U.S. BUREAU OF LAND MANAGEMENT
MONTANA / DAKOTAS STATE OFFICE

Appendix F

Hydraulic Fracturing White Paper

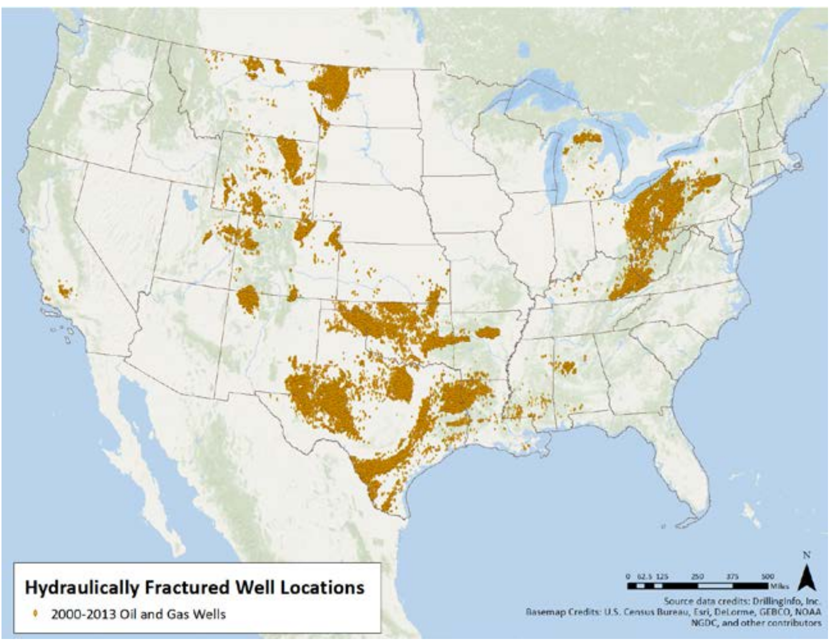
2/28/2019

I. Background

Since the mid-2000s, the combination of modern hydraulic fracturing and directional drilling has significantly contributed to a surge in oil and gas production in the United States. Hydraulic fracturing is widely used in unconventional (low permeability) oil and gas reservoirs that include shales, tight oil and tight gas formations, and in conventional reservoirs.

Using data from several commercial and public sources, the EPA estimates that 25,000 to 30,000 new wells were drilled and hydraulically fractured in the United States annually between 2011 and 2014. These hydraulic fracturing wells are geographically concentrated; in 2011 and 2012 almost half of hydraulic fracturing wells were located in Texas, and a little more than a quarter were located in the four states of Colorado, Pennsylvania, North Dakota, and Oklahoma (USEPA 2016, page 3-1).

Figure 1. Locations of the approximately 275,000 wells drilled and hydraulically fractured between 2000 and 2013. (USEPA, 2016)



Hydraulic fracturing has been utilized by the oil and gas industry since the late 1940s as a standard treatment for stimulating the productivity of oil and gas wells. The process consists of pumping a viscous fluid containing a propping agent into a wellbore at high pressure in order to create and stabilize fractures that extend from the wellbore into the target oil or gas formations.

Generally, HF can be described as follows:

1. Water, proppant, and chemical additives are pumped at high pressures down the wellbore.
2. The fracturing fluid is pumped through perforated sections of the wellbore and into the surrounding formation, creating fractures in the rock. The proppant holds the fractures open during well production.

3. Company personnel continuously monitor and gauge pressures, fluids and proppants, studying how the sand reacts when it hits the perforations of the wellbore, slowly increasing the density of sand to water as the frac progresses.
4. This process may be repeated multiple times, in “stages” to reach maximum areas of the formation(s). The wellbore is temporarily plugged between each stage to maintain the highest fluid pressure possible and get maximum fracturing results in the rock.
5. The plugs are drilled or removed from the wellbore and the well is tested for results.
6. The fracturing fluids are returned up the wellbore for disposal or treatment so they can be re-use, leaving the most of the proppant in place to prop open the fractures and allow the oil/gas to flow.

II. Operational Issues

Wells that undergo hydraulic fracturing may be drilled vertically, horizontally, or directionally and the resultant fractures induced by the hydraulic fracturing can be vertical, horizontal, or both depending on the geology and rock properties.

To create or enlarge fractures, fluid typically comprised of water and additives is pumped into the productive formation at a gradually increasing rate and pressure. Hydraulic fracturing fluid is approximately 98 percent water with the remainder being chemical additives and propping agents (proppant), such as sands or synthetic ceramics. Chemicals used in stimulation fluids include acids, friction reducers, surfactants, gelling agents, scale inhibitors, corrosion inhibitors, antibacterial agents, pH adjusting agents and typically comprise less than 2% of the total fluid.

TABLE 1: FRACTURING FLUIDS AND CONDITIONS FOR THEIR USE:

Base Fluid	***Fluid Type***	***Main Composition***	***Use Conditions***
Water Based	*Linear Fluids*	*Gelled Water, GUAR<HPG, HEC, CMHPG*	*Short Fractures, Low Temperatures*
	Crosslinked Fluids	*Crosslinker + GUAR, HPG, CMHPG, CMHEC*	*Long Fractures, High Temperatures*
Foam Based	*Water-based Foam*	*Water and Foamer + N2 or CO2*	*Low Pressure Formations*
	Acid-based Foam	*Acid and Foamer +N2*	*Low Pressure, Water Sensitive Formations*
	Alcohol-based Foam	*Methanol and Foamer +N2*	*Low Pressure Formations with Water Blocking Problems*
Oil Based	*Linear Fluids*	*Oil, Gelled Oil*	*Water Sensitive Formation, Short Fractures*
	Crosslinked Fluids	*Phosphate Ester Gels*	*Water Sensitive Formation, Long Fractures*
	Water External Emulsions	*Water + Oil + Emulsifier*	*Good for Fluid Loss Control*

Source: EPA 2004.

TABLE 2: FRACTURING FLUID CHEMICAL ADDITIVES

Type of Additive	***Function Performed***	***Typical Products***
Biocide	*Kills Bacteria*	*Gluteridehyde Carbonate*
Breaker	*Reduces Fluid Viscosity*	*Acid, Oxidizer, Enzyme Breaker*
Buffer	*Controls the pH*	*Sodium Bicarbonate, Fumaric Acid*
Clay Stabilizer	*Prevents Clay Swelling*	*KCl, NH CL, KCl Substitutes*
Diverting Agent	*Diverts Flow of Fluid*	*Ball Sealers, Rock Salt, Flake Boric-Acid*
Fluid Loss Additive	*Improves Fluid Efficiency*	*Diesel, Particulates, Fine Sand*
Friction Reducer	*Reduces the Friction*	*Anionic Copolymer*
Gel Stabilizer	*Reduces Thermal Degradation*	*MEOH, Sodium Thiosulphate*
Iron Controller	*Keeps Iron In Solution*	*Acetic & Citric Acid*
Surfactant	*Lowers Surface Tension*	*Fluorocarbon, Nonionic*

Source: EPA 2004.

When the pressure exceeds the rock strength, the fluids create or enlarge fractures that can extend several hundred feet away from the well. As the fractures are created, a propping agent (usually sand) is pumped into the fractures to keep them from closing when the pressure is released. After fracturing is completed, the majority of the injected fluid returns to the wellbore and is reused or disposed of at an approved disposal facility. Proppant, consisting of synthetic ceramics or natural silica sand, may be used in quantities of few hundred tons for a vertical well to a few thousand tons for a horizontal well.

A typical hydraulic fracture stimulation technique involves 1-200 stages. Each stage is a section of the wellbore in the producing formation. This allows for more efficient use of hydraulic fracturing fluid and proppant with a more evenly distributed treatment of the full length of the producing formation. Once all the stages have been completed, the wellbore is cleaned out and put on production. Within the larger BLM Montana-Dakotas planning area, hydraulic fracturing, in conjunction with horizontal drilling, has allowed for development of unconventional zones that were once considered uneconomical, like the Bakken and Three Forks Formations in the Williston Basin area.

Fractures created during hydraulic fracturing enable better flow of oil and gas from the reservoir into the production well. Water that naturally occurs in the oil and gas reservoirs also typically flows into and through the production well to the surface as a byproduct of the oil and gas production process.

In general, approximately 50,000 to 300,000 gallons may be used to fracture shallow coalbed methane wells. In the Bakken oil play, approximately 5 million gallons may be used to fracture a horizontal well.

Proppant, consisting of synthetic ceramic or natural silica sand, may be used in quantities of a few hundred tons for a vertical well to a few thousand tons for a horizontal well.

Water, proppant and hydraulic fracturing fluids are stored in onsite tanks during the drilling and/or completion process. Equipment transport and setup can take several days, and the actual HF and flowback process can occur in a few days or up to a few weeks. For oil and gas wells, the flowback fluid from the HF operations is treated in a multi-phase separator where the oil and water are piped to oil and water tanks and the gas is diverted to flare for safety reasons. In some cases all three phases are piped directly to a production unit on location so the oil and gas can be sold during the flowback operations.

Gas emissions

HF flowback may be captured when the gas at the surface is in marketable condition and the onsite production facilities are capable of processing the gas. When the gas flowed back to surface is not in a marketable condition, or the onsite production facilities are not ready to process the gas, the gas will be flared in accordance with federal and state regulations. The total volume of emissions from the equipment used (trucks, engines, fluid pumps) will vary based on the pressures needed to fracture the well, and the number of zones to be fractured. Emissions associated with a project, and HF if proposed, will be analyzed through a site specific NEPA document to ensure that the operation will not cause a violation of the Clean Air Act.

Fracturing Fluids

Oil and gas operators must maintain water resource integrity through operations that prevent or minimize adverse effects to surface and subsurface resources, minimize surface disturbance, and conform with currently available technology, industry standards and regulations. Oil and gas operators cannot commence either drilling operations or preliminary construction activities before the BLM's approval of the Application for Permit to Drill (APD). A copy of the approved APD and any Conditions of Approval must be available for review at the drill site and all operators, contractors, and subcontractors must comply with the requirements of the approved APD and/or Surface Use Plan of Operations. Unless it is otherwise provided in an approved Surface Use Plan of Operations, the operator must not conduct operations in riparian areas, floodplains, playas, lakeshores, wetlands, and/or areas subject to severe erosion and mass soil movement.

The amount of water needed to hydraulic fracture a well depends on the geologic basin, the thickness and type of formation, and the proposed completion process. Vertical completions typically require much less hydraulic fracturing fluids than horizontal completions. For example, in a vertical completion the wellbore may penetrate 30 feet of the formation but in a horizontal completion the wellbore may penetrate three miles (15,840 feet) of the formation. A vertical completion may be hydraulically fractured in one stage and horizontal completion in up to 200 stages.

Across the United States, the median volume of water used, per well, for hydraulic fracturing was approximately 1.5 million gallons between January 2011 and February 2013. Table 3 below identifies median volumes, and the 10th and 90th percentiles for water use per hydraulically fractured well between January 2011 and February 2013 for 15 states including North Dakota (USEPA 2016a). North Dakota's median volume per well (2,022,380 gallons or 48,152 barrels) is less than the national median volume. While hydraulic fracturing uses billions of gallons of water every year at the national and state scales, when expressed relative to total water use or consumption, however, hydraulic fracturing generally accounts for only a small percentage, usually less than 1%. (USEPA, 2016, page 4-46).

TABLE 3: WATER USE PER HYDRAULICALLY FRACTURED WELL BETWEEN JANUARY 2011 AND FEBRUARY 2013.

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

State	Number of FracFocus 1.0 Disclosures	Median Volume per Well (gallons)	10th percentile (gallons)	90th percentile (gallons)
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

Medians and percentiles were calculated from data submitted to FracFocus 1.0 (Appendix B). USEPA, 2016a

Re-Fracturing

Re-fracturing of wells (RF) may be performed after a period of time to restore declining production rates. RF success can be attributed to enlarging and reorienting existing fractures while restoring conductivity due to proppant degradation and fines plugging.

Waste Water Disposal

Under either completion process, wastewaters from HF may be disposed in several ways. For example, the flowback fluids may be stored in tanks pending reuse; the resultant waste may be re-injected using a permitted injection well, or the waste may be hauled to a licensed facility for treatment, disposal and/or reuse.

The EPA and various State agencies regulate the disposal of wastes generated by the development and production of oil and gas. Underground waste disposal is regulated under the Underground Injection Control (UIC) program, which is authorized under the Safe Drinking Water Act (SDWA). The Resource Conservation and Recovery Act (RCRA) conditionally exempted wastes associated with exploration, development, and production of oil and gas from regulation as a hazardous waste. Exempted wastes include well completion, treatment and stimulation fluids, workover wastes, packing fluids, and constituents removed from produced water before disposal.

Disposal of the waste must be handled in accordance with Onshore Order No. 7 and other state/federal rules and regulations. According to Onshore Order No. 7:

> This Order is established pursuant to the authority granted to the Secretary of the Interior by various Federal of Indian and statutes and the Federal Oil and Gas Royalty Management Act of 1982. Said authority has been delegated to the Bureau of Land Management and is implemented by the onshore oil and gas operating regulations contained in 43 CFR part 3160. Section 3164.1 thereof specifically authorizes the Director to issues Onshore Oil and Gas Orders when necessary to implement or supplement the operating regulations and provides that all such Order shall be

binding on the operators of Federal and restricted Indian oil and gas leases which have been, or may hereafter, be issued. As directed by the Federal Onshore Oil and Gas Leasing Reform Act of 1987, for National Forest lands the Secretary of Agriculture shall regulate all surface-disturbing activities and shall determine reclamation and other in the interest of conservation of surface resource. Specific authority for the provisions contained in this Order is found at section 3162.3, Conduct of Operations; section 3162.5, Environment and Safety; and Subpart 3163, Noncompliance and Assessments.

Potential Sources of Water for Hydraulic Fracturing

The decision to use any specific source is dependent on BLM authorization at the APD stage. BLM must also consult with the U.S Fish and Wildlife Service in accordance with the Endangered Species Act (ESA) as amended (16 U.S .C. 1531 et seq.). Where this is an issue, the USFWS would be consulted during the preparation of the appropriate Resource Management Plan (RMP) and would again be consulted on a case-by-case basis. From an operators' standpoint, the decision regarding which water source will be used is primarily driven by the economics associated with procuring a specific water source.

The three major sources of water for hydraulic fracturing are surface water (i.e., rivers, streams, lakes, and reservoirs), groundwater, and reused hydraulic fracturing wastewater. Potential water sources available for hydraulic fracturing and drilling operations in Montana and North Dakota vary considerably in space and time, but may include irrigation water that is leased or purchased, water purchased from a water provider such as municipalities, treated wastewater, new surface water diversions, produced water, reused or recycled drilling water, or on-location water supply wells. During the chemical mixing stage of the hydraulic fracturing, chemicals are added to water to alter its properties for hydraulic fracturing, some of which are known to be hazardous to human health. The severity of impacts on fresh water resources depends, in part, on the identity and amount of chemicals that enter the environment, which can vary from well to well, and from site-specific characteristics. Operators must comply with North Dakota and Montana water law and secure necessary water rights from the Montana Department of Natural Resources and Conservation or the North Dakota State Water Commission.

III. Potential Impacts to Usable Water Zones

Impacts to freshwater supplies can originate from point sources, such as chemical spills, chemical storage tanks (aboveground and underground), industrial sites, landfills, household septic tanks, and mining activities. Impacts to usable waters may also occur through a variety of oil and gas operational sources which may include, but are not limited to, pipeline and well casing failure, and well (gas, oil and/or water) drilling and construction of related facilities. Similarly, improper construction and management of open fluids pits and production facilities could degrade ground water quality through leakage and leaching.

Usable groundwater aquifers are most susceptible to pollution where the aquifer is shallow (within 100 feet of the surface depending on surface geology), perched, very permeable, or connected directly to a surface water system. Susceptible areas may include floodplains and/or alluvial valleys, or where operations occur in highly fractured geologic formations, and/or lack a sealing formation between the production zone and the usable water zones. If an impact to usable waters were to occur, a greater number of people could be affected in densely populated areas versus sparsely populated areas characteristic of Montana and North Dakota.

Potential impacts on usable groundwater resources from fluid mineral extraction activities can result from the five following scenarios:

1. Contamination of aquifers through the introduction of drilling and/or completion fluids through spills or drilling problems such as lost circulation zones.
2. Communication of the induced hydraulic fractures with existing fractures potentially allowing frac fluid migration into usable water zones/supplies. The potential for this impact is likely dependent on the local hydraulic gradients where those fluids are dissolved in the water column.
3. Cross-contamination of aquifers/formations that may result when fluids from a deeper aquifer/formation migrate into a shallower aquifer/formation due to improperly cemented well casings.
4. Localized depletion of unconfined groundwater availability.
5. Progressive contamination of deep confined, shallow confined, and unconfined aquifers if the deep confined aquifers are not completely cased off, and geologically isolated, from other units. An example of this would be salt water intrusion resulting from sustained drawdown associated with the pumping of groundwater.

Casing and cementing.

The impacts above could occur as a result of improper casing and cementing practices. Freshwater-quality water is required to drill the surface-casing section of the wellbore per federal regulations; other sections of the wellbore (intermediate and/or production strings) would be drilled with appropriate quality makeup water as necessary. This is done to protect usable water zones from contamination, to prevent mixing of zones containing different water quality/use classifications, and to minimize total freshwater volumes. With detailed geologic well logging during drilling operations, geologists/mud loggers on location identify the bottoms of these usable water zones, which aids in the proper setting of casing depths.

Authorization of proposed projects would require full compliance with local, state, and federal directives and stipulations that relate to surface and groundwater protection, and the BLM would deny any APD that proposes drilling and/or completion processes that are insufficient to protect of usable water, as required by 43 CFR 3162.5-2(d). Any proposed drilling/completion activities would have to comply with Onshore Order No. 2, 43 CFR 3160 regulations, and not result in a violation of a Federal and/or State laws that prohibit degradation of surface or groundwater quality.

To ensure that drilling and completion operations are conducted in a safe and environmentally sound manner, the BLM approves and regulates all drilling operations and related surface disturbance associated with Federal and Indian oil and gas mineral development. Operators must submit an Application for a Permit to Drill (APD) to the agency in accordance with Onshore Oil and Gas Order No.1. Prior to approving an APD, the BLM identifies all potential subsurface formations that will be penetrated by the wellbore. This includes groundwater aquifers and any zones that would present potential safety or health risks that may need special protection measures during drilling, or that may require specific protective well construction measures. All well casing and cementing operations that occur on Federal/Indian lands would be reviewed and approved by BLM and conducted in accordance with the applicable requirements specified in Onshore Oil and Gas Order No. 2, and American Petroleum Institute (API) standards

At the APD approval stage, the Petroleum Engineer (PE) in the Field Office (FO) reviews all proposed casing and cement designs to ensure public safety and the protection of usable water in accordance with Onshore Order No. 2.

> Determination of casing setting depth shall be based on all relevant factors, including: presence/absence of hydrocarbons; fracture gradients; usable water zones; formation pressures; lost circulation zones; other minerals; or other unusual characteristics. All indications of usable water shall be reported.

More specifically in accordance with Onshore Order No. 2 III B.1.c;

> The surface casing shall be cemented back to surface either during the primary cement job or by remedial cementing.

The FO Petroleum Engineering Technicians (PETs) do drilling inspections on high priory wells (e.g., near water bodies, new rig in the area, known geological hazards, known problem area, new development, etc.) to witness cementing and pressure testing of casing. If there are any casing or cementing issues during the inspection, the PETs will stop the job until the issue is corrected.

In Federal Fiscal Years 2017 and 2018, there were 20 wells drilled in federal mineral estate associated with the Miles City Field Office and North Central Montana District (19 in Miles City Field Office and one in the North Central Montana District). Drilling inspections were completed for 15 of those wells. Three of the four wells that were not inspected were in a known producing unit with little to no associated risk.

In addition to federal regulations, the Montana Bureau of Oil and Gas Conservation (MBOGC), and North Dakota Department of Health (NDDH) have regulations to protect surface and groundwater. For example, the MBOGC and NDDH regulations require new and existing wells, which will be stimulated by hydraulic fracturing, to demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed. If the operator proposes hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. The cemented well is pressure tested to ensure there are no leaks and a cement bond log is run to ensure the cement has bonded to the casing and the formation. In accordance with MBOGC Rule 36.22.1015, operators are required to disclose and report the amount and type of fluids used in well stimulation to the Board or, if approved by the Board, to the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing web site FracFocus.org. In accordance with North Dakota, Rule 43-02-05-06, all injection wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water or into an unauthorized zone. The casing and cement used in construction of each new injection well shall be designed for the life expectancy of the well.

A well casing design that is not set at the proper depths or a cementing program that does not properly isolate necessary formations could allow oil, gas or HF fluids to contaminate other aquifers/formations.

Natural fractures, faults, and abandoned wells

If HF of oil and gas wells result in new fractures connecting with established natural fractures, or faults, a pathway for gas or contaminants to migrate underground may be created posing a risk to water quality. The potential for this impact is currently unknown but it is generally accepted that the potential decreases with increasing distance between the production zone and usable water zones. This potential again is dependent upon the site specific conditions at the well location due to difference in geology.

The pathways can also occur due to improperly plugged dry or abandoned wells. All Federal and Indian wells will be plugged and abandoned in accordance with Onshore Order No. 2.III.G, which states the following:

> The following standards apply to the abandonment of newly drilled dry or non- productive wells in accordance with 43 CFR 3162.3-4 and section V of Onshore Oil and Gas Order No. 1. Approval shall be obtained prior to the commencement of abandonment. All formations bearing usable-quality water, oil, gas, or geothermal resources, and/or a prospectively valuable deposit of minerals shall be protected. Approval may be given orally by the authorized officer before abandonment operations are initiated. This oral request and approval shall be followed by a written notice of intent to abandon filed not later than the fifth business day following oral approval.
>
> Failure to obtain approval prior to commencement of abandonment operations shall result in immediate assessment of under 43 CFR 3163.1(b)(3). The hole shall be in static condition at the time any plugs are placed (this does not pertain to plugging lost circulation zones). Within 30 days of completion of abandonment, a subsequent report of a abandonment shall be filed. Plugging design for an abandonment hole shall include the following:

1. Open Hole.
    i. A cement plug shall be placed to extend at least 50 feet below the bottom (except as limited by total depth (TD) or plugged back total depth (PBTD)), to 50 feet above the top of:
        a. Any zone encountered during which contains fluid or gas with a potential to migrate;
        b. Any prospectively valuable deposit of minerals.
    ii. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of the hole, plus an additional 10 percent of slurry for each 1,000 feet of depth.
    iii. No plug, except the surface plug, shall be less than 25 sacks without receiving specific approval from the authorized officer.
    iv. Extremely thick sections of single formation may be secured by placing 100-foot plugs across the top and bottom of the formation, and in accordance with item ii hereof. v. In the absence of productive zones or prospectively valuable deposits of minerals which otherwise require placemnt of cement plugs, long sections of open hole shall be plugged at least every 3,000 feet. Such plugs shall be placed across in-gauge sections of the hole, unless otherwise approved by the authorized officer.

2. Cased Hole. A cement plug shall be placed opposite all open perforation and extend to a minimum of 50 feet below (except as limited by TD or PBTD) to 50 feet above the perforated

interval. All cement plugs, except the surface plug, shall have sufficient slurry volume to fill 100 feet of hole, plus an additional 10 percent of slurry for each 1,000 feet of depth. In lieu of the cement plug, a bridge plug is acceptable, provided:

i. The bridge plug is set within 50 feet to 100 feet above the open perforations;
ii. The perforations are isolated from any open hole below; and
iii. The bridge plug is capped with 50 feet of coment. If a bailer is used to cap this plug, 35 feet of cement shall be sufficient.

3. Casing Removed from Hole. If any casing is cut and recovered, a cement plug shall be placed to extend at least 50 feet above and below the stub. The exposed hole resulting from the casing removal shall be secured as required in items 1i and 1ii hereof.

4. An additional cement plug placed to extend a minimum of 50 feet above and below the shoe of the surface casing for intermediate string, as appropriate).

5. Annular Space. No annular space that extends to the surface shall be left open to the drilled hole below. If this condition exists, a minimum of the top 50 feet of annulus shall be plugged with cement.

6. Isolating Medium. Any cement plug which is the only isolating medium for a usable water interval or a zone containg a prspectively valuable deposit of minerals shall be testedby tagging with the drill string. Any plugs placed where the fluid level will not remain static also shall be tested by either tagging the plug with the working pipe string, or pressuring to a minimum pump (surface) pressure of 1,000 psi, with no more than a 10 percent drop during a 15-minute period (cased hole only). If the integrity of any other plug is questionable, or if the authorized officer has specific concerns for which he/she orders a plug to be tested, it shall be tested in the same manner.

7. Silica Sand or Silica Flour. Silica sand or silica flour shall be added to cement exposed to bottom hole static temperatures above 230 øF to prevent heat degradation of the cement.

8. Surface Plug. A cement plug of at least 50 feet shall be placed across all annuluses. The top of this plug shall be placed as near the eventual casing cutoff point as possible.

9. Mud. Each of the intervals between plugs shall be filled with mud of suffcient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. In the absense of other information at the time plugging is approved, a minimum mud weight of 9 pounds per gallon shall be specified.

10. Surface Cap. All casing shall be cut-off at the base of the cellar or 3 feet below final restored ground level (whichever is deeper). The well bore shall then be covered with a metal plate at least 1/4 inch thick and welded in place, or a 4-inch pipe, 10-feet in length, 4 feet above ground and embedded in cement as specified by the authorized officer. The well location and identity shall be permanently inscribed. A weep hole shall be left if a metal plate is welded in place.

11. The cellar shall be filled with suitable material as specified by the authoriz d officer and the surface restored in accordancxe with the instructions of the authorized officer.

Fracture growth

A number of studies and publications report that the risk of induced fractures extending out of the target formation into an aquifer—allowing hydrocarbons or other fluids to contaminate the aquifer—may depend, in part, on the formation thickness separating the targeted fractured formation and the aquifer. Fractures created during HF have not been shown to span the distance between the targeted formation and freshwater bearing zones. If a parcel is sold and development is proposed in usable water zones, those operations would have to comply with federal and/or state water quality standards. Ensuring the safety of drinking water (both surface and groundwater sources) is of paramount importance. In accordance with the Safe Drinking Water Act, the Montana Department of Environmental Quality and North Dakota Department of Health have assessed source water protection areas to protect public water supplies as a part of their Source Water Assessment Programs. The Resource Management Plans (RMPs) for HiLine District, and Billings, Miles City, and South Dakota Field offices all stipulate no surface occupancy in source water protection areas. The Butte RMP stipulates no surface occupancy in four identified municipal watersheds. In a proposed lease sale, the BLM would identify source water protection areas that occur in a given area and apply the appropriate stipulations to conserve resource values.

Fracture growth and the potential for upward fluid migration, through other geologic formations depend on site-specific factors such as the following:

1. Physical properties, types, thicknesses, and depths of the targeted formation as well as those of the surrounding geologic formations.
2. Presence of existing natural fracture systems and their orientation in the target formation and surrounding formations.
3. Amount and distribution of stress (i.e., in-situ stress), and the stress contrasts between the targeted formation and the surrounding formations.
4. Hydraulic fracture stimulation designs include the volume of fracturing fluid injected into the formation as well as the fluid injection rate and fluid viscosity; this information would be evaluated against the above site specific considerations.

Fluid leak and recovery (flowback) of HF fluids

HF Fluids can remain in the subsurface unrecovered, due to “leak off” into connected fractures and the pores of rocks. Fracturing fluids injected into the primary hydraulically induced fracture can intersect and flow (leak off) into preexisting smaller natural fractures. Some of the fluids lost in this way may occur very close to the well bore after traveling minimal distances in the hydraulically induced fracture before being diverted into other fractures and pores. Once “mixed” with the native water, local and regional vertical and horizontal gradients may influence where and if these fluids will come in contact with usable water zones, assuming that there is inadequate recovery either through the initial flowback or over the productive life of the well. Faults, folds, joints, etc., could also alter localized flow patterns as discussed below.

The following processes can influence effective recovery of the fracture fluids:

Check-Valve Effect. A check-valve effect occurs when natural and/ or newly created fractures open and HF fluid is forced into the fractures when fracturing pressures are high, but the fluids are subsequently prevented from flowing back toward the wellbore as the fractures close when the fracturing pressure is decreased (Warpinski et al., 1988; Palmer et al., 1991a). A long fracture can be pinched-off at some distance from the wellbore. This reduces the effective fracture length. HF fluids trapped beyond the "pinch point" are unlikely to be recovered during flowback and oil/gas is unlikely to be recovered during production.

In most cases, when the fracturing pressure is reduced, the fracture closes in response to natural subsurface compressive stresses. Because the primary purpose of hydraulic fracturing is to increase the effective permeability of the target formation and connect new or widened fractures to the wellbore, a closed fracture is of little use. Therefore, a component of HF is to "prop" the fracture open, so that the enhanced permeability from the pressure-induced fracturing persists even after fracturing pressure is terminated. To this end, operators use a system of fluids and "proppants" to create and preserve a high-permeability fracture-channel from the wellbore deep into the formation.

The check-valve effect takes place in locations beyond the zone where proppants have been placed (or in smaller secondary fractures that have not received any proppant). It is possible that some volume of stimulation fluid cannot be recovered due to its movement into zones that were not completely "propped" open.

Adsorption and chemical reaction. Adsorption and chemical reactions can also prevent HF fluids from being recovered. Adsorption is the process by which fluid constituents adhere to a solid surface and are thereby unavailable to flow with groundwater. Adsorption to coal is likely; however, adsorption to other geologic material (e.g., shale, sandstone) is likely to be minimal. Another possible reaction affecting the recovery of fracturing fluid constituents is the neutralization of acids (in the fracturing fluids) by carbonates in the subsurface.

Fracturing fluids injected into the target zone flow into fractures under very high pressure. The hydraulic gradients driving fluid flow away from the wellbore during injection are much greater than the hydraulic gradients pulling fluid flow back toward the wellbore during flowback and production (pumping) of the well. Some portion of the fracturing fluids could be forced along the hydraulically induced fracture to a point beyond the capture zone of the production well. The size of the capture zone will be affected by the regional groundwater gradients, and by the drawdown caused by producing the well. Site-specific geologic, hydrogeologic, injection pressure, and production pumping details should provide the information needed to estimate the dimension of the production well capture zone and the extent to which the fracturing fluids might disperse and dilute.

IV. Geologic Hazards

Potential geologic hazards caused by HF include induced seismic activity. Induced seismic activity could indirectly cause surficial landslide activity where soils/slopes are susceptible to failure.

Landslides involve the mass movement of earth materials down slopes and can include debris flows, soil creep, and slumping of large blocks of material.

Earthquakes occur when energy is released due to blocks of the earth's crust moving along areas of weakness or faults. Earthquakes attributable to human activities are called induced seismic events or induced earthquakes. In the past several years induced seismic events related to energy development projects have drawn heightened public attention. Although only a very small fraction of injection and extraction activities at hundreds of thousands of energy development sites in the United States have induced seismic activity at levels that are noticeable to the public, seismic events caused by or likely related to energy development have been measured and felt in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas. These episodes have been linked with the underground storage of drilling and HF waste water.

According to the North Dakota Department of Mineral Resources oil and gas division:

> North Dakota geology is very suitable for underground injection of oil and gas wastes. Disposal injection in North Dakota is typically one-half mile below the deepest underground source of drinking water (USDW) and one mile to two miles above the granite rock formations where earthquakes originate. However, as a precaution North Dakota has rules in place relative to induced seismicity: North Dakota requires a map depicting the area around the location where the disposal well is proposed that depicts any known or suspected faults. Wells must be constructed in a manner that prevents movement of fluids into USDW's or into unauthorized zones. The North Dakota Industrial Commission (NDIC) may require continuous monitoring up to and including seismic monitors as well as sampling injected fluids and testing of the well. The NDIC can modify or suspend the well permit at any time. In addition the NDIC may order the operator to cease injection of a well should it become noncompliant.
>
> Current science indicates that earthquakes originate from faults in the granite rock formations that are much deeper and older than the sedimentary rocks where disposal injection occurs in North Dakota. Other states may have induced seismic activity due to some instances of fluid injection into very deep formations just above the granite rock formations. The Interstate Oil and Gas Compact Commission (IOGCC) recently concluded a review of the potential for injection induced seismicity associated with Oil and Gas Development. North Dakota did not provide data for the primer, but state regulators participated as technical advisors to the IOGCC working group. Access to this study benefits North Dakota citizens and regulators alike. We encourage North Dakotans to review the IOGCC document and become informed on our states very low risk for seismic activity. Specific examples of how low risk North Dakota geology is, as well as how North Dakota compares to states with known stresses or faults can be found on pages 9 and 107 of the IOGCC study. For state regulators, this document provides valuable insight from other states with known induced seismicity. If a very unlikely event should occur in our state, North Dakota regulators can draw on the experience of others to make informed decisions.

In early 2016 the United States Geological Survey released a one year induced seismicity risk assessment, which detailed six states that are at risk for earthquakes due to deep water injection. North Dakota and Montana are two of the forty-four states determined **<u>to not be</u>** at risk for induced seismic activity. The majority of the seismic induced events related to the underground storage of waste water have been reported in Oklahoma. Oklahoma is more vulnerable to seismic activity due to that states stratigraphy and geology. BLM is unaware of any known seismic activity that has been attributed to the underground storage of waste water in the State of Montana.

V. Spill Response and Reporting

Spill Prevention, Control, and Countermeasure (SPCC) - EPAs rules include requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires that operators of specific facilities prepare, amend, and implement SPCC Plans. The SPCC rule is part of the Oil Pollution Prevention regulation, which also includes the Facility Response Plan (FRP) rule. Originally published in 1973 under the authority of §311 of the Clean Water Act, the Oil Pollution Prevention regulation sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires the operator of these facilities to develop and implement SPCC Plans and establishes procedures, methods, and equipment requirements (Subparts A, B, and C). In 1990, the Oil Pollution Act amended the Clean Water Act to require some oil storage facilities to prepare Facility Response Plans. On July 1, 1994, EPA finalized the revisions that direct facility owners or operators to prepare and submit plans for responding to a worst-case discharge of oil.

In addition to EPA's requirements, operators must provide a plan for managing waste materials, and for the safe containment of hazardous materials, per Onshore Order No. 1 with their APD proposal. All spills and/or undesirable events are managed in accordance with Notice to Lessee (NTL) 3-A. Regulations found at 43 CFR 3162.5-1(c) provide BLM with the necessary regulatory framework for responding to all spills and/or undesirable events related to hydraulic fracturing operations.

VI. Public Health and Safety

The intensity, and likelihood, of potential impacts to public health and safety, and to the quality of usable water aquifers is directly related to proximity of the proposed action to domestic and/or community water supplies (wells, reservoirs, lakes, rivers, etc.) and/or agricultural developments. The potential impacts are also dependent on the extent of the production well's capture zone and well integrity. Standard Lease Notice No.1 specifies that development is generally restricted within a quarter mile of occupied dwellings and within 500 feet of riparian habitats and wetlands, perennial water sources (rivers, springs, water wells, etc.) and/or floodplains. Intensity of impact is likely dependent on the density of development.