concerns about this issue are both personal and professional.

I was raised on a ranch in Richland County, and have family still living there. We have several active oil wells on this family property that have been fracked. Observations several years ago of the various processes used in drilling the wells left me very concerned about the possible toxicity of the chemicals used. Accidents happen, and we have no way of knowing what may be happening to the land as a result of the oil drilling and fracking operations there, including the pollution that may be left behind when all that oil has been extracted. Another reason for my personal interest is that my husband and I have ranch property near Roberts, which is a setting of potential oil drilling activity.

But I am also concerned about the possible impacts of fracking because of my public health background. I have doctoral and masters degrees in public health and I teach on the topic of maternal and newborn health at the university level. From a public health perspective, the potential exposure to large numbers of unknown and possibly toxic chemicals used in the fracking process could be a significant problem. I don't think we currently have enough information on the chemicals being used to assess the hazards they may pose to the quality of surface water, ground water, human health, and the environment overall. The petition that we have submitted aims to improve our ability to assess those risks.

I am confident that as the responsible body for overseeing oil development in Montana, the Board will take every reasonable precaution to minimize the damaging effects of fracking chemicals on human health. Thank you again for your decision to reconsider out petition.

Sincerely,

Mary Anne Mercer

Mary Anne Mercer, DrPH

Montana Board of Oil and Gas Conservation
2535 St. Johns Avenue
Billings, MT 59102

January 26, 2017

Re: Rulemaking on Hydraulic Fracturing Chemical Disclosure

To the Members of the Montana Board of Oil and Gas Conservation:

My name is Willis D. Weight. I have a Ph.D. in mathematical geology and I am a certified Professional Engineer in the State of Montana, practicing since 1992. My academic and professional background is in earth sciences and engineering, and I have nearly thirty years of experience with water contamination issues.

I began teaching in the department of geological engineering at Montana Tech in Butte in 1989 and subsequently served as head of the department. During my twenty-year tenure at Montana Tech, I taught undergraduate and graduate-level courses in geology, hydrogeology, groundwater monitoring, contaminant transport modeling, and field methods. I have written two books on field hydrogeology for McGraw-Hill publishing and am currently working on a book proposal for a 3rd Edition. For the past nine years, I have taught at Carroll College in Helena, where I have developed the environmental engineering program in the engineering department and have served as head of the environmental studies program for three years. I currently teach classes in hydrology, hydrogeology, water quality, public health and the environment, air quality, groundwater modeling, and field methods.

Since 1989 I also have operated as President of a consulting business providing groundwater studies for landowners and expert witness support in a variety of water cases.

In 2015, I co-authored a white paper entitled "Fracking in Montana: Asking Questions, Finding Answers," which was funded by the Montana Farmers Union and aimed to provide a Montana-focused perspective on fracking and its potential impacts. I authored the paper's chapters on water quantity, water quality, and air quality impacts.

Through my work on the white paper and other research, I have developed a number of concerns about the potential environmental and public health impacts of fracking in Montana. As a result, I am supportive of the Board's decision to take a second look at the need for rulemaking to expand public access to information about the chemicals used for hydraulic fracturing, or "fracking," in our state. The issue of fracking chemical disclosure is of vital importance to Montana landowners and citizens who live, work, farm, and ranch near oil and gas operations.

Approximately 0.5-1.5% of the fracking fluid volume is composed of chemical additives, meaning that tens of thousands of gallons of chemical additives are used for each fracking job. According to the U.S. Environmental Protection Agency, at least 1,076 different chemicals are used in fracking fluids, including acids, volatile organic chemicals, alcohols, surfactants, and hydrocarbons. A number of these chemicals are known human carcinogens. However, the contents of the chemical cocktail used to frack a particular well are often not disclosed to the public because of industry claims that the chemical ingredients constitute "trade secrets."

There are many pathways for fracking chemicals to contaminate surface water and groundwater supplies; including surface spills of fracking fluids, flowback and produced water, blowouts, poorly maintained surface pits, and improper well completion that leads to well casing failure.

I also have concerns about the quantity of water used for fracking. Several million gallons of water are used for each fracking job. In Montana, fracking uses over 2.5 times more groundwater than all livestock uses state-wide. Because chemicals—including some that are carcinogenic or toxic—are added to the water used for fracking, this water is effectively removed from the usable water budget. Given the hydrological conditions in Montana as a headwater state, I am concerned about whether we will have adequate clean water to satisfy our other needs, over the long-term, given the substantial demand fracking places on our water resources.

I am also concerned about several air quality impacts from fracking. First, I am concerned about the potential for workers and nearby residents to be exposed to silica dust—a primary component of proppants used for fracking—and other chemicals, some of which are associated with skin and respiratory problems, are carcinogenic, or are mutagenic. I also have concerns about methane flaring, which has both local air quality impacts and climate impacts.

I signed the rulemaking petition to reform the Board's fracking chemical disclosure rules in July 2016 because I believe that broader public access to information about the specific chemicals used for fracking operations is critical to protect landowners' interests and public health. Landowners cannot effectively establish a baseline quality of water sources they rely on for stock watering, irrigation, and domestic purposes without knowledge of the specific chemicals proposed for use on or near their property. Access to fracking chemical information is also important for ongoing research into public health impacts.

As a private consultant, I work with landowners concerned about petroleum hydrocarbon contamination, including activities associated with preparing baseline water-quality studies. I need to have access to comprehensive information identifying the chemicals used for fracking on or near my clients' property to conduct the most effective studies possible.

The Board has undisputed authority to do the right thing by reforming its rules to provide greater public disclosure of fracking chemical information. I ask that the Board take this opportunity to do so by granting the rulemaking petition and reforming the flawed aspects of its existing disclosure rules as requested in the petition.

Sincerely,

Willis D. Weight, PhD PE

PLUGGING PROJECTS & FIELD INSPECTOR SUMMARY

February 2, 2017

Inspector Training:
Scheduled for this year will be the annual H2S re-certification course. State Lands personal also attend the H2S course held here at the billings office. New this year the inspectors will be attending 811 One Call training. This training is presented throughout the state and the inspectors will be able to attend a class near their home towns. John Gizicki and Dave Popp attended the class presented January 17th here in Billings. There will be a driving class included again this year. Training schedules haven't been released yet.

Orphaned Well Flack #1:
Contract is in place with an ending date of June 30, 2017. Weather has delayed the start of the project as a large amount of precipitation has been received in the area. Exploratory work was completed November 4, 2016 and work to plug and reclaim the well will commence as soon conditions allow.

Orphaned Wells Kendrick #3, State E-2, Sprinkle #1:
The wells in this project where combined into a 3 well package. The contract has an ending date of April 1, 2017. The Kendrick #3 in Big Horn County was plugged December 1, 2016. Reclamation will be completed spring 2017. The next well in line to be plugged will be the State E-2 in Musselshell County followed by the Sprinkle #1 in Blain County when weather permits.

Orphaned Well Beery 22-24:
Plugging and reclamation of this well is the planning stages. The procedure and cost associated to plug the well are complete. Costs associated with the reclamation are not complete. Ownership of surface and downhole equipment remains to be determined. McCone County claims there are no current tax liens on the personal property.

GRANT BALANCES - 1/26/2017	Amount	Expended	Balance	Expiration Date	Status
2015 Kopp #1 RIT-13-8753	106,408	106,408	0	9/30/2016	**Completed**
Big Wall Tank Battery RIT 12-8723	38,239	38,239	0	9/30/2016	**Completed**
Total	**144,647**	**144,647**	**0**		

2016 PLUGGING & RECLAMATION PROJECTS	CONTRACT & BALANCES - 1/26/2017	Amount	Expended	Balance	Reverted Balance	Fund	Expiration Date	Status	Ranking	Comments
Kopp #1 (Berco Resources)	Liquid Gold Well Service Inc., OG-LG-155	18,451	18,451	0	0	RIT-12-8723	12/31/2015	**Completed**	12	Install Well Control Equipment Completed 12/23/15
	Liquid Gold Well Service Inc., OG-LG-156	24,864	17,090	7,774	7,774	Damage Mitigation	6/30/2016	**Completed**	12	Install No-Weld Control Equipment Completed 2/10/16
	Liquid Gold Well Service Inc., OG-LG-158	263,930	249,938	13,992	13,992	RIT 13-8753 & Damage Mitigation	11/1/2016	**Completed**	12	Plugging & reclamation completed 8/30/16
	Total	**307,244**	**285,479**	**21,766**	**21,766**					
Kelly #1 (The Ranch)	Liquid Gold Well Service Inc., OG-LG-157	19,360	12,744	6,616	6,616	Damage Mitigation	12/31/2016	**Completed**	11	Project completed 6/15/16
Flack #1 (Williston Oil & Gas)	Liquid Gold Well Service Inc., OG-LG-159	45,493	2,708	42,785		Damage Mitigation	6/30/2017	Contracted	12	Plug and reclaim (Work in progress, will need to extend contract)
State E-2 (UIC) (Kelly Oil & Gas)	Liquid Gold Well Service Inc., OG-LG-160	77,575	0	77,575		Damage Mitigation	4/1/2017	Contracted	UIC	Plug and reclaim
Sprinkle #1 (Montana Canadian)	Liquid Gold Well Service Inc., OG-LG-160	18,615	0	18,615		Damage Mitigation	4/1/2017	Contracted	11	Plug and reclaim
Kendrick #3 (Rocky Mountain Operating)	Liquid Gold Well Service Inc., OG-LG-160	81,314	62,507	18,807		Damage Mitigation	4/1/2017	Contracted	10	Plug and reclaim (Work to this well currently in progress)
	TOTAL	**177,504**	**62,507**	**114,997**						
Big Wall Tank Battery	Brewer Inc., OG-CB-156	39,239	18,451	20,788	0	RIT 12-8723	9/30/2016	**Completed**		Completed 9/19/16; $20,788.11 was purposed to the Kopp#1 well
	Total	**588,839**	**381,888**	**206,952**	**28,382**					

Montana Board Of Oil and Gas

Orphan Well List, by Rank

1/31/2017

08321082 BERCO RESOURCES, INC. KOPP 1 Twp: 24 N Rge: 57 E Sec: 10 W2 NE SW — Funding Approved ☑

Required: Plugging and Restoration Performed: Well Status: 12 Well Location: 1 **Ranking: 13** — DMA Candidate ☐

Comments: Abandoned well with cut off casing. Oil stain at surface, and upon excavation a casing stub leaking oil, water, and gas with minor H2S. Will require re-entry and replugging. — Pending Grant Application ☐

01505050 WILLISTON OIL & GAS FLACK 1 Twp: 28 N Rge: 11 E Sec: 12 NE NE SE — Funding Approved ☑

Required: Plugging and Restoration Performed: Well Status: 10 Well Location: 2 **Ranking: 12** — DMA Candidate ☐

Comments: Old dry hole from 1928 leaking wtr to sfc alongside 12-3/4" csg that extends 4' above sfc on winter wheatfield. Two large pits built to contain waters from slow leak to sfc. Well is in SESENE and not NENESE as indicated by records. Old wire rope, bricks, wood and oilfield debris exists on-site along w/a farmer's rockpile garbage pit at SW end of site. Periodic gas bubbles seen coming up thru water alongside well. — Pending Grant Application ☐

00305205 ROCKY MOUNTAIN OPERATING CO., INC. KENDRICK 3 Twp: 1 S Rge: 35 E Sec: 6 NW NW NW — Funding Approved ☑

Required: Plugging and Restoration Performed: Well Status: 10 Well Location: 1 **Ranking: 11** — DMA Candidate ☐

Comments: Oil well shut in with equipment, rods, tubing and pump jack. Well pressured up. No pits.
Originally funded under 2007 Southern Grant but landowner requested it no be plugged.
Landowner now requests that the well be plugged. — Pending Grant Application ☐

00505020 MONTANA CANADIAN OIL CO. SPRINKLE 1 Twp: 31 N Rge: 20 E Sec: 19 E2 SE SW — Funding Approved ☑

Required: Plugging and Restoration Performed: Well Status: 10 Well Location: 1 **Ranking: 11** — DMA Candidate ☐

Comments: Wellhead, 7" casing with slow flow of water. Well located at the edge of crop land. Eagle top at 600' according to well records. — Pending Grant Application ☐

06505288 KELLY OIL AND GAS LLC STATE E-2 Twp: 11 N Rge: 30 E Sec: 36 — Funding Approved ☑

Required: Plugging and Restoration Performed: Well Status: 10 Well Location: 1 **Ranking: 11** — DMA Candidate ☐

Comments: Bond Forfeited by Board Order 189-2015
Inspection report and ranking completed 3/15/2016 by Fraser
PLUGGING REQUIRED UNDER UIC PROGRAM - FAILED MIT — Pending Grant Application ☐

06921051 ALPHA PETROLEUM CORP. & JAMES C. LA ARB 1 Twp: 13 N Rge: 28 E Sec: 26 C NE NE — Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 10 Well Location: 1 **Ranking: 11** — DMA Candidate ☐

Comments: Well shown as P&A approved. 8-5/8" csg w/wellhead at sfc. 4-1/2" csg thru sfc head and used as dry hole monument. Well inspection in 1998 shows same condition as present condition. Above ground monument has a pipe clamp at approximately eye level and has apparently leaked at that level previously. There is a corrosion hole in 4-1/2" at the level of the sfc head. Water is at the level of the hole and standing. Appears to periodically leak from hole out to sfc of the location. Vegetation is dead around wellhead. Deadmen installed. Viewed well at the request of the land owner, Dustin Ingersol. Water is entering the 4-1/2" csg and rising to the sfc. Question the integrity of the cmt job or the CIBP. — Pending Grant Application ☐

05505097 NATIVE AMERICAN ENERGY GROUP, INC. BEERY 22-24 Twp: 23 N Rge: 49 E Sec: 24 C SE NW — Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 5 **Ranking: 8** — DMA Candidate ☐

Comments: Inspection 10/9/2012 RP
No pumping unit, rods and tubing in well; production tanks, treater, pumping unit off well
Lots of junk iron, wood and pipe on location. Flare pit.
Native American Energy Group, Inc. bond forfeited June 6, 2013. — Pending Grant Application ☐

08321346 ALTURAS ENERGY LLC CARLSEN-LYCHE 22-12 Twp: 23 N Rge: 59 E Sec: 22 SW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 5 **Ranking: 8** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned well inspection report completed 3/21/16
Surface owner plans to install center-pivot sprinkler.

10106012 HESLA OIL CO MCMANUS 12 Twp: 35 N Rge: 2 W Sec: 21 SE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 5 **Ranking: 8** DMA Candidate ☐

Comments: Added based upon 3/8/1999 inspection; unplugged well with rods & tubing. Pending Grant Application ☐
Updated inspection report 1/2/2008 by Bill Halvorson indicates rods & tbg removed, could be a fish in the well?, wellbore open to the atmosphere.

10110309 DANIELSON, PATRICIA, OIL DANIELSON 1 Twp: 35 N Rge: 1 W Sec: 21 NE SW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 5 **Ranking: 8** DMA Candidate ☐

Comments: Old SIOW with rods and tubing. No pumping unit. Open pit and trench. Site needs major cleanup. Farm house within 1/4 mile. Pending Grant Application ☐

02106236 EASTERN MONTANA OIL & GAS CO. MONT-DAK 11 (210) Twp: 14 N Rge: 55 E Sec: 20 NE NE Funding Approved ☐

Required: Surface Restoration Performed: Well Status: 6 Well Location: 1 **Ranking: 7** DMA Candidate ☐

Comments: Pending Grant Application ☐

06521073 KELLY OIL AND GAS LLC WSW #1 Twp: 11 N Rge: 30 E Sec: 36 SE NW SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 6 Well Location: 1 **Ranking: 7** DMA Candidate ☐

Comments: Bond forfeited by Board Order 2-2016. Pending Grant Application ☐
Open production casing, no wellhead,open orbit valve, no flow fluid approximently 400' from the surface.

08321350 ALTURAS ENERGY LLC ANDREW PETERSEN 28- Twp: 22 N Rge: 59 E Sec: 28 W2 NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 5 **Ranking: 7** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned well inspection report completed by Utter 3-21-16

08321292 ALTURAS ENERGY LLC CARLSEN-LYCHE 21-41 Twp: 23 N Rge: 59 E Sec: 21 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 5 **Ranking: 7** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned inspection report completed by Utter 3/21/16

08321294 ALTURAS ENERGY LLC SCHEETZ 21-1 Twp: 22 N Rge: 59 E Sec: 21 SW SE SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 5 **Ranking: 7** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned well inspection report completed by Utter 3/21/16

08321506 ALTURAS ENERGY LLC BASS-MARKER 20-33 Twp: 22 N Rge: 59 E Sec: 20 C SE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 5 **Ranking: 7** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned well inspection completed by Utter 3-21-16

08321769 ALTURAS ENERGY LLC DEGN 29-44 Twp: 22 N Rge: 59 E Sec: 29 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 5 **Ranking: 7** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 165-2015 Pending Grant Application ☐
Orphaned well inspection report completed by Utter 3-21-16

05521124 NATIVE AMERICAN ENERGY GROUP, INC. BEERY 2 Twp: 23 N Rge: 49 E Sec: 24 S2 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 4 Well Location: 2 **Ranking: 6** DMA Candidate ☐

Comments: Inspection 10/0/2012 RP Pending Grant Application ☐
Tubing and rods laid out next to well. Assume 3 joints tubing in wellhead, not a full string. Well is capable of flowing.
Flowline has leaked in the past. Well currently shut in at the wellhead.
Wellsite has vegetation, junk, wood, barrels, pipe and fittings scattered about. Tubing and rods.
Production tanks, no treater, pumping unit.
1-Flare pit.
1-Emergency catch pit next to flowline leak.
Native American Energy Group, Inc. bond forfeited at Board of Oil & Gas "Show Cause" hearing June 6, 2013.

05105069 THOMPSON, C.H. THOMPSON 1 Twp: 34 N Rge: 4 E Sec: 7 NE SW SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 2 **Ranking: 5** DMA Candidate ☐

Comments: Pre-regulatory well located in farmed field, 6 5/8" casing w/home made wellhead and brass valve, cable remains laying on the surface. Pending Grant Application ☐

05121447 BURTON/HAWKS INC SHETTEL 1 Twp: 32 N Rge: 6 E Sec: 1 C SW Funding Approved ☐

Required: Surface Restoration Performed: Well Status: 3 Well Location: 2 **Ranking: 5** DMA Candidate ☐

Comments: Located in farmed fields, well properly plugged, small stipper facility remains site to restore measures 40'x100', concrete bases remain, rig anchors. Pending Grant Application ☐

07305092 RUDI & ASSOCIATES LEDERER "B" 13 Twp: 27 N Rge: 3 W Sec: 18 NW SE SW Funding Approved ☐

Required: Surface Restoration Performed: Well Status: 3 Well Location: 2 **Ranking: 5** DMA Candidate ☐

Comments: Well plugged and farmed over, old tank battery remains, 20'x20'x4' pit, loose pipe scattered pipe,wod, 4 telephone poles, significant cleanup required. Pending Grant Application ☐

07521766 COLUMBUS ENERGY CORP. ANNA POWELL 9-9-53-10 Twp: 9 S Rge: 53 E Sec: 9 C NW SE Funding Approved ☐

Required: Surface Restoration Performed: Well Status: 4 Well Location: 1 **Ranking: 5** DMA Candidate ☐

Comments: Well leaking water between surface casing and production casing strings. Assume water is coming from Fox Hills formation. Pending Grant Application ☐
Water is fresh. Well is plugged down production casing. Dryhole marker set.
Inspected 6/24/07, Hystad.
Inspection 2/18/15, Popp/Mercier. This well is included in the 2015 Southern District grant application.

08521678 MSC EXPLORATION LP 20105 JV-P LOCKMAN 1 Twp: 28 N Rge: 51 E Sec: 19 NW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 3 **Ranking: 5** DMA Candidate ☐

Comments: Shut in gas well. Pending Grant Application ☐
MSC Exploration LP bond forfeited by Order 258-2011, done August 11, 2011.
Located in grass land, wellhead equipment, rods, 2 3/8" tubing, pump and anchor, rig anchors.

08521679 MSC EXPLORATION LP 20105 JV-P CLARK 1 Twp: 29 N Rge: 50 E Sec: 29 SW SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 3 **Ranking: 5** DMA Candidate ☐

Comments: Shut in gas well.
MSC Exploration LP bond forfeited by Order 258-2011, done August 11, 2011.
Wellhead, rods, 2 3/8" tubing, pump and anchor. Rig anchors, Surface use is farmed field
Pending Grant Application ☐

10100001 Twp: Rge: Sec: Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: Well Location: **Ranking: 4** DMA Candidate ☐

Comments: UNIDENTIFIED GAS WELL, N/2 NE SE SW 15-34N-1W, APPROX. 1150 FSL & 2300 FWL; 7" CSG ABOVE GROUND, FLOWLINE; OPEN 8 5/8 W/ PLUG LOCATED SHORT DISTANCE AWAY
Pending Grant Application ☐

01921095 NORTH AMERICAN TECHNICAL TRADING FUGERE 4-19 Twp: 34 N Rge: 48 E Sec: 19 SW SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in oil well. Operator forfeited bond by Order 255-2011, done August 11, 2011.
All equipment sold at Sheriff's auction. All equipment removed from location.
Wellhead, tubing, no rods.
No pits. 4 rig anchors on location.
Pending Grant Application ☐

02505106 MONARCH OIL & GAS WM WAGNER 2 Twp: 5 N Rge: 60 E Sec: 5 C SW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Inspected DH 6/22/09. Production casing with valve.
Within 1/4 mile of surface water. Surface ok, hay field

2013 Southern District Orphaned Well P&A grant.
Pending Grant Application ☐

02705158 EMMONS ETAL NORHEIM 3 Twp: 21 N Rge: 18 E Sec: 5 W2 NW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** DMA Candidate ☐

Comments: Shut in gas well. Low pressure well 16 psig according to file information. 12 1/2" casing swedged to 2" and valved at the surface.

Surface owner claims wells,Duane Kucera and two other wells nearby. Fraser 4/12/10.
Pending Grant Application ☐

03505040 PARDUE A R ANDERSON #1 Twp: 32 N Rge: 5 W Sec: 31 C SE SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: 13 3/8 in casing at 18" below GL. No Leaking. Collar looking up. Near 15 sec for rock to hit solid. Site on cropland stubble. No record of being plugged. Inspected by Bill Halvorson 5/29/2014.
Pending Grant Application ☐

04105070 BRONSON, C.R. AGORETTA 1 Twp: 34 N Rge: 17 E Sec: 33 NW NW SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** DMA Candidate ☐

Comments: Wellhead remains, no leaks. Site on grass/pasture land.
Pending Grant Application ☐

04160027 INDEPENDENT NATURAL GAS CO. AULT 1 Twp: 32 N Rge: 17 E Sec: 8 SE SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** DMA Candidate ☐

Comments: Well head, no pit, no leaks, and minor refuse
Pending Grant Application ☐

07305420 NORTHERN ORDINANCE, INC. JANNUSCH 1 Twp: 28 N Rge: 7 W Sec: 13 NE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** DMA Candidate ☐

Comments: This well is open at the surface, required a cement surface plug and the casings cut-off and buried. Pending Grant Application ☐

07522244 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 1P Twp: 5 S Rge: 48 E Sec: 18 NE NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad.. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District grant request.

07522245 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 2P Twp: 5 S Rge: 48 E Sec: 18 SW SW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad.. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District Orphaned Well P&A grant request.

07522246 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 3P Twp: 5 S Rge: 48 E Sec: 18 NE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad.. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District Orphaned Well P&A grant request.

07522247 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 4P Twp: 5 S Rge: 48 E Sec: 18 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad.. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District Orphaned Well P&A grant request.

07522248 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 5AP Twp: 5 S Rge: 48 E Sec: 18 NW SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District Orphaned Well P&A grant request.

07522255 ROCKY MOUNTAIN GAS, INC. CASTLE ROCK 6AP Twp: 6 S Rge: 48 E Sec: 18 SE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** DMA Candidate ☐

Comments: Shut in CBM well with downhole equipment. Surface owner does not want to acquire per field inspector Hystad. Pending Grant Application ☐
Bond Forfeited by Order 87-2010, done April 29, 2010.

Included in the 2015 Southern District Orphaned Well P&A grant request.

08321511 ALTURAS ENERGY LLC SUNDHEIM 14-15 Twp: 24 N Rge: 59 E Sec: 15 C SW SW — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** — DMA Candidate ☐
Comments: Bond Forfeited by Board Order 165-2015 — Pending Grant Application ☐
Orphaned well inspection report completed by Utter 3/21/16

08321352 TENNECO OIL COMPANY OBERGFELL 1-33 Twp: 23 N Rge: 57 E Sec: 33 SE SE — Funding Approved ☐
Required: Surface Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** — DMA Candidate ☐
Comments: Natural spring or seep appears to be impacted by drainage from reserve pit; (MBMG review of water analysis). — Pending Grant Application ☐

08521020 NATIVE AMERICAN ENERGY GROUP, INC. MASON 7-16 Twp: 29 N Rge: 50 E Sec: 7 SE SE — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate ☐
Comments: Operator defaulted on bond. — Pending Grant Application ☐
Native American Energy Group, Inc. acquired mineral lease under this well and filed a "Change of Operator", 12/20/05.
Native American Energy Group, Inc. bond forfeited at Board of Oil & Gas "Show Cause" hearing June 6, 2013.
located in farmed field, wellhead, production string (rods & pump), rig anchors, misc. pipe laying on the surface

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08521709 PRODUCED WATER SOLUTIONS, INC. BRISKE 4-9H Twp: 29 N Rge: 58 E Sec: 9 NW NW — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate ☐
Comments: Bond Forfeited 10/16/14, Entered into orphane data base 7/20/15 by DLP — Pending Grant Application ☐
Intact wellhead, production string (rods & tubng), anchors, electrial service. No known down hole issues No tank battery or pits.

10105444 ROSSMILLER, DUARD & ELMER ROSSMILL ADAMS 9 Twp: 34 N Rge: 2 W Sec: 12 C NE SE — Funding Approved ☐
Required: Surface Restoration Performed: Well Status: 1 Well Location: 3 **Ranking: 4** — DMA Candidate ☐
Comments: Appears P&A'd - assumed properly. 2 ft sunken hole where casing was believed burried. No leaking evident. Evap pit turned to garbage pit. Lots of debris/garbage. Signifigant cleanup needed. — Pending Grant Application ☐

10106034 ADAMS-HESLA OIL MCMANUS 6 Twp: 35 N Rge: 2 W Sec: 21 S2 SE SE — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate ☐
Comments: Added based upon 3/11/1999 inspection; casing w/ wellhead, small pit, tools & equipment on location. — Pending Grant Application ☐

10106323 COBB-COOLIDGE DAVIES 1 Twp: 35 N Rge: 4 W Sec: 24 NE NE NE — Funding Approved ☐
Required: Surface Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** — DMA Candidate ☐
Comments: Located on gressland, well properly plugged, casings not cut off and remain above ground level, concrete pump hjack pad and cellar remain, significnt cleanup remains to be done. — Pending Grant Application ☐

10111336 AGEN, J. H. GOEDDERTZ 1 Twp: 35 N Rge: 3 W Sec: 26 NE NW SW — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** — DMA Candidate ☐
Comments: 8 5/8 casing 1 ft above surface that is open. Not leaking. Possibel fill/plug 20 ft down. Some minor debris on site. Mound of drill cuttings nearby. — Pending Grant Application ☐

10111743 UNKNOWN UNKNOWN UNKNOWN Twp: 35 N Rge: 2 W Sec: 11 W2 SE SE — Funding Approved ☐
Required: Plugging and Restoration Performed: Well Status: 3 Well Location: 1 **Ranking: 4** — DMA Candidate ☐
Comments: Open 6 5/8" casing 1 ft above surface. 2 ft down has mushy/old drilling fluid in hole. 40' east of well is small sunken pit area. Sfc restored, on grassland. — Pending Grant Application ☐

10521278 NATIVE AMERICAN ENERGY GROUP, INC. SANDVICK 1-11 Twp: 31 N Rge: 44 E Sec: 11 SW NW — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate [ ]

Comments: Native American Energy Group, Inc. bond forfeited at Board of Oil & Gas "Show Cause" hearing June 6, 2013. Pumping unit w/electric motor, wellhead, production string (rods & tubing), treater, transfer pump, recycle pump, tubing on surface, rig anchors, 2- 400 bbl tanks, 2- 300 bbl fiberglass tanks. — Pending Grant Application [ ]

10921041 CUSTOM CARBON PROCESSNG, INC. WOJAHN "A" 5-2 Twp: 13 N Rge: 60 E Sec: 2 S2 SW NW — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate [ ]

Comments: Bond Forfeited by Board Order 192-2015, UIC Permit #MT5314 — Pending Grant Application [ ]

10921048 CUSTOM CARBON PROCESSNG, INC. MICHELS "A" 8-3 Twp: 13 N Rge: 60 E Sec: 3 S2 SE NE — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 2 **Ranking: 4** — DMA Candidate [ ]

Comments: Bond Forfeited by Board Order 192-2015, The ranking of this well does not reflect the trash cleanup requied. Cost estiments to cleanup the trash on location total $18,000.00. — Pending Grant Application [ ]

01921096 SUMMER NIGHT OIL COMPANY, LLC ANDERSON 27-1 Twp: 33 N Rge: 48 E Sec: 27 NW NW — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** — DMA Candidate [ ]

Comments: SI oil well, Operator forfeited bond by Order 169-2014 done November 19, 2014 Located in grassland. Treater, propane tank, recycle pump, 3-400 bbls tanks and a building, rig anchors small pit remain. Wellhead, tubing downhole. — Pending Grant Application [ ]

01921099 SUMMER NIGHT OIL COMPANY, LLC ANDERSON 27-2 Twp: 33 N Rge: 48 E Sec: 27 NE NW — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** — DMA Candidate [ ]

Comments: SI oil well, Operator forfeited bond by Order done 11/19/14 located I grass land, wellhead and tubing, small chemical tank, rig anchors — Pending Grant Application [ ]

01921130 NORTH AMERICAN TECHNICAL TRADING GENDREAU 1-24 Twp: 34 N Rge: 47 E Sec: 24 SW NE — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** — DMA Candidate [ ]

Comments: Shut in oil well. Operator forfeited bond by Order 255-2011, done August 11, 2011. All equipment sold at Shieriff's auction. All equipment removed from location. No pits. 4 rig anchors — Pending Grant Application [ ]

01921139 MIOCENE OIL COMPANY SUMMER NIGHT 21-1 Twp: 33 N Rge: 48 E Sec: 21 NE NE — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** — DMA Candidate [x]

Comments: Bond forfeited by Board Order 1-2016, Inspection report completed by Schmidt 8/2/16. rods, tubing, pump in hole. Pumping unit , gas motor, tank battery , along with out buildings remain on location. Photos attached to inspection report. — Pending Grant Application [ ]

01921075 NORTH AMERICAN TECHNICAL TRADING SATURN STATE 1 Twp: 34 N Rge: 47 E Sec: 24 NW NW — Funding Approved [ ]

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** — DMA Candidate [ ]

Comments: Shut in oil well. Operator forfeited bond by Order 255-2011, done August 11, 2011. All equipment sold at sheriff's auction. All equipment removed from location. One small pit on location, 4 rig anchors. — Pending Grant Application [ ]

01921084	NORTH AMERICAN TECHNICAL TRADING	FUGERE 1	Twp: 34 N	Rge: 48 E	Sec: 30 NW NW		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Shut in oil well. Operator forfeited bond by Order 255-2011, done August 11, 2011. All equipment sold at Sheriff's auction. Wellhead, tubing, no rods. No pits. 4 rig anchors.							Pending Grant Application ☐
01921085	NORTH AMERICAN TECHNICAL TRADING	FISHER 1-24	Twp: 34 N	Rge: 47 E	Sec: 24 SE SW		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Shut in SWD, injection well. Operator forfeited bond by Order 255-2011, done August 11, 2011. All equipment sold at Sheriff's auction. All equipment removed from location. No pits. 4 rig anchors							Pending Grant Application ☐
01921091	NORTH AMERICAN TECHNICAL TRADING	FUGERE 3-30	Twp: 34 N	Rge: 48 E	Sec: 30 SE NW		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Shut in SWD. Operator forfeited bond by Order 255-2011, done August 11, 2011. Building over wellhead. 4 rig anchors. Wellhead & tubing downhole.							Pending Grant Application ☐
06505262	KELLY OIL AND GAS LLC	BUTTS 4 (5-4)	Twp: 10 N	Rge: 30 E	Sec: 1 NE SE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Bond forfeited by Board Order 2-2016. Unplugged well with intact wellhead, 2 7/8" tubing, rods hanging in well, Pumping unit American 160.							Pending Grant Application ☐
06505270	KELLY OIL AND GAS LLC	BUTTS 5-3 (3)	Twp: 10 N	Rge: 30 E	Sec: 1 SE NE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Bond forfieted by Board Order 2-2016. Unplugged well with intact wellhead, 2 7/8" tubing, no rods, pumping unit National 228D, parats of an old American pumping unit on location, new rods laying on the surface.							Pending Grant Application ☐
06505275	KELLY OIL AND GAS LLC	BUTTS 5-1 (1)	Twp: 10 N	Rge: 30 E	Sec: 1 NE NE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Bond forfited by board order 2-2016. Unplugged well with wellhead, 2 7/8" tubing, rods, pumping unit Bethleham 114D, some tubing laying on the surface.							Pending Grant Application ☐
06505285	KELLY OIL AND GAS LLC	STATE E-1 (4-1)	Twp: 11 N	Rge: 30 E	Sec: 36 SW SE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Bond forfeited by Board Order 2-2016. unplugged well with intact wellhead,2 3/8" tubing, rods hanging in well, pumping unit Bethlehem 160D, single pole pulling unit on lacation.							Pending Grant Application ☐
06505286	KELLY OIL AND GAS LLC	STATE 2-2 (F-2)	Twp: 11 N	Rge: 30 E	Sec: 36 SE SW		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status: 2	Well Location: 1		Ranking: 3	DMA Candidate ☐
Comments: Bond forfeited by Board Order 2-2016. Unplugged well with intact wellhead, 2 3/8" tubing, rods hanking in well, pumping unit Bethlehem 114D, 300 bbl tank.							Pending Grant Application ☐

06505443 KELLY OIL AND GAS LLC STATE 1 Twp: 11 N Rge: 30 E Sec: 16 NW NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 189-2015 Pending Grant Application ☐
Inspection report and ranking completed 3/15/2016 by Fraser

06505460 KELLY OIL AND GAS LLC SHELHAMER A-4 Twp: 11 N Rge: 30 E Sec: 8 C SE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Bond forfeited by Board Order 2-2016. Pending Grant Application ☐
Intact wellhead with 2 7/8" tubing in well.

06505478 KELLY OIL AND GAS LLC R. SHELHAMER 1A Twp: 11 N Rge: 30 E Sec: 8 C NE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Bond Forfeited by Board Order 189-2015 Pending Grant Application ☐
Inspection report and ranking completed by Fraser 3/15/2016

06505585 KELLY OIL AND GAS LLC BUTTS 5-5 (5) Twp: 10 N Rge: 30 E Sec: 1 SE SE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Bond forfeited by Board Order 2-2016. Pending Grant Application ☐
Unplugged well with intact wellhead, 2 7/8" tubing, rods hanging in well, pumping unit American 160.

06505592 KELLY OIL AND GAS LLC SMITH M #3 Twp: 10 N Rge: 30 E Sec: 12 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Bond forfeited by Board Order 2-2016. Pending Grant Application ☐
Unplugged ell with intact wellhead, 2 7/8" tubing, rods hanging in well, used tubing laying on location.

07305312 B J OIL POWER 1-A Twp: 27 N Rge: 4 W Sec: 2 SW SW NE Funding Approved ☐

Required: Surface Restoration Performed: Well Status: 1 Well Location: 2 **Ranking: 3** DMA Candidate ☐

Comments: Located in farmed field, pump unit base remains Pending Grant Application ☐

08521256 NATIVE AMERICAN ENERGY GROUP, INC. COX 7-1 Twp: 29 N Rge: 50 E Sec: 7 NE NE Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: Native American Energy Group, Inc. bond forfeited at Board of Oil & Gas "Show Cause" hearing on June 6, 2013 Pending Grant Application ☐
Located in grass land, Pumping unit w/gas motor and shed, propane tank, production string (rods & tubing), treater, recycle pump, 1- 400 bbl fiberglass tank, 2- steel 300 bbl tanks, rig anchors, loose pipe on surface.

10521297 ZIMMERMAN, BRENT HERINGER 11-21 Twp: 30 N Rge: 44 E Sec: 11 NE NW Funding Approved ☐

Required: Plugging and Restoration Performed: Well Status: 2 Well Location: 1 **Ranking: 3** DMA Candidate ☐

Comments: SI oil well, Operator forfeited bond by Order 367-2012, done 2/19/13 Pending Grant Application ☐
pumping unit w/electric motor, wellhead, production string (rods& tubing), rig anchors, treater, recycle pump, propane tank.
5- 400 bbl upright tanks
(old truck, old portable pump, portable tank)

10121897	GENERAL WELL SERVICE INC.	HJARTARSEN 4-8	Twp: 32 N	Rge: 4 W	Sec: 8 SE NW NW		Funding Approved ☐
Required: Surface Restoration	Performed:		Well Status: 1	Well Location: 1	Ranking: 2		DMA Candidate ☐
Comments: 7" surface casing collar at ground level Collar and casing need to be cut off 3' below ground level and capped. Inspected 10/13/09 BH.							Pending Grant Application ☐
10107142	COOLIDGE AND COOLIDGE, INC.	STATE 10-A	Twp: 36 N	Rge: 2 W	Sec: 36 SE NE SW		Funding Approved ☐
Required: Surface Restoration	Performed:		Well Status: 1	Well Location: 1	Ranking: 2		DMA Candidate ☐
Comments: Appears P&A'd - assumed properly. No leaking. Revegetated. Sunk 1 ft where wellhead burried. Site needs 2" pipe pulled out of ground and clean up of old wood, wire ropes, and metal piece/debris. Actual location 1650 FSL and 1650 FWL.							Pending Grant Application ☐
10107714	WESTERN HYDROCARBONS CORP.	STATE 24-36	Twp: 35 N	Rge: 1 E	Sec: 36 SE SW		Funding Approved ☐
Required: Surface Restoration	Performed:		Well Status: 0	Well Location: 2	Ranking: 2		DMA Candidate ☐
Comments: Located in farmed field, well plugged, casing remains above ground level, very little resoration needed.							Pending Grant Application ☐
10521497	COASTAL PETROLEUM COMPANY	STATE 7-16	Twp: 36 N	Rge: 36 E	Sec: 16 SW NE		Funding Approved ☐
Required: Surface Restoration	Performed:		Well Status: 1	Well Location: 1	Ranking: 2		DMA Candidate ☐
Comments: well was plugged 10/18/2012, wellhead cut-off and buried, site has good grass growth, rig anchors remain with junkwood and wire, bond forfeiture money received 12/23/2015.							Pending Grant Application ☐
10110739	TEXAS PACIFIC COAL & OIL CO.	STATE 30	Twp: 35 N	Rge: 2 W	Sec: 36 W2 NE NE		Funding Approved ☐
Required: Surface Restoration	Performed:		Well Status: 0	Well Location: 1	Ranking: 1		DMA Candidate ☐
Comments: Old rod line left on location. Well appears plugged and surface restored.							Pending Grant Application ☐
00906422	OHIO OIL COMPANY	MACK #11 1	Twp: 9 S	Rge: 23 E	Sec: 35 SE SE SE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status:	Well Location:	Ranking:		DMA Candidate ☐
Comments: 7" and 5" csg @ sfc. 5" csg bull plugged. Well completed June 1916, TD 1810'. Completed as an oil well. (Inspeced 6/4/2007)							Pending Grant Application ☐
06521879	UNIONTOWN ENERGY MONTANA LLC	LITTLE MONTANA 1	Twp: 10 N	Rge: 28 E	Sec: 35 SE SE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status:	Well Location:	Ranking:		DMA Candidate ☐
Comments:							Pending Grant Application ☐
10111744	UNKNOWN	WARD XX	Twp: 35 N	Rge: 3 W	Sec: 29 NE SW SE		Funding Approved ☐
Required: Plugging and Restoration	Performed:		Well Status:	Well Location:	Ranking:		DMA Candidate ☐
Comments:							Pending Grant Application ☐

EXHIBIT 5

MONTANA BOARD OF OIL AND GAS CONSERVATION
FINANCIAL STATEMENT
As of 1/25/2017
Fiscal Year 2017: Percent of Year Elapsed - 57%

		Budget	Expends	Remaining	%
Regulatory	Personal Services	1,312,453	555,410	757,043	42.3
UIC	Personal Services	211,630	98,211	113,419	46.4
	Total Expended	**1,524,083**	**653,621**	**870,462**	**42.9**
Regulatory	Equipment & Assets	39,477	-	39,477	0.0
UIC	Equipment & Assets	17,073	-	17,073	0.0
	Total Expended	**56,550**	**-**	**56,550**	**0.0**
Regulatory	Operating Expenses:				
	Contracted Services	175,279	65,054	110,225	37.1
	Supplies & Materials	48,500	18,398	30,102	37.9
	Communication	49,835	20,085	29,750	40.3
	Travel	38,000	10,812	27,188	28.5
	Rent	33,000	14,261	18,739	43.2
	Utilities	20,615	9,418	11,197	45.7
	Repair/Maintenance	21,234	10,761	10,473	50.7
	Other Expenses	25,614	14,714	10,900	57.4
	Total Operating Expenses	412,077	163,504	248,573	39.7
UIC	Operating Expenses:				
	Contracted Services	16,152	8,189	7,963	50.7
	Supplies & Materials	12,561	3,314	9,247	26.4
	Communication	8,350	3,672	4,678	44.0
	Travel	9,213	1,362	7,851	14.8
	Rent	4,175	1,406	2,769	33.7
	Utilities	7,000	1,653	5,347	23.6
	Repair/Maintenance	9,000	2,129	6,871	23.7
	Other Expenses	15,052	1,226	13,826	8.1
	Total Operating Expenses	81,503	22,950	58,553	28.2
	Total Expended	**493,580**	**186,455**	**307,125**	**37.8**

	Budget	Expends	Remaining	%
Carryforward FY15				
Personal Services	40,249	-	40,249	0.0
Operating Expenses	80,497	-	80,497	0.0
Equipment & Assests	80,497	-	80,497	0.0
Total	**201,243**	**-**	**201,243**	**0.0**

Funding Breakout	**Regulatory Budget**	**Regulatory Expends**	**UIC Budget**	**UIC Expends**	**2017 Total Budget**	**2017 Total Expends**	**%**
State Special	1,764,007	718,915	310,206	121,161	2,074,213	840,076	40.5
Federal 2016 UIC (10-1-2015 to 9-30-2016)			108,000	108,000	108,000	108,000	100.0
Federal 2017 UIC (10-1-2016 to 9-30-2017)			105,676	-	105,676	-	0.0
Total	1,764,007	718,915	523,882	229,161	2,287,889	948,076	**41.4**

REVENUE INTO STATE SPECIAL REVENUE ACCOUNT as of 1/25/17

	FY 17	FY 16
Oil & Gas Production Tax	$ 205,281	$ 813,345
Oil Production Tax	186,806	758,083
Gas Production Tax	18,475	55,261
Drilling Permit Fees	7,300	15,025
UIC Permit Fees	96,000	239,600
Interest on Investments	4,741	10,513
Copies of Documents	195	1,407
Public Information Request	221	
Miscellaneous Reimbursements	-	37,500
TOTAL	$ 313,738	$ 1,117,390

REVENUE INTO DAMAGE MITIGATION ACCOUNT as of 1/25/17

	FY 17	FY 16
RIT Investment Earnings:	$ -	$ 490,672
July	-	-
August	-	-
September	-	49,110
October	-	40,670
November	-	37,753
December	-	49,344
January	-	37,052
February	-	37,189
March	-	47,949
April	-	35,271
May	-	36,482
June	-	119,853
Bond Forfeitures:	-	234,904
Interest on Investments	3,104	2,016
TOTAL	$ 3,104	$ 1,218,264

INVESTMENT ACCOUNT BALANCES as of 1/25/17

Regulatory Account	$ 1,027,323
Damage Mitigation Account	$ 1,016,873

REVENUE INTO GENERAL FUND FROM FINES as of 1/25/17

		FY 17
STEALTH ENERGY INC	7/1/16	$ 1,420
ENERGY QUEST II LLC	7/8/16	80
HOFLAND JAMES D	7/8/16	70
MONTANA LAND AND MINERAL COMPANY	7/8/16	60
UNIT PETROLEUM COMPANY	7/8/16	60
VECTA OIL AND GAS LTD	7/8/16	60
TNT OIL LLC	7/15/16	60
STATOIL & GAS LP	8/1/16	420
RINCON OIL AND GAS LLC	8/19/16	70
MONTANA LAND AND EXPLORATION INC	9/2/16	60
WHITING OIL AND GAS CORP	9/9/16	250
GRASSY BUTTE LLC	9/16/16	70
TEMPEL CONTRACTING INC	9/16/16	80
SOLOMON EXPLORATION/SOLOMON, TED/GAIL	9/23/16	60
RANCH OIL CO INC	9/30/16	60
YELLOWSTONE PETROLEUMS INC	10/6/16	50
BRAINSTORM ENERGY INC	10/7/16	60
BRAINSTORM ENERGY INC	10/7/16	60
YELLOWSTONE PETROLEUMS INC	10/7/16	70
MOUNTAIN VIEW ENERGY INC	10/11/16	120
SHADWELL RESOURCES GROUP LLC	10/11/16	1,000
HERCO EXPLORATION LLC	10/14/16	70
COALRIDGE DISPOSAL AND PETROLEUM	10/21/2016	90
JUSTIC SWD LLC	10/21/2016	80
MONTANA OILFIELD ACQUISITION I LLC	10/28/2016	220
BALLANTYNE VENTURES LLC	11/4/2016	90
MCOIL MONTANA ONE LLC	11/9/2016	110
SLOHCIN INC	11/9/2016	70
WIND RIVER HYDROCARBONS	11/9/2016	70
SDOCO LLC	11/18/2016	60
SHADWELL RESOURCES GROUP LLC	11/18/2016	90
SEYMOUR OIL & GAS	**12/5/2016**	**140**
WHITING OIL AND GAS CORP	**12/22/2016**	**250**
BENSUN ENERGY LLC	**1/9/2017**	**120**
MOUNTAINVIEW ENERGY INC	**1/10/2017**	**70**
TOTAL		$ 5,770

GRANT BALANCES - 1/25/17

Name	Authorized Amt*	Expended	Balance	Expiration Date
2011Southern - TankBattery2 RIT 12-8723	$ 204,951	$ 204,951	$ -	9/30/2016
2011 Northern/Eastern RIT 13-8753	332,642	332,642	-	9/30/2016
TOTAL	$ 537,593	$ 537,593	$ -	

* includes match requirement for grant

CONTRACT BALANCES - 1/25/17

Name	Authorized Amt	Expended	Balance	Status	Expiration Date
MT Tech - Elm Coulee EOR Study (MOU 127220)	$ 863,905	$ 575,611	$ 288,294	Under Contract	12/31/2017
Central Avenue Mall FY '16 (9/1/15 - 8/31/16)	400	400	-	Completed	8/31/2016
Central Avenue Mall FY '17 (9/1/16 - 8/31/17)	400	400	-	Completed	8/31/2017
Agency Legal Services 2017	70,000	29,259	40,741	Under Contract	6/30/2017
COR Enterprises - Billings Janitorial	15,188	7,584	7,604	Under Contract	6/30/2017
Kelly #1 Well	19,360	12,744	6,616	Completed	7/31/2016
Big Wall Site	18,451	18,450	-	Completed	9/30/2016
Re-Enter, Re-Plug, and Reclaim Kopp #1 Well	263,930	249,937	13,993	Completed	11/1/2016
Flack #1 Plugging	45,493	2,708	42,785	Under Contract	6/30/2017
O&G Plugging FY 2017 (A)	177,504	62,507	114,997	Under Contract	4/1/2017
TOTAL	$ 1,474,630	$ 959,601	$ 515,029		

Agency Legal Services Expenditures in FY17

Case	Amt Spent
BOGC Duties	$ 15,822
Hekkel	139
CCRC	764
Ostby	-
Interstate	3,486
Malsam	4,981
Hydraulic	4,068
Total	$ 29,259

EXHIBIT 6

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

12/14/2016 Through 2/1/2017

Approved

Butler Petroleum LLC Van Alstyne TX		816 G1		Approved Amount: Purpose:	1/4/2017 $10,000.00 Single Well Bond
Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK			ACT
Tomahawk Oil Company, Inc. Roundup MT		7620 G2		Approved Amount: Purpose:	12/30/2016 $10,000.00 Single Well Bond
Letter of Credit	$10,000.00	1ST SECURITY BANK			ACT
Tomahawk Oil Company, Inc. Roundup MT		7620 G1		Approved Amount: Purpose:	12/30/2016 $10,000.00 Single Well Bond
Letter of Credit	$10,000.00	1ST SECURITY BANK			ACT

Canceled

Black Butte Energy LLC Great Falls MT	757 M1	Canceled Amount: Purpose:	1/19/2017 $50,000.00 Multiple Well Bond
Cenex Harvest States Cooperative Inver Grove Heights MN	735 L1	Canceled Amount: Purpose:	1/24/2017 $25,000.00 Limited Bond
Olsen, R. Todd Lewistown MT	809 G1	Canceled Amount: Purpose:	1/24/2017 $1,500.00 Single Well Bond

Incident Report

EXHIBIT 7

Company	Responsibility	Date	Incident	Oil Released	Water Released	Source	Contained	Latitude	Longitud	County	T-R-S
Bad Water Disposal, LLP	BOG	1/3/2016	Spill or Release		1 Barrels	Tank or Tank Battery	Yes	47.67583	-104.05933	Richland	22N-60E-7 SESE
True Oil LLC	BOG	1/4/2016	Spill or Release	5 Barrels		Flow Line - Injection	Yes	47.69997	-104.22246	Richland	22N-58E-1 SENW
Vanguard Operating, LLC	BOG	1/4/2016	Spill or Release	30 Barrels		Treater	Yes	47.80845	-104.31887	Richland	24N-58E-30 SESE
Slawson Exploration Company Inc	BOG	1/5/2016	Spill or Release	25 Barrels		Well Head	Yes	47.60080	-104.16075	Richland	21N-59E-4 S2SW
Beren Corporation	BOG	1/6/2016	Spill or Release	10 Barrels		Tank or Tank Battery	Yes	48.89783	-112.33396	Glacier	36N-6W-12 NEN
Whiting Oil and Gas Corporation	BOG	1/13/2016	Spill or Release		70 Barrels	Trucking/Transportati	Yes	47.88042	-104.10357	Richland	25N-59E-33 NWN
Denbury Onshore, LLC	FED	1/15/2016	Spill or Release		30 Barrels	Flow Line - Production	No	46.42465	-104.31825	Fallon	8N-59E-26 NWN
Denbury Onshore, LLC	BOG	1/19/2016	Spill or Release	2 Barrels	6 Barrels	Flow Line - Production	No	46.64879	-104.47051	Fallon	10N-58E-6 SENW
Anadarko Minerals, Inc.	BOG	1/22/2016	Spill or Release		100 Barrels	Tank or Tank Battery	Yes	48.40199	-106.09383	Valley	31N-43E-35 SWN
Anadarko Minerals, Inc.	BOG	1/23/2016	Spill or Release	246 Barrels		Tank or Tank Battery	No	48.39135	-105.99121	Valley	30N-44E-3 NENW
Triangle USA Petroleum Corporation	BOG	1/24/2016	Spill or Release	21 Gallons		Treater	No	48.44814	-104.12378	Sheridan	31N-58E-12 SES
Slawson Exploration Company Inc	BOG	1/26/2016	Spill or Release		55 Barrels	Tank or Tank Battery	Yes	47.74773	-104.95982	Richland	23N-53E-18 SESE
Denbury Onshore, LLC	BOG	1/28/2016	Spill or Release		95 Barrels	Tank or Tank Battery	Yes	46.96400	104.77000	Dawson	14N-55E-17 SESE
XTO Energy Inc.	BOG	2/6/2016	Spill or Release	10 Barrels		Flare Pit	No	47.86640	-104.58588	Richland	24N-56E-6 NW
Montana Oil Field Acquisition I, LLC	BOG	2/9/2016	Spill or Release	25 Barrels	100 Barrels	Tank or Tank Battery	No	48.13352	-112.19001	Pondera	28N-5W-36 SESW
Denbury Onshore, LLC	BOG	2/11/2016	Spill or Release		1 Barrels	Flow Line - Production	No	46.33495	-104.13515	Fallon	7N-61E-30 SWNW
Denbury Onshore, LLC	FED	2/12/2016	Spill or Release		20 Barrels	Flow Line - Production	Yes	46.73053	-104.56138	Wibaux	11N-57E-4 SWSW
Statoil Oil & Gas LP	BOG	2/12/2016	Spill or Release	5 Gallons		Flare Pit	No	48.01505	-104.14176	Richland	26N-59E-7 SESE
Denbury Onshore, LLC	BOG	2/17/2016	Spill or Release	2 Barrels		Well Head	Yes	45.13324	-105.06646	Powder River	8S-54E-23 NWNE
Anadarko Minerals, Inc.	BOG	2/17/2016	Spill or Release		50 Barrels	Tank or Tank Battery	Yes	48.35826	-105.87184	Valley	30N-45E-16 NENE
Denbury Onshore, LLC	BOG	2/18/2016	Spill or Release		5209 Barrels	Flow Line - Injection	No	46.62010	-104.45500	Fallon	10N-58E-17 NEN
Denbury Onshore, LLC	BOG	2/20/2016	Spill or Release		200 Barrels	Flow Line - Injection	No	46.72068	-104.52096	Wibaux	11N-57E-10 NESE
Denbury Onshore, LLC	BOG	2/22/2016	Spill or Release	5 Barrels	1 Barrels	Flow Line - Production	No	46.58160	-104.43094	Fallon	10N-58E-33 NEN
Abraxas Petroleum Corporation	BOG	2/23/2016	Spill or Release	10 Barrels		Treater	No	48.63004	-104.46446	Sheridan	33N-55E-12 SEN
Continental Resources Inc	BOG	2/28/2016	Fire			Flare Pit	No	47.93818	-104.67918	Richland	25N-54E-12 NENE
Denbury Onshore, LLC	BOG	2/29/2016	Spill or Release	3 Barrels	7 Barrels	Vessel/Container	Yes	46.39615	-104.25414	Fallon	8N-60E-32 SESW
Bayswater Exploration & Production, LLC	BOG	3/10/2016	Spill or Release		150 Barrels	Flow Line - Production	Yes	46.61965	-108.37834	Musselshell	10N-27E-19 NEN
Yellowstone Petroleums, Inc.	BOG	3/19/2016	Spill or Release	20 Barrels	100 Barrels	Tank or Tank Battery	No	48.75364	-112.02185	Toole	35N-3W-32 NWN
Montana Oil Field Acquisition I, LLC	BOG	3/28/2016	Fire	50 Barrels		Tank or Tank Battery	Yes	48.12988	-112.18730	Teton	27N-5W-1 NWNE
Denbury Onshore, LLC	BOG	4/8/2016	Spill or Release		100 Barrels	Flow Line - Injection	No	46.44315	-104.28404	Fallon	8N-59E-13 SE
Slawson Exploration Company Inc	BOG	4/11/2016	Spill or Release	70 Barrels		Tank or Tank Battery	No	47.83445	-104.87855	Richland	24N-53E-14 SWS
Denbury Onshore, LLC	BOG	4/12/2016	Spill or Release	5 Barrels	3 Barrels	Flow Line - Production	No	46.55239	-104.39942	Fallon	9N-58E-10 NENE
True Oil LLC	BOG	4/13/2016	Fire		1 Barrels	Tank or Tank Battery	Yes	47.95245	-104.22585	Richland	25N-58E-4 NENE
Petro-Hunt, LLC	BOG	4/15/2016	Spill or Release		48 Barrels	Tank or Tank Battery	Yes	47.71549	-104.48523	Richland	23N-56E-36 NWN
Vanguard Operating, LLC	BOG	4/15/2016	Fire			Treater	Yes	47.69387	-104.14448	Richland	22N-59E-4 NESE
Poor Boy Oil, LLP	BOG	4/20/2016	Spill or Release	1 Barrels	30 Barrels	Tank or Tank Battery	No	47.81771	-104.18282	Richland	24N-59E-29 NWN
Foundation Energy Management, LLC	BOG	4/23/2016	Spill or Release		100 Barrels	Well Head	Yes	48.29975	-104.51691	Roosevelt	29N-55E-1 NWN
Continental Resources Inc	BOG	5/2/2016	Fire			Flare Pit	Yes	47.89731	-104.41079	Richland	25N-57E-19 SES
Montana Oil Field Acquisition I, LLC	BOG	5/25/2016	Spill or Release	25 Barrels	100 Barrels	Tank or Tank Battery	No	48.81327	-111.96281	Toole	35N-3W-2 SESW
Somont Oil Company, Inc.	BOG	5/26/2016	Spill or Release	10 Barrels		Well Head	Yes	48.73232	-111.81937	Toole	34N-2W-2 NESE
Legacy Reserves Operating LP	BOG	6/2/2016	Fire			Treater	No	48.63085	-104.08340	Sheridan	33N-58E-11 SENE
Denbury Onshore, LLC	BOG	6/9/2016	Spill or Release	21 Gallons	10 Barrels	Flow Line - Production	No	46.62501	-104.45237	Fallon	10N-58E-17 NEN
Denbury Onshore, LLC	BOG	6/9/2016	Fire			Other	No	46.40367	-104.22031	Fallon	8N-60E-33 SENE

Company	Responsibility	Date	Incident	Oil Released	Water Released	Source	Contained	Latitude	Longitud	County	T-R-S
Continental Resources Inc	BOG	6/11/2016	Fire	11 Gallons		Flare Pit	Yes	47.73179	-104.59006	Richland	23N-56E-30 NWN
Denbury Onshore, LLC	BOG	6/12/2016	Spill or Release		180 Barrels	Tank or Tank Battery	Yes	46.58160	-104.43094	Fallon	10N-58E-33 NEN
Slawson Exploration Company Inc	BOG	6/13/2016	Spill or Release	25 Barrels		Well Head	No	47.78180	-104.06409	Richland	23N-60E-6 NWSE
Denbury Onshore, LLC	BOG	6/19/2016	Spill or Release		100 Barrels	Other	No	46.42465	-104.31825	Fallon	8N-59E-26 NWN
Denbury Onshore, LLC	BOG	6/25/2016	Spill or Release		35 Barrels	Well Head	No	45.13645	-105.06646	Powder River	8S-54E-14 SWSE
Black Gold Energy Resource Development	BOG	6/26/2016	Spill or Release		1200 Barrels	Tank or Tank Battery	No	47.74891	-104.65243	Richland	23N-55E-15 SWS
Anadarko Minerals, Inc.	BOG	6/28/2016	Spill or Release		200 Barrels	Tank or Tank Battery	Yes	48.37679	-105.97464	Valley	30N-44E-11 NWN
Denbury Onshore, LLC	FED	7/6/2016	Fire	8 Gallons		Flare Pit	No	46.09157	-104.08413	Fallon	4N-61E-24 SESE
Continental Resources Inc	BOG	7/11/2016	Fire	1 Barrels			No	47.74592	-104.55211	Richland	23N-56E-20 NENE
Continental Resources Inc	BOG	7/11/2016	Fire	1 Barrels		Flare Pit	Yes	47.74592	-104.55211	Richland	23N-56E-20 NENE
XTO Energy Inc.	BOG	7/29/2016	Spill or Release	40 Barrels	20 Barrels	Treater	Yes	47.67806	-104.04793	Richland	22N-60E-8 SESW
MCR, LLC	BOG	8/9/2016	Fire	1 Barrels		Tank or Tank Battery	Yes	48.96136	-111.17490	Liberty	37N-4E-14 NESW
Continental Resources Inc	BOG	8/9/2016	Fire			Flare Pit	No	47.74782	-104.57636	Richland	23N-56E-18 SESE
Continental Resources Inc	BOG	8/18/2016	Fire	21 Gallons		Treater	No	47.74592	-104.55192	Richland	23N-56E-20 NENE
Denbury Onshore, LLC	BOG	8/19/2016	Spill or Release		2 Barrels	Flow Line - Production	No	46.32548	-104.13504	Fallon	7N-61E-30 SWSW
True Oil LLC	BOG	8/23/2016	Fire	10 Barrels		Tank or Tank Battery	No	47.95245	-104.22585	Richland	25N-58E-4 NENE
XTO Energy Inc.	BOG	9/1/2016	Fire			Flare Pit	No	47.71672	-104.42247	Richland	23N-57E-32 NENE
Denbury Onshore, LLC	BOG	9/2/2016	Spill or Release	40 Gallons	1140 Barrels	Flow Line - Injection	No	45.10194	-105.12388	Powder River	8S-54E-32 SWSE
Unknown	OTR	9/13/2016	Orphan Well R				No	48.39474	-112.05487	Toole	31N-3W-31 SWS
SDOCO, LLC	BOG	9/13/2016	Spill or Release	5 Barrels	50 Barrels	Other	No	46.67977	-107.67427	Rosebud	11N-32E-27 SENE
Anadarko Minerals, Inc.	BOG	9/16/2016	Spill or Release	5 Barrels	70 Barrels	Flow Line - Injection	Yes	48.38003	-105.98634	Valley	30N-44E-3 SWSE
Anadarko Minerals, Inc.	BOG	9/16/2016	Spill or Release	5 Barrels	70 Barrels	Flow Line - Injection	Yes	48.38003	-105.98634	Valley	30N-44E-3 SWSE
SM Energy Company	BOG	9/21/2016	Spill or Release		255 Barrels	Tank or Tank Battery	Yes	47.68353	-104.33199	Richland	22N-58E-7 SWNW
Slawson Exploration Company Inc	BOG	9/23/2016	Fire			Treater	No	47.83548	-104.85761	Richland	24N-53E-13 SWS
Denbury Onshore, LLC	FED	9/25/2016	Spill or Release	10 Barrels	65 Barrels	Treater	Yes	46.52728	-104.39411	Fallon	9N-58E-14 SWSW
Bayswater Exploration & Production, LLC	BOG	9/28/2016	Spill or Release		300 Barrels	Flow Line - Injection	No	46.71537	-107.71129	Rosebud	11N-32E-9 SESE
Continental Resources Inc	BOG	9/28/2016	Fire	1 Barrels		Treater	Yes	47.77620	-104.81815	Richland	23N-54E-5 S2S2
Rim Operating, Inc.	BOG	9/29/2016	Spill or Release	5 Barrels		Flow Line - Production	Yes	48.87767	-104.65426	Sheridan	36N-54E-16 SWN
Continental Resources Inc	BOG	10/4/2016	Fire		200 Barrels	Tank or Tank Battery	No	47.80411	-104.65643	Richland	24N-55E-34 NWN
Continental Resources Inc	BOG	10/6/2016	Fire	2 Barrels		Treater	No	47.77620	-104.81815	Richland	23N-54E-5 S2S2
Somont Oil Company, Inc.	BOG	10/6/2016	Spill or Release	200 Barrels		Treater	Yes	48.83512	-111.84455	Toole	36N-2W-34 SENE
Vanguard Operating, LLC	BOG	10/8/2016	Fire	2 Barrels		Treater	Yes	47.61470	-102.24960	Richland	21N-58E-2 NWN
Continental Resources Inc	BOG	10/24/2016	Fire	5 Barrels		Treater	Yes	47.74723	-104.52814	Richland	23N-56E-15 SWS
Anadarko Minerals, Inc.	BOG	10/28/2016	Fire			Treater	No	48.39505	-106.10573	Valley	31N-43E-35 SWS
Continental Resources Inc	BOG	11/3/2016	Fire	5 Gallons		Flare Pit	Yes	47.74738	-104.59451	Richland	23N-55E-13 SESE
Petro-Hunt, LLC	BOG	11/4/2016	Spill or Release	75 Barrels	75 Barrels	Other	No	48.52870	-104.25683	Sheridan	32N-57E-13 SWN
Continental Resources Inc	BOG	11/13/2016	Fire	10 Barrels		Flare Pit	No	47.79098	-104.75324	Richland	24N-54E-35 SWS
Darrah Oil Company, LLC	BOG	11/18/2016	Spill or Release	10 Gallons	20 Barrels	Flow Line - Production	No	48.34766	-105.51991	Roosevelt	30N-48E-18 SESE
Landtech Enterprises, LLC	BOG	12/3/2016	Spill or Release		14 Barrels	Trucking/Transportati	Yes	48.14739	-104.19787	Roosevelt	28N-58E-26 NES
Continental Resources Inc	BOG	12/3/2016	Spill or Release		20 Barrels	Flow Line - Production	No	47.71826	-104.52134	Richland	23N-56E-27 SES
FX Drilling Company, Inc.	FED	12/7/2016	Spill or Release		99 Barrels	Well Head	Yes	48.53151	-112.31031	Glacier	32N-5W-18 NWS
Continental Resources Inc	BOG	12/8/2016	Fire	1 Barrels		Treater	Yes	47.74746	-104.75536	Richland	23N-54E-14 SES
Continental Resources Inc	BOG	12/10/2016	Spill or Release		500 Barrels	Flow Line - Production	No	48.96272	-104.30267	Sheridan	37N-56E-14 SEN
Continental Resources Inc	BOG	12/15/2016	Fire	2 Gallons		Treater	No	47.95532	-104.62522	Richland	26N-55E-33 SES
XTO Energy Inc.	BOG	12/17/2016	Spill or Release	3 Barrels	220 Barrels	Tank or Tank Battery	Yes	47.80596	-104.40265	Richland	24N-57E-28 SESE

Company	Responsibility	Date	Incident	Oil Released	Water Released	Source	Contained	Latitude	Longitud	County	T-R-S
Anadarko Minerals, Inc.	FED	12/27/2016	Spill or Release	10 Barrels	440 Barrels	Pump Failure	No	48.40199	-106.09383	Valley	31N-43E-35 SWN
Bensun Energy, LLC	BOG	12/29/2016	Spill or Release	40 Barrels		Tank or Tank Battery	Yes	48.84194	-104.89549	Sheridan	36N-52E-27 NWS
TAQA USA, Inc.	BOG	1/4/2017	Spill or Release	80 Barrels		Flow Line - Production	No	48.98073	-104.18007	Sheridan	37N-57E-10 NENE
Whiting Oil and Gas Corporation	BOG	1/4/2017	Spill or Release	10 Barrels		Tank or Tank Battery	Yes	47.95467	-104.25585	Richland	26N-58E-32 SWS
Newfield Production Company	BOG	1/7/2017	Fire		70 Barrels	Tank or Tank Battery	No	47.62214	-104.14110	Richland	22N-59E-34 NWS
True Oil LLC	BOG	1/9/2017	Spill or Release	35 Barrels		Treater	No	47.95394	-104.24045	Richland	25N-58E-4 NENW
Northern Oil Production, Inc.	BOG	1/18/2017	Fire				Yes	48.76938	-104.23923	Sheridan	35N-57E-22 SWS
Citation Oil & Gas Corp.	BOG	1/19/2017	Spill or Release	50 Barrels		Tank or Tank Battery	Yes	48.49539	-109.22854	Blaine	32N-19E-35 NEN

EXHIBIT 8

Docket Summary

2/2/2017 Hearing

39-2016	XTO Energy Inc.	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 23N-59E-28: all, 29: all, 32: all, 33: all (Dige #41X-29DXA). Non-consent penalties requested.	*Order 342-2013: PSU - 23N-59E-28: all, 29: all, 32: all, 33: all* *Order 343-2013: Pooling without penalties* *Related Dockets 37-2016, 38-2016, 39-2016* *Protest letter received: 10/26/16*	Lee, John	Exhibits ☐	Flag ☐	**Protested**
1-2017	Montana Oil Field Acquisition I, LLC	Show cause: why additional penalties should not be imposed for failure to address violations at several of the producing leases and pay the penalty of $34,000, and to file production reports.			Exhibits ☐	Flag ☐	
2-2017	Mountain Pacific General Inc.	Show cause: why it should not immediately increase its plugging and reclamation bond to $250,000 and pay the $1,000 penalty for failure to appear at the December hearing.			Exhibits ☐	Flag ☐	
3-2017	Seymour, James G.	Show cause: why additional penalties should not be imposed for failure to pay the administrative penalty assessed for delinquent reporting and for failure to pay the $1,000 fine assessed for not appearing at the December 15, 2016, public hearing.	*Daughter called - fine should be received Wednesday 2/1/2017*		Exhibits ☐	Flag ☐	
4-2017	Seymour, James & Lorraine	Show cause: why additional penalties should not be imposed for failure to pay the administrative penalty assessed for delinquent reporting and for failure to pay the $1,000 fine assessed for not appearing at the December 15, 2016, public hearing.	*Fine was received in Helena prior to the December hearing; show-cause docket should be dismissed.*		Exhibits ☐	Flag ☐	
5-2017	Bensun Energy, LLC	Show Cause: failure to file production reports.	*Fine paid, all reports but one received.*		Exhibits ☐	Flag ☐	
6-2017	Hinto Energy, LLC	Show Cause: failure to file production reports and pay administrative fees.	*Fine received: 1/30/2017; reports received (?)*		Exhibits ☐	Flag ☐	
7-2017	Kykuit Resources, LLC	Show Cause: failure to pay administrative fees assessed for deliquent reporting.	*No fine received. Called; company should be aware of fine and show-cause hearing.*		Exhibits ☐	Flag ☐	
8-2017	Montana Land & Mineral Co.	Show Cause: failure to file production reports and pay administrative fees.	*Reports and fine received: 1/27/2017*		Exhibits ☐	Flag ☐	**Dismissed**
97-2015	Augusta Exploration, LLC	Show Cause: why its plugging and reclamation bond should not be forfeited for failure to provide a plan and timeline of its Krone-Augusta 31-32 well, API # 25-049-21111, located in Section 32, T18N-R5W, Lewis and Clark County, Montana.			Exhibits ☐	Flag ☐	
49-2016	Storm Cat Energy (USA) Operating Corporation	Show Cause: why it should not provide a plan and timeline for the plugging and abandonment or transfer of its three wells and why additional penalties should not be assessed for failure to pay the outstanding fine of $1,340, and appear at the August 11, 2016 public hearing.			Exhibits ☐	Flag ☐	

EXHIBIT 9

GAS FLARING

February 1, 2017

Company	Wells Flaring over 100	Wells Flaring over 100 w/o Exception	Current Exceptions (over 100)	Exception Requests	Wells over 100 Hooked to Pipeline
Continental	1	1	0	1	1
EOG Resources	0	0	0	0	0
Kraken	0	0	0	0	0
Oasis	0	0	0	0	0
Petro-Hunt	3	0	3	0	0
True	0	0	0	0	0
Whiting	5	1	4	4	0
XTO	1	1	0	0	0
Totals	10	3	7	5	1

Flaring Requests

Summary

There are 10 wells flaring over 100 MCFG per day based on current production numbers.

7 of the 10 wells have approved exceptions due to distance, pipeline capacity issues, or time to connection.

There are 5 exceptions requested at this time.

Continental

Revere 1-31H – API #25-083-22953, 27N-53E-31

1. Flaring 145 MCF/D. Fifth exception request.
2. Completed: 2/2013.
3. Estimated gas reserves: 293 MMCF.
4. Proximity to market: Connected to pipeline
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 8 MCF/D.
7. Justification to flare: Unable to sell due to H2S. Currently uneconomic to treat H2S and insufficient capacity issues at Grasslands Plant. It is estimated that it would cost $2.92/MCF to treat the gas and could then only be sold for $2.75/MCF.

Whiting Oil & Gas

Hunter 21-26-1H – API #25-083-23258, 25N-58E-26

1. Flaring 141 MCF/D. Third exception request.
2. Completed: 11/2014.
3. Estimated gas reserves: 379 MMCF.
4. Proximity to market: 500 ft to pipeline.
5. Estimated gas price at market: ~$2.38/MCF.
6. Flaring alternatives: None.
7. Amount of gas used in lease operations: 2 MCF/D.
8. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Hunter 21-26-3H – API #25-083-23275, 25N-58E-26

1. Flaring 178 MCF/D. Third exception request.
2. Completed: 12/2014.
3. Estimated gas reserves: 455 MMCF.
4. Proximity to market: 500 ft to pipeline.
5. Estimated gas price at market: ~$2.38/MCF.
6. Flaring alternatives: None.
7. Amount of gas used in lease operations: 2 MCF/D.
8. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Malsam 14-18-1H – API #25-083-23263, 24N-60E-18

1. Flaring 155 MCF/D. Third exception request.
2. Completed: 1/2015.
3. Estimated gas reserves: 361 MMCF.
4. Proximity to market: 1,500 ft to pipeline.
5. Estimated gas price at market: ~$2.38/MCF.
6. Estimated cost of marketing the gas: ~$200,000.
7. Flaring alternatives: None.
8. Amount of gas used in lease operations: 2 MCF/D.
9. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Iversen 34-32-4H – API #25-083-23238, 26N-58E-32

1. Flaring 115 MCF/D. Third exception request expired 6/3/15.
2. Completed: 7/2014.
3. Estimated gas reserves: 315 MMCF.
4. Proximity to market: 5280 ft to pipeline.
5. Estimated gas price at market: ~$2.38/MCF.
6. Flaring alternatives: None.
7. Amount of gas used in lease operations: 2 MCF/D.
8. Justification to flare: Insufficient compression capacity on Oneok's system in this area