

Fact Sheet for Permit ID-2D001-A

Injection Well DJS 2-14

Willow Field, Payette County, Idaho

Class II Disposal Well



Cover Sheet for Proposed Issuance of Underground Injection Control (UIC)
Permit ID-2D001-A

What action does this fact sheet describe?	Snake River Oil and Gas, LLC (SROG) has applied to convert an existing hydrocarbon production well into a Class II Disposal Well. This well is located near New Plymouth, Idaho. In this fact sheet, EPA sets forth the principal facts considered in drafting the proposed permit authorizing this activity.
What is proposed in the permit?	This permit, if issued, will allow SROG to inject fluids between 4,908 and 5,500 feet below ground. These fluids would be generated by the hydrocarbon extraction process.
Will new wells be drilled?	The permittee has proposed to inject waste through an existing well that was drilled as a prospective hydrocarbon production well. This well will be converted into a disposal well.
Is an Aquifer Exemption associated with this permit?	EPA has issued a separate document titled, "Record of Decision: Aquifer Exemption of the Willow Sands." Please review that document for more information.
How are shallow aquifers protected?	The injection zone is separated from surface waters and other subsurface drinking water aquifers by impermeable geological layers. The injection zone is isolated by impermeable faults, which isolates the Aquifer Exemption zone.
What will be injected into the well?	Injected waste will include fluids brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. This permit would not allow injection of hazardous waste as classified by the Resource Conservation and Recovery Act.
How can I comment?	The EPA will accept public comments on the draft permit and proposed Aquifer Exemption by email and during a public hearing. If you would like to make a comment, see the Public Comment section at the end of this document.

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PART I. General Information and Description of Project

Permittee: Snake River Oil and Gas, LLC
117 East Calhoun
P.O. Box 500
Magnolia, Arkansas 71754-0500

Well: DJS 2-14, API number: 11-075-20-023, Payette County, Idaho

Surface Location: NE ¼ of the NW ¼ of Section 14, Township 8N Range 4W

Latitude: 44.03867

Longitude: -116.78333

Background

The U.S. Environmental Protection Agency (EPA) received an Underground Injection Control (UIC) permit application from Snake River Oil and Gas, LLC (SROG) on March 16, 2020. After requesting and receiving additional material, EPA determined on April 28, 2020 that SROG had submitted a complete application. At EPA's request, SROG submitted additional application materials on April 23, 2020; August 21, 2021; January 6, 2021; February 3, 2021; February 24, 2021; April 27, 2021; June 17, 2021; and June 21, 2021.

Project Description

Permit ID-2D001-A, if issued, EPA will authorize SROG to convert an existing hydrocarbon production well named DJS 2-14 into a Class II Disposal well. SROG proposes to inject fluids generated during the hydrocarbon production process at its Willow Field in Payette County, Idaho. The existing hydrocarbon production well proposed to become a UIC well has already been drilled, cemented, and constructed into a portion of the Lower Chalk Hills Formation referred to as the Willow Sands. SROG determined that there are not commercially viable quantities of hydrocarbons present within the injection formation accessible by DJS 2-14. SROG proposes to use this well as a UIC Class II disposal well.

The aquifer within the Willow Sands at this location currently meets the definition of an Underground Source of Drinking Water (USDW) pursuant to the SDWA (40 CFR 144.3). SROG submitted a request to EPA for an Aquifer Exemption (AE) for the portions of the Willow Sands that would be impacted by injection. EPA considers any actions regarding SROG's AE request as a separate agency action. (*See*, EPA's 'Record of Decision: Aquifer Exemption of the Willow Sands').

Regulatory Framework

This Fact Sheet describes conditions established by draft Permit ID-2D001-A and reasons for applying such conditions. UIC permits establish conditions for the operation of injection wells to prevent the endangerment of USDWs. EPA bases UIC permit conditions on the following regulations: Title 40 CFR parts 2, 124, 144, 146 and 147. Under 40 CFR § 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions required by regulations and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document.

Primary enforcement responsibility (primacy) for implementation of the UIC program in Idaho is shared between EPA and the Idaho Department of Water Resources (IDWR) and varies by UIC Well Class. IDWR maintains primacy for of UIC Well Class I, III, IV, and V; though, of these well classes, only Class V injection wells are allowable under current state laws and regulations. EPA directly implements UIC Well Classes II and VI in Idaho. Applicable primacy authority can be found under 40 CFR §147 Subpart N.

This permit will expire upon delegation of primary enforcement responsibility for applicable portions of the UIC Program to an approved state or tribal program unless the primacy agency, with the authority to do so, chooses to adopt and enforce this permit as a tribal or state permit.

PART II. Site-Specific Geologic Considerations

Geologic Setting

The order of geologic intervals at this location in order of increasing depth is: 1) Pierce Gulch /shallow alluvium, 2) the Glenns Ferry Formation, and 3) the Chalk Hills Formation. The Lower Chalk Hills Formation contains the Willow Sands, which is where injection will occur. Table 1, below, provides additional detail. The geologic sequence at the site of the proposed injection well was determined primarily by log analysis. Ordering of this sequence is explained by geologic history at this location. The Western Snake River Basin began rifting and subsiding in middle Miocene time at the same time as the eruption of the Columbia River Basalts. Basalts were extruded, and volcanic ash and marsh sediments were laid down as the basin continued to subside. Fluvial sands and sediment washed into and continued filling the basin. Tuffaceous mudstone and siltstone are the predominant lithologies in the upper portion, while sandstones are most common in the lower part of the formation¹.

Surficial deposits are sand or sand/gravel type and contain an aquifer system that serves as a primary drinking water source for private wells in the Payette River Basin. These formations are named either the Pierce Gulch Formation or shallow alluvium, based on location in the Payette River Valley. The Pierce Gulch Formation exists as the upper-most geologic unit in areas where the surface elevation is at least 2,400 ft. above sea level. It is approximately 250 ft. thick at the location of DJS 2-14. At lower elevations, shallow alluvial deposits are found as the upper-most unit.

The Glenns Ferry Formation and Chalk Hills Formation were formed by the sedimentary processes described above. These formations are deeper and older than surficial deposits. The Glenns Ferry Formation is located directly below surficial deposits and is encountered by well DJS 2-14 between the depth interval 250-2,380 ft. TVD. This formation is an upper member of what is known as the Idaho Group and can be characterized by fluvial and lacustrine deposition throughout the Western Snake River Plain. The Glenns Ferry Formation extends several thousand square miles throughout western Idaho and eastern Oregon and has a thickness of around 2,000 ft. This formation is composed of sands, clays, silts, and inter-bedded gravels. At the site of well DJS 2-14, a relatively thick sand layer is seen at a depth of approximately 1,350 to 1,420 ft. below ground surface within the Glenns Ferry Formation. This relatively thick sand layer has been referred to as the “Turbidite Sands,” and contains water in an abundance and quality to be considered a USDW. Besides this major sand interval, the Glenns Ferry Formation is principally claystone.

The transition between the Glenns Ferry Formation and underlying Chalk Hills Formation occurs at approximately 2,380 ft. TVD, though this interface can be difficult to identify due to similar mudstone/claystone character shared between the two formations. Since the Chalk Hills Formation was

¹ Zeolitic Diagenesis of Tuffs in the Miocene Chalk Hills Formation, Western Snake River Plain, Idaho U.S. GEOLOGICAL SURVEY BULLETIN 1963. <https://pubs.usgs.gov/bul/1963/report.pdf>

formed by the interplay of alluvial and lacustrine depositional processes in an active volcano-tectonic setting, both sedimentary and igneous rock types are found. A section of the Lower Chalk Hills Formation is referred to as the Willow Sands. These sands are interspersed with claystone intervals, each unit numbered for convenience. Lower numbers indicate shallower sands, and claystones are identified by the sand sections between which they are found (e.g., Claystone 2/3 is situated below Sand 2 and above Sand 3). Additional information on the Willow Sands is provided in the following section.

Extensive faulting occurs across the Willow Sands. These faults divide the Willow Sands into discrete “Blocks.” This structure, and its impact on injection, is discussed in Part IV of this document.

Injection and Confining Zones

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone.

All major stratigraphic units encountered by DJS 2-14, including those identified as the primary injection and confining zones, are listed in Table 1, seen on the next page.

Table 1 – Geologic Setting, Injection Zone, and Confining Zones. The numbered Willow Sands and claystones are considered portions of the Lower Chalk Hills Formation. Top and Base depth values determined through wellbore logging in DJS 2-14, listed as TVD. Depths marked with an asterisk (*) were estimated by correlation with nearby wellbores and occur below DJS 2-14. All depths based on core sampling and well log analysis provided by the applicant.

Formation Name or Stratigraphic Unit	Top (ft.)	Base (ft.)	Notes
Pierce Gulch/Shallow Alluvium	0	250	Surficial aquifer commonly used for drinking water supply. Soil, sand, gravel.
Glenns Ferry Formation	250	2,380	Lacustrine claystone, minor, scattered arkosic sandstones. “Turbidite” sand at approximately 1,350 ft. – 1,420 ft. TVD.
Chalk Hills Formation	2,380	4,380	Mudstone, siltstone, sandstone, diatomite, and thin volcanics.
Basalt Sill	4,380	4,490	Igneous intrusion. Density values measured for the basalt sill (4380 ft.-4490 ft. MD) in the DJS 2-14 range from 2.9 to 3.01 g/cm ³ .
Chalk Hills Formation	4,490	4,790	Claystone occurs across this depth interval.
Willow Sand 2	4,790	4,860	Possible hydrocarbon accumulations up-dip in Block E.
Claystone 2/3	4,860	4,908	Upper Confining Zone.
Willow Sand 3	4,908	5,030	Injection Zone. Sands and interbedded claystone intervals. Permeability of sandstone estimated at 300 millidarcies (mD).
Claystone 3/4	5,030	5,050	
Willow Sand 4	5,050	5,120	
Claystone 4/5	5,120	5,170	
Willow Sand 5	5,170	5,340	
Claystone 5/6	5,340	5,380	
Willow Sand 6	5,380	5,500	Lower Confining Zone.
Claystone 6/7	5,500*	5,680*	
Willow Sand 7	5,680*	5,880*	
Claystone 7/8	5,880*	6,070*	

Injection Zone

The Willow Sands 3, 4, 5, and 6 are proposed as the injection zone. This injection zone only applies to where these intervals occur within Block E of the fault block system, further described in Part IV. Sands 3-6 occur continuously within Block E, dipping from northwest to southeast. Sands 3-6 are identified in other wells across the Willow Field, demonstrating lateral continuity. In DJS 2-14, Sand 3 (the top of the injection zone) occurs at 4,908 ft. TVD and the bottom of Sand 6 (the bottom of the injection zone) occurs at 5,500 ft. TVD. Because the Willow Sands Formation dips to the southeast, the injection zone is found at different depths throughout Block E. At the shallowest point within Block E, Sand 3 is found at 4,630 ft. below ground level. This is the shallowest occurrence of the injection zone. At the deepest point within Block E, Sand 6 is found at 6,200 ft. below ground level. Stratigraphic cross-sections identifying the injection zone were provided by SROG in their supplemental permit submittal, "SROG Responses to EPA Questions 1 & 2 of [sic] October 29, 2020 Attachment D."

Sidewall core samples from a portion of the injection zone in DJS 2-14 between depths 5,335 ft. and 5,391 ft. TVD were examined for grain characteristics. The sandstone demonstrated poorly sorted, subangular-subrounded sands including abundant (>20%) quartz, moderate (5-10%) igneous fragments, minor to moderate (1-10%) potassium feldspar and plagioclase, and trace (<1%) argillaceous and metamorphic rock fragments. Based on core analysis, permeability was estimated at approximately 300 mD, and porosity between from 30.8% to 32.0%. Density and neutron logs performed in well DJS 2-14 confirm this high porosity. SROG will confirm reservoir permeability under the terms of this permit during pre-injection well testing. High permeability values indicate a greater ability for water to move through rock, a quality needed for a formation to act as a competent injection zone.

Upper Confining Zone

The upper confining zone is the upper barrier to fluid movement; injected fluids may not migrate above the upper confining zone. SROG identified Claystone 2/3 as the upper confining zone, a 40 ft. thick claystone interval between Sand 2 and Sand 3. The DJS 2-14 wellbore passes through Claystone 2/3 between depths 4,860 ft. to 4,908 ft. TVD. Claystone 2/3 is also encountered by nearby wells within the Willow Field, demonstrating lateral continuity. Permeability estimates made by processed petrophysical logging data of Claystone 2/3 indicate permeabilities to be between 0.0002 and 0.0007 mD. Lab-derived permeability (0.01-.04 mD) and porosity values (between 10.3% to 14.6%) were taken from cores sampled from claystone within the Willow Sands at 4,300 ft. to 4,360 ft. TVD during the drilling of DJS 2-14. True effective permeabilities, or the actual permeabilities of the rock in the subsurface, are likely lower than that measured in lab and greater than that measured by downhole logging estimates (i.e., between 0.01 and 0.0007 mD). Lab-tested samples may exhibit inflated permeabilities due to leaks in the testing apparatus/specimen or subtle damage and deterioration of the specimen itself. Log-determined permeabilities may under-measure permeability by ignoring naturally-occurring

heterogeneities that increase effective permeability (i.e., secondary permeability)². Claystone units at the location of DJS 2-14 exhibit low permeability; this indicates a lower ability for water to move through rock and is a quality needed for a geologic unit to act as a competent confining zone.

Redundant confining zones exist above the upper confining zone. Above Sand 2 is a claystone interval of the Lower Chalk Hills Formation approximately 300 ft. thick, and above the basalt sill is a continuous block of claystone within the Glenns Ferry formation stretching from 4,380 ft. TVD to the bottom of the Turbidite Sands at 1,420 ft. TVD, a section of impermeable claystone nearly 3,000 ft. thick. Open hole logging indicates that these claystone intervals exhibit low-permeability and low porosity.

Lower Confining Zone

The lower confining zone is the lower barrier to fluid movement; injected fluids may not migrate below the lower confining zone. SROG identified Claystone 6/7 as the lower confining zone. It is claystone interval encountered by all wells in the Willow Field drilled deep enough to investigate the interval; in well ML 1-11, approximately 1/2 mile to the northwest, it is 130 ft. thick. In ML 3-10, approximately 1 1/4 miles to the northwest, it is 120 ft. thick. In the Reins #2 well, approximately 3 miles to the east, it is 150 ft. thick. Based on correlation with nearby wellbores, this interval is expected to occur between 5,500 ft. to 5,680 ft. TVD in DJS 2-14. Petrophysical logging in well ML 1-11 estimated the permeability of this zone between .0002 to .0007 mD across the unit.

Underground Sources of Drinking Water

Part C of SDWA instructs state and federal environmental agencies to protect USDWs (40 CFR §144.3). An aquifer does not need to be actively used for it to meet the definition of a USDW. A USDW is an aquifer or a portion of an aquifer that supplies a public water system or contains a sufficient quantity of water to supply a public water system and contains fewer than 10,000 milligrams per liter of total dissolved solids (TDS). An aquifer that would be considered a USDW but has been exempted from such status under 40 CFR §§ 144.7 and 146.4 is no longer considered a USDW. Multiple USDWs exist at the location of well DJS 2-14. All known USDWs at the project location are described in Table 2.

The shallowest aquifer system is called either the Pierce Gulch Aquifer or shallow alluvium. Shallow water-bearing units are broadly accessed for drinking water needs across the Payette River Valley both by private and public water sources. As determined by well logging records for DJS 2-14, this system extends to approximately 250 ft. below ground at the location of the injection well.

Below this upper aquifer-bearing unit exist other USDWs not currently accessed for drinking water needs. Well records maintained by IDWR indicate that there are no known drinking water wells accessing USDWs deeper than the Pierce Gulch/shallow alluvium surficial deposit within one lateral mile of the proposed injection well. Deeper USDWs not currently accessed for drinking water needs

² C.E. Neuzil. How Permeable are clays and shales? U.S. Geologic Survey. Water Resources Research, Vol. 30, No. 2., Pages 145,150. February, 1994.

include the Turbidite Sands aquifer, found between 1,350 and 1,420 ft., and the Willow Sands aquifer within the Lower Chalk Hills Formation, occurring below 4,790 ft. Both intervals hold enough water to supply public water systems, and the water quality found in both intervals meets a standard necessary for classification as a USDW.

A basalt intrusion (i.e., basalt sill) exists within a deeper portion of the Chalk Hills Formation. Geothermal test wells in the Western Snake River Plain penetrating similar basalt intrusions indicates water availability from this formation is expected be limited. It is not known whether fluid production could occur at a rate sufficient to be considered a USDW; therefore, for the purposes of this permit application evaluation, this basalt intrusion is considered a USDW. It is encountered by DJS 2-14 between depths of 4,380 ft. and 4,490 ft.

The Willow Sands contains an aquifer and meets the definition of a USDW. Thirteen water samples taken from the Willow Sands were analyzed for TDS. One of these samples was taken from well DJS 2-14, which contained a TDS level of 1,540 mg/l. The average TDS value from all samples taken across the Willow Field from the Willow Sands was 3,109 mg/l TDS. Removing one sample with an anomalously high TDS value, possibly caused by drill fluid contamination, the average level of TDS within the Willow Sands was found to be 2,036 mg/l. The aquifer present in the Willow Sands meets the definition of USDW in the SDWA because it contains a quantity of water sufficient to supply a public water system and contains fewer than 10,000 mg/l TDS.

The Permit applicant requested that a portion of the aquifer in Willow Sands be exempted from status as a USDW. Pursuant to federal regulations at 40 CFR § 146.4, an aquifer or a portion thereof which meets the criteria for an USDW under §146.3 may be determined under §144.7 to be an “exempted aquifer.” Injection of fluids may occur into an aquifer that is exempted from status as a USDW. (See EPA’s *Record of Decision: Aquifer Exemption of the Willow Sands* for additional information.)

Table 2 – All depth measurements taken as feet True Vertical Depth (TVD) encountered by wellbore DJS 2-14.

Formation/Unit	Top (ft.)	Base (ft.)	TDS (mg/l)	Notes
Pierce Gulch/Shallow alluvium	0	250	<500	Surficial aquifer commonly used for water supply
Glenns Ferry Formation (a.k.a., Turbidite Sands)	1,350	1,420	897	Not currently used for drinking water.
Basalt Sill within the Chalk Hills Formation	4,380	4,490	Unknown	Unknown water availability.
Willow Sands	4,790	5,550+	1,540	<i>SROG has requested an exemption of a portion of this aquifer from status as a USDW.</i>

PART III. Well Conversion (40 CFR § 146.22)

DJS 2-14 is currently plugged and inoperable and must be converted to a UIC Class II disposal well according to an EPA-approved well schematic, provided in Appendix A of the permit. Table 3 shows existing structural elements for DJS 2-14. Construction must meet the proposed well schematic plans unless a minor modification procedure (see §144.41) is requested. Modification of well conversion is allowed under 40 CFR § 144.52(a)(1) provided written approval is obtained from EPA prior to actual modification during the construction period.

Casing and Cementing

Details of the well's casing and cement are provided in this section. DJS 2-14 was originally constructed in September 2014. This well was not directionally drilled. A 14" conductor casing pipe was set and cemented in a 20" hole from 80 ft. Measured Depth (MD) to surface. Within the conductor casing pipe, a 9 5/8" surface casing pipe was set and cemented in a 12 1/4" hole from 1,082' MD to surface. The surface casing pipe was cemented using a top job procedure. A 7" long string (production) casing pipe was set and cemented in an 8 3/4" hole. Well construction details are provided in Table 3:

Table 1 – Well construction details for DJS 2-14. All depth measurements in feet MD.

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft.)	Cemented Interval (ft.)
Conductor	20"	14"	0-80	0-80
Surface Casing	12 1/4"	9 5/8"	0-1,082	0-1,082
Long String Casing	8 3/4"	7"	0-5,500	Unknown
Tubing	8 3/4"	2 7/8"	0-4,860	N/a

The cement job performed on the long string is of unknown quality. As such, EPA is requiring additional well logging prior to receiving approval to inject. During initial cementing of the long string casing, the operator emplaced 152 barrels of cement before circulation was lost and returns were not taken at surface. A cement bond log (CBL) was run across the long string casing October 20, 2014, which indicated adequate bonding from 5,500 ft. MD to a depth of approximately 4,650 ft. MD (Figure 1), intermittent bonding from 4,650 ft. to approximately 2,150 ft. MD, and poor bonding or no bonding above 2,150 ft. MD (Figure 2). A top-job cement operation was performed on the 7" casing on October 21, 2014, as a measure to emplace cement from above the existing top of cement to surface. Because the cementing bonding above 2,150 ft. is of unknown quality, the Permittee is required to assess the cement bond behind the long string casing from 2,000 ft. to the surface by completing a cement bond log. This is to ensure that the injection well does not allow the movement of fluids between USDWs. Adequate cement bonding must exist between all USDWs. If results of this CBL do not demonstrate protection of

USDWs, the Permittee may be required to perform additional conversion/repair work on the well. EPA will use guidance established by EPA Region 8, UIC Program³ to determine if adequate bonding is present between all USDWs.

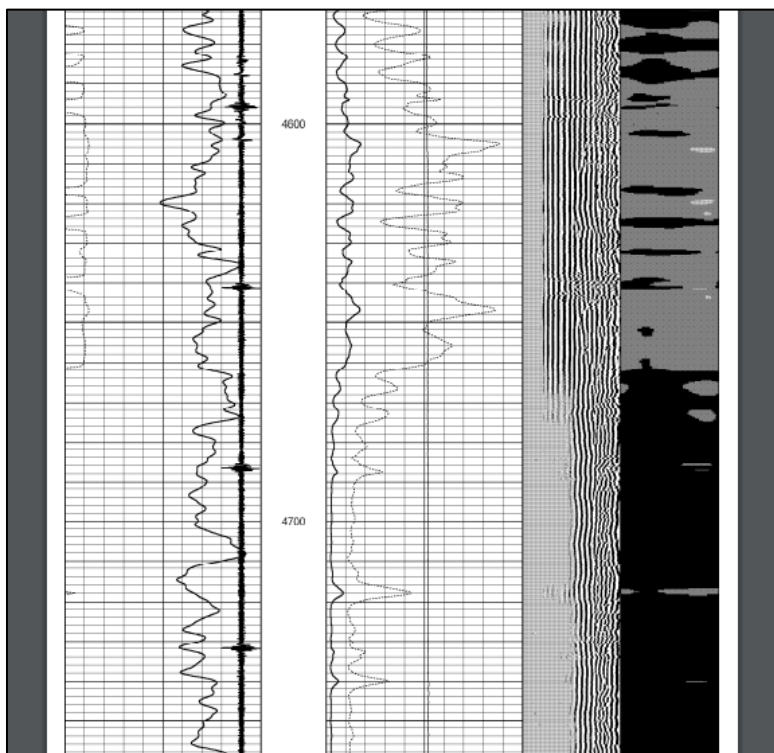


Figure 1 - Cement Bond Log on DJS 2014. Performed October 20, 2014. Track 1 (farthest to left) displays casing collar location/gamma ray. Track 2 is amplitude/amplified amplitude. Track 3 is Variable Density Log. Track 4 is radial sector mapping. Good, consistent cement bonding seen below 4,650 ft.

³ GROUND WATER SECTION GUIDANCE NO. 34: Cement bond logging techniques and interpretation.
<https://www.epa.gov/sites/default/files/2015-08/documents/r8uic-guide34.pdf>

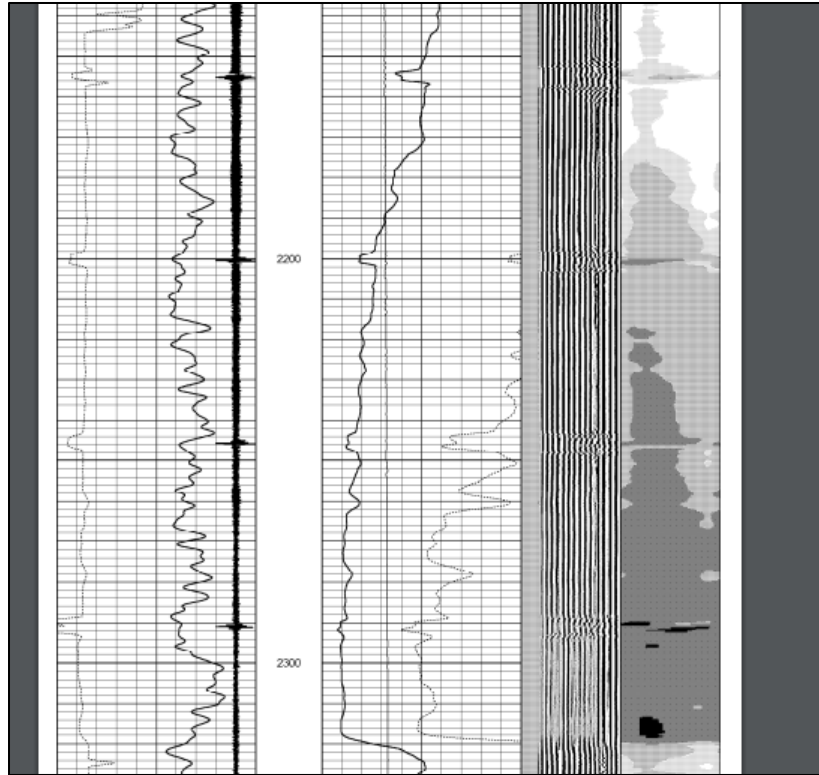


Figure 2 -Cement Bond Log of DJS 2014. Performed October 20, 2014. Track 1 (farthest to left) is casing collar location/gamma ray. Track 2 is amplitude/amplified amplitude. Track 3 is Variable Density Log. Track 4 is radial sector mapping. Intermittent bonding below 2,150 ft. and little/no bonding detected above 2,150 ft.

Injection Tubing, Packer, and Inner Annulus

The Permittee must install injection tubing inside the long string casing from the injection zone to the surface. The Permittee must also install a packer between the tubing and the casing. Tubing and packer are designed to prevent injection fluid from contacting the long string casing above the injection zone.

The Permittee must set the packer no more than 100 ft. above the uppermost perforation in the casing unless the Director⁴ provides written approval for a greater offset distance. The packer must be set at-or-below the depth of the upper confining zone. The Permittee has proposed a packer set depth of 4,860 ft. MD, and upper-most perforations to be created at 4,910 ft. to 4,922 ft. MD. The Director’s decision to allow a greater offset distance from the perforations is based on the depth of the proposed packer, the depth of the upper confining zone, and the depth of USDWs.

The inner annulus is the space between the tubing and the casing, above the packer. The permittee must conduct regular pressure tests of the inner annulus to detect leaks in the casing, tubing, or packer. The permittee must fill the inner annulus with a solution containing appropriate corrosion inhibitors,

⁴ Throughout this document, the term “Director” refers to the Director of the EPA Region 10 Water Division; the Chief or the EPA Region 10 Permitting, Drinking Water and Infrastructure Branch; or an equivalent authority delegated UIC permitting actions.

biocides, and oxygen scavengers as needed to prevent fouling.

The Permittee must isolate existing perforations at 4,306 ft. to 4,330 ft. TVD and 4,354 ft. to 4,374 ft. TVD. This is required to ensure pressure testing of the inner annulus can detect any leaks in tubing/packer assembly.

Sampling and Monitoring Devices

The Permittee must install and maintain sampling and monitoring equipment to collect physical and chemical information representative of the monitored activity. Required equipment includes, but is not limited to: 1) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump before the injection pressure limit is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing, inner annulus, and outer annulus at the wellhead; 3) a fluid sampling station between the pump house or storage tanks and the injection well, isolated by shut-off valves; and 4) two non-resettable flow meters capable of measuring cumulative volume of fluid, one shall be located immediately downstream of the injection pump and the other at the injection wellhead.

PART IV. Area of Review and Additional Considerations

Area of Review (AOR)

Permit applicants are required to identify all wells within the AOR and provide construction details for each well found within the AOR. Title 40 CFR 146.6 requires the establishment of an AOR by one of two methods: calculation of a zone of endangering influence, or by a fixed radius of no less than $\frac{1}{4}$ mile. The Permittee identified an AOR of $\frac{1}{4}$ mile. EPA accepted an AOR of this size due to similarity of injection and formation fluids, hydrogeologic conditions, nearby population, ground water usage of the Willow Sands, and historical practice of Class II permit AOR sizing across the nation.

There are no producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface or subsurface), quarries, residences, roads, drinking water wells or springs within the AOR. The Permittee identified one fault within the AOR. EPA considered the potential for faults near the injection well to pose additional risks to USDWs. See the subsection, “**Fault Confinement**,” below, for more information.

Fault Confinement

This section summarizes EPA’s evaluation of fault properties near DJS 2-14. Faults are of concern to EPA because they can transmit fluids outside of the approved injection zone. Faults can also pose a risk of induced seismicity. This section also discusses why EPA is requiring testing and measurements by SROG as a condition before receiving authorization to inject as assurance that faults will act as barriers to—rather than conduits for—fluid movement. Finally, this section addresses concerns that use of this injection well may result in seismic events felt by humans (i.e., earthquakes).

A fault is a planar fracture within the Earth’s surface typically demonstrating displacement between rock formations on either side. There are numerous small faults throughout the Lower Chalk Hills Formation at Willow Field, one of which is located within the AOR. These faults generally run in the northwest-southeast direction, have greater throw at depth, diminish at the top of the Willow Sands, and die out in the upward direction in the upper Chalk Hills Formation. These faults are relatively short (0.5 – 3 miles) in length. Evidence suggests that these faults occurred during deposition of the Chalk Hills Formation in the middle Pliocene period, and are thus considered “syndepositional,” or “growth” faults⁵. Based on 3-D seismic imaging, the Permittee identified specific faults cross-cutting the field that form vertices at their intersections. Within these faults and their intersections are isolated sections of the Willow Sands, or “Blocks.”

⁵ Swirydczuk, K., *et. al.* 1982. Volcanic ash beds as stratigraphic markers in the Glens Ferry and Chalk Hills Formations from Adrian, Oregon, to Bruneau, Idaho. *Cenozoic Geology of Idaho: Idaho Bureau of Mines and Geology Bulletin* 26, pg. 543-558.

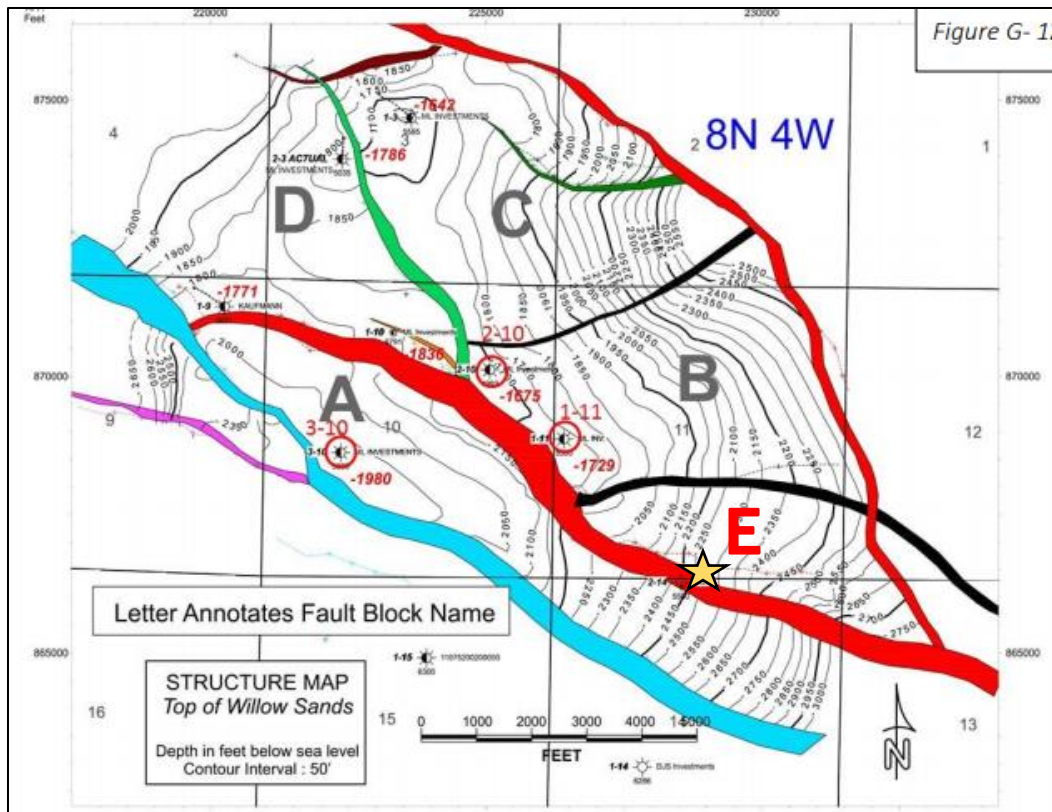


Figure 3 – Structure map of the Willow Sands at Willow Field. Faults depicted by red, green, black, light-blue, and purple ribbons cross-cutting the field. Fault Block E is bound on all sides by three faults. DJS 2-14 is in Block E along a northwest-southeast trending fault (marked with a star). Depth contours correspond to subsea depth to the top of the Willow Sands. Previously drilled production wells ML 1-11, ML 2-10, and ML 3-10 are found in Blocks B, B, and A, respectively.

By convention, these blocks have been named alphabetically, e.g., “Block A” though “Block E.” (See Figure 3, above.) DJS 2-14 is located within Block E. As seen in this figure, three boundaries form Block E: 1) the “northern” fault is between Block B and Block E, 2) the “southwestern” faults are between Blocks A and E, and 3) the “eastern fault” separates Block E from the unlabeled portions of the Willow Sands to the east. The northern and southwestern faults are most important for confinement based on their proximity to DJS 2-14.

EPA considered whether faults separating Block E from surrounding Blocks inhibit migration of fluids. Pursuant to federal regulations, in no case shall injection pressure cause the movement of injection or formation fluids into a USDW (40 CFR §146.23(a)(1)). The Permittee requested EPA exempt all aquifers within the injection zone (i.e., any aquifers within Sands 3-6 of Block E of the Willow Sands) from status as a USDW. If this AE is approved, the permittee could inject into DJS 2-14 (*See* EPA’s ‘Record of Decision: Aquifer Exemption of the Willow Sands’) so long as injected or formation fluids do not migrate outside of Block E. If the AE is not approved, injection could not occur into Block E since it would endanger the existing USDWs within the Willow Sands.

Impermeable layers within or along fault planes can serve as a barrier to fluid movement, effectively

creating lateral fault boundaries. SROG has submitted evidence showing that these faults are impermeable. EPA reviewed this information and reached the conclusion that the faults will prevent fluid movement, pending results of pre-injection testing. A summary of the principal evidence used to reach this conclusion is listed, below:

1. Reservoir pressure data from the Willow Sands suggest that faults isolate Blocks at a field-wide level. This is demonstrated by comparing pressure versus time data for wells drilled into Blocks A and B of the Willow Sands. Two wells drilled into Block B of the Willow Sands, ML 1-11, and ML 2-10, began production in August 2015. In the following months, net fluid withdrawal from this zone created a downward trending bottomhole pressure in both wells. Twenty-eight months after construction of ML 1-11 and ML 2-10, ML 3-10 was drilled into Block A. Initial shut-in tubing pressure in ML 3-10 was at original formation pressure, approximately .43 psi/ft., an indication that fluid withdrawal from Block B did not result in fluid movement from Block A. Net fluid withdrawals from Block A resulted in reduced bottomhole pressures in Block A, but across a significantly different pressure-versus-time profile as compared with Block B (Figure 4).

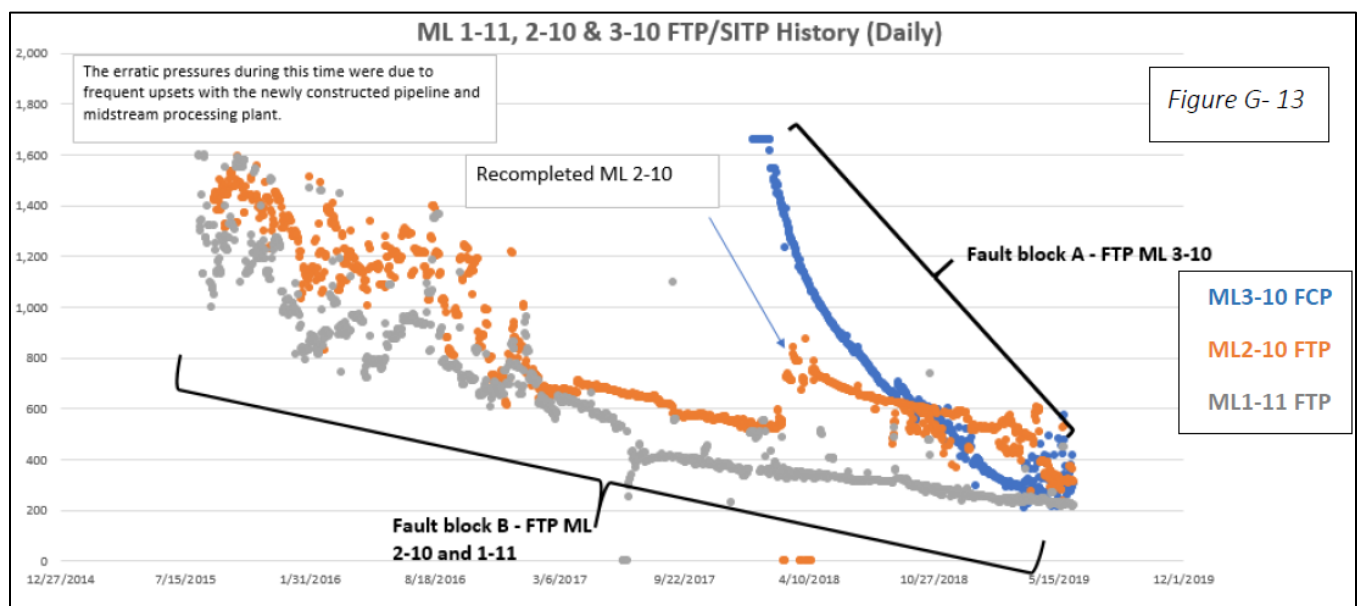


Figure 4 – Flowing Casing/Tubing Pressure (FCP/FTP) across time for ML 1-11, ML 2-10, and ML 3-10.

Note that initial FCP/FTP for all three wells are at approximately 1,600 psi—original reservoir pressure—and drop precipitously as withdrawal occurs. Trends differ between fault blocks. ML 1-11 and ML 2-10 are in Block B, while ML 3-10 is in Block A.

These data are supportive of fault sealing between Blocks A and B. The fault between Block A and B continues to form the southwestern barrier to Block E, separating Blocks A and E. This information supports the position of non-permeable flow across the southwestern fault. This information alone does not prove that this fault is impermeable across its entire length or across all sands within the approved injection zone; rather, it provides localized data indicating likelihood of sealing character.

Other pressure versus time data across the field provide support of fault sealing at a regional level. SROG compared downhole pressure data across other Blocks, providing additional assurance that faults with different orientations, and at different locations across the field, exhibit sealing capacity. For instance, fluid production trends from Blocks B and C demonstrate evidence of fault sealing across east-west trending faults, such as the one that forms the northern boundary to Block E. This information alone is not sufficient evidence to conclude fault containment but is supportive of the notion.

2. Hydrocarbon accumulation and vertical offset of hydrocarbon/water contact points in Blocks other than Block E indicates that geologic structure effectively inhibits fluid movement. Hydrocarbons are trapped against fault and claystone traps between Blocks A and B. The presence of hydrocarbons in commercially relevant volumes against these traps indicates impermeability across a geologic timescale. The hydrocarbon/water contact point, where the oil and gas contact water, a denser fluid, is approximately 200 ft. lower with respect to sea-level in ML 3-10 than wells in Block B (Figure 5, below). Trapping occurs across faults where sand-sand juxtaposition would otherwise be present, indicating that hydrocarbon trapping cannot be solely attributed to a facies change. Hydrocarbon trapping and offset hydrocarbon/water contacts points provide additional evidence of fault containment.

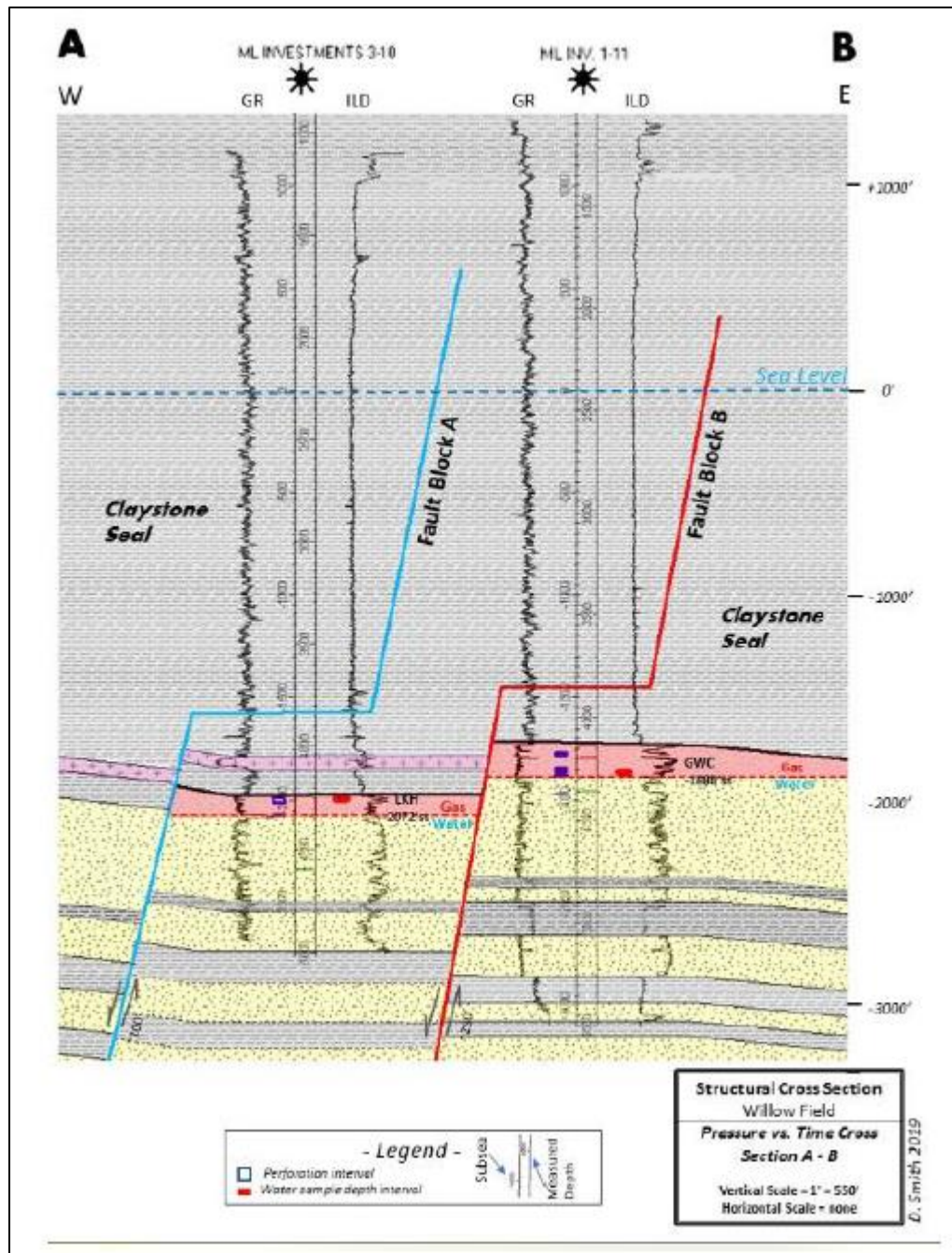


Figure 5 – Hydrocarbon/water contact point between Blocks A and B. Hydrocarbons are trapped against the fault in Block A, inhibiting movement into the upthrown Block B.

3. Two distinct geologic processes seen in geologic outcrops in southwestern Idaho explain the formation of sealing faults. Clay smear, a process in which clay from the wall rock is incorporated in a fault zone, and silica cementation, a process by which percolation of geothermal water precipitates silica in voids of the sands, are geomechanical and geochemical processes affecting fault sealing properties. These two processes, individually or together along the same fault, explain the impermeable nature of the faults at Willow Field. SROG provided

examples of cementation for the Chalk Hills on the western flank of the Western Snake River Plain (about 25 -30 miles southwest of the project site), in the Marsing area (about 40 miles south of the project site), and the Boise area (about 40 miles from the project site on the eastern margin of the WSRP) where faults are exposed at the surface. The occurrence of numerous claystone/sandstone transitions within the Willow Sands increases the likelihood of clay smear. Regional geothermal activity increases the likelihood of silica cementation.

4. Subsurface imaging identified syndepositional faults at Willow Field, and historic seismic records indicate a lack of seismicity in the project area. This supports the conclusion that the faults are inactive and have not deformed since time of formation.

Multiple lines of evidence indicate that faults forming the segmented Willow Field Blocks are sealing. To fully evaluate whether specific faults found at Block E prevent movement of injected fluids into USDWs, EPA requires the Permittee to gather data prior to well injection that will confirm fault containment. EPA is applying requirements beyond those typical for Class II permits pursuant with 40 CFR §§144.52(a)(3) and 144.52(a)(9), which allow the Director to apply site-specific permitting conditions. These conditions require the permittee to measure static reservoir pressures across Blocks and perform a Pressure Fall-Off Test (PFOT) capable of identifying whether faults form a barrier to fluid movement (i.e., boundary effects) within the reservoir. This information along with other data and graphics concerning fault confinement must be submitted to EPA as part of a Boundary Effects Analysis Report (BEAR). EPA will not grant approval to inject if testing and monitoring fails to confirm full sealing capabilities across faults forming Block E.

Additionally, to assure that faults do not become transmissive after approval to inject is granted, EPA is requiring ongoing testing and monitoring to evaluate confinement through the life of the Permit. BEARs must be submitted annually to confirm ongoing isolation of the fault system. If the results of ongoing testing and/or monitoring indicate faults are no longer acting as complete barriers to fluid movement, the Permittee must shut-in the well and notify the Director. If the Permittee cannot verify that injection will continue to occur in a manner protective of USDWs, EPA may require additional testing, revoke and reissue the permit, or terminate the permit.

Seismicity

Under certain conditions, disposal of fluids through injection wells causes seismic events, a phenomenon referred to as “induced seismicity.” This occurs when injection of fluids increases pore pressure within an existing stressed fault to a point of overcoming frictional forces holding a stressed fault in place, resulting in slip. Fault slippage may create a new pathway for fluid movement. It also may create a seismic moment capable of being felt at the surface. EPA considered these two concerns in review of this permit application.

First, EPA considered whether an induced seismic event could result in movement of fluids into a USDW by forming a new conduit for fluid movement. There are approximately 30,000 Class II active disposal wells in the United States used to dispose of oil and gas related wastes, many of which have

operated for decades, and EPA is unaware of any USDW contamination resulting from seismic events related to injection-induced seismicity⁶. Due to the proximity of faults within the AOR and lack of historical injection practice in this region, EPA considered seismic risk associated with DJS 2-14. Following review, EPA concluded that the proposed injection activity does not pose a risk of initiating fault movement. This determination is based on the constraints imposed by the permit which establish a Maximum Allowable Injection Pressure (MAIP) and results of fault slip modeling performed by the Permittee.

Class II injection wells are typically allowed to inject at pressures that would fracture the formation. Due to the proximity between the injection zone and USDWs, EPA is requiring the Permittee to operate the injection at a pressure below the formation fracture pressure of both the injection and confining zones. EPA determined that this limitation is required to ensure injection does not create a pathway for fluid movement. Additionally, the MAIP required by this permit includes safety factors to ensure formation fracture pressure is not exceeded: 1) the injection pressure may never exceed 90% of the formation fracture pressure, and 2) 0.05 specific gravity fluctuation factor is included in the MAIP calculation to ensure minor fluctuations in the weight of injected fluids do not raise downhole pressures above the formation fracture pressure. Finally, the Permittee must continuously monitor injection pressure to ensure injection does not exceed MAIP. These permit conditions will ensure injection occurs below the fracture pressure of the injection zone.

To evaluate whether increased reservoir pressure could induce movement along a vulnerable fault before reaching the fracture pressure of the rock matrix, the Permittee conducted a Fault Slip Potential (FSP) analysis that yielded the probability of each fault forming a boundary to Block E slipping as a function of pore pressure increase. Use of the FSP software consisted of three types of analysis, a base case followed by two different probabilistic types of sensitivity analysis:

- First, the Mohr-Coulomb pore pressure needed to trigger slip on each fault was calculated using a deterministic approach.
- Second, a Monte-Carlo analysis of the pore pressures (based on the values generated in the first step) to trigger slip was run for each fault. This yielded the probability of each fault slipping as a function of pore pressure increase.
- The third analysis was a probabilistic Monte Carlo analysis in which the geomechanical stress model parameters were varied.

FSP modeling showed that faults would not slip based on the expected reservoir pressure increase due to injection. SROG calculated the expected formation fracture pressure by assuming a 12 pound per gallon fracture gradient, and then estimated a maximum injection pressure at 10% below that value resulting in

⁶ Minimizing and Managing Potential Impacts of injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. Underground Injection Control National Technical Workgroup. U.S. Environmental Protection Agency. November 12, 2014

a planned maximum injection pressure of 616 psi above formation pressure. Note that the actual fracture gradient will be determined by a step rate test prior to receiving approval to inject, and that the permit sets a maximum injection pressure by formula.

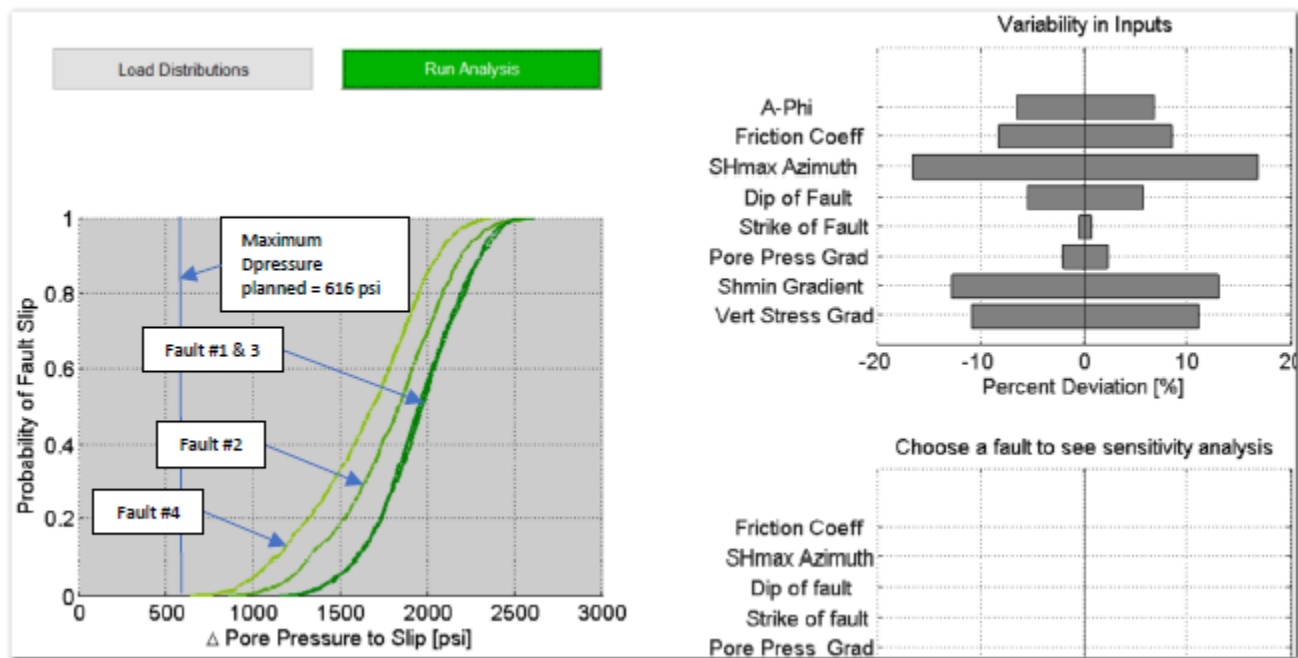


Figure 6 – Results of FSP modeling showing change in pressure to fault slippage. Change in pore pressure caused by injection is on the x-axis, and probability of fault slip is displayed on y-axis. Fault 1 and 2 form the southwest border of Block E, fault 3 forms the eastern border, and fault 4 forms the northern border.

To ensure faults do not pose a realistic possibility of slippage, the maximum injection pressure is set to either a formula calculation involving formation fracture gradient or an increase above original reservoir pressure of 616 psi, whichever is lower.

To monitor possible fracture activation over time, EPA is requiring downhole PFOTs to confirm the existence of sealing fault boundaries. Following a PFOT, SROG must analyze the results and identify boundary effects encountered by pressure transients in a BEAR. If these boundary effects do not indicate full confinement of fluids by faults, the Permittee must stop injection. The BEAR must also include a Hall Plot, which will provide information on how injected fluids interact with the formation rock over time, and a comparison of the actual reservoir pressure against the pressure expected based on total barrels of injected fluids into a confined reservoir. In total, the results of the BEAR will be used to confirm that faults continue serving as fluid barriers even after injection begins.

EPA evaluated whether injection through well DJS 2-14 could result in seismic event that could be felt at the surface using a decision model⁷ from the EPA UIC National Technical Workgroup. This guide identifies three key characteristics related to potential injection-induced seismicity that may lead to induced seismicity: (1) sufficient pressure buildup from disposal activities, (2) presence of a Fault of Concern, and (3) a pathway allowing the increased pressure to communicate from the disposal well to the Fault of Concern. Typically, induced seismic events that can be felt at the surface involve disposal of large quantity of fluids near basement rock, or near a fault connected to basement rock.

EPA considered whether Faults of Concern exist near the injection well disposal zone since these is a key characteristic common to cases of felt seismicity. A Fault of Concern is a fault oriented for movement and located in a critically stressed region that that occur within—or extend into—granitic basement rock. No known Faults of Concern are located near the injection well. There are redundant lower confining zones immediately below the lower portion of the injection zone serving as barriers to downward fluid movement. The proposed well terminates in the injection zone at a depth of 5,500 ft., while the depth to granitic basement rock is approximately 13,000-15,800 ft. Additionally, Historic seismic activity is an indicator of critical stress in basement rocks. Few earthquakes have occurred in the Western Snake River Plain since 1900⁸, and across that time span there are no records of earthquakes occurring within a ten-mile radius of DJS 2-14. While Idaho as a whole is considered a seismically active state, the local area near the injection well is quite inactive.

Based on the lack of historical seismicity near the injection well and improbability of injected fluids reaching a Fault of Concern, EPA determined that it is highly unlikely that injection results in a seismic event that would be felt at the surface. Since there is no history of injection at this location, this Permit includes conditions that require the permittee to monitor existing seismic networks for seismic events and stop injection and notify EPA immediately when nearby seismic activity occurs. The permittee must demonstrate that all USDWs are protected before EPA will approve injection after a seismic event.

Corrective Action Plan

If any well in the AOR is improperly sealed, completed, or abandoned, the permittee must develop and implement a Corrective Action Plan prevent movement of fluid into USDWs. No corrective action is required at this time, as no wellbores exist within the Area of Review.

⁷ Minimizing and Managing Potential Impacts of injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. Underground Injection Control National Technical Workgroup. U.S. Environmental Protection Agency. November 12, 2014

⁸ USGS Earthquake Catalog. <https://earthquake.usgs.gov/earthquakes/search/>

PART V. Well Operation Requirements

Mechanical Integrity (40 CFR § 146.8)

The Permit requires mechanical integrity (MI) to always be maintained. An injection well has MI if:

- (1) There is no significant leak in the casing, tubing, or packer (Internal MI); and
- (2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (External MI).

The Permittee must demonstrate MI prior to injection. In addition, the Permittee has requested, and EPA requires, demonstration of MI every three years thereafter. Due to the proximity of USDWs to the injection well, EPA is requiring more frequent monitoring and specific testing conditions. A demonstration of well MI includes both Internal and External MI. The methods for demonstrating MI are described below.

Internal MI is demonstrated by an Internal Mechanical Integrity Test (Internal MIT). An Internal MIT is also required following any workover operation that affects the tubing, packer, or casing, and after a loss of MI. In such cases, the Permittee must restore MI within 90 days following the workover or within a timeframe approved by EPA. After the well has lost MI, injection may not resume until after internal MI has been demonstrated and EPA has provided written approval.

External MI is required to demonstrate that injected fluids are not migrating outside of the approved injection zone. Due to the proximity of this injection well to a fault and the USDW contained within Block A of the Willow Sands, EPA is specifying that a fluid movement test must be used to demonstrate External MI. Approved fluid movement test types include temperature logging, radioactive tracer survey, or an oxygen activation log. Alternative methods may be used if those methods can identify fluid movement above the proposed injection zone and have been approved in writing by EPA. This test shall be performed at a frequency no less than once every three years. After an initial test, and at the discretion of the Director, EPA may accept an evaluation of cement records in place of a fluid movement test to satisfy this requirement.

Injection Fluid Limitation

Injected fluids are limited to those identified in 40 CFR § 144.6(b). This includes those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection. Wastes that meet the definition of hazardous waste as defined by the Resource Conservation and Recovery Act and are not subject to the Exploration and Production Exemption, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection. This well is not approved for injection of third-party wastes.

Examples of fluids which may be approved include, but are not limited to: produced water, drilling

fluids, used well completion, treatment and stimulation fluids, water and other tank bottoms from oil and gas production storage facilities, well workover waste, liquid hydrocarbons removed from the production stream but not from oil refining, waste crude oil from primary field operations, and materials ejected from a producing well during blowdown.

Examples of prohibited fluids include, but are not limited to: unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, painting wastes, waste solvents, oil and gas service company wastes, vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, refinery wastes, liquid and solid wastes generated by crude oil and tank bottom reclaimers, used equipment lubricating oils, waste compressor oil, used hydraulic fluids, waste in transportation pipeline related pits, caustic or acid cleaners, boiler cleaning wastes, boiler refractory bricks, boiler scrubber fluids, sludges, incinerator ash, and lab waste.

Prior to injecting fluid from a new source, the Permittee must provide a sample analysis to EPA for any waste stream not previously characterized. A new source may include fluids from a different formation, a different well, a new portion of the field, or a source that is chemically dissimilar from fluids that are already injecting into the well. Section D of the Permit lists required sampling methods and analysis methods. New sources (including sampling prior to receiving approval to inject) must be analyzed for a broad set of chemical analytes to gather a chemical signature of the new injection stream. All samplings, including annual samples, must include an analysis of at least TDS, pH, and specific gravity. This is to ensure ongoing performance of the injection well within permit limits. As a result of a sample analysis the MAIP may need to be recalculated due to changes to variables used in the calculation.

Injection Pressure Limitation

40 CFR § 146.23(a)(1) requires that the pressure at the wellhead for a Class II well must not exceed an MAIP calculated to ensure that injection does not initiate new fractures or propagate existing fractures near USDWs. Based on the proximity of faults separating the injection zone from USDWs, EPA has determined that injection shall be limited to a pressure that will not fracture any formation, whether the formation is identified as an injection zone or a confining zone. This limitation is to ensure that increased pressure does not cause slippage along faults which could result in movement of fluids into a USDW. Additionally, the MAIP is set 10% below the estimated fracture pressure to serve as a safety buffer against fracturing of the injection zone. The Permittee has not requested consideration of friction loss at this time but may request that tubing friction and perforation friction be considered when calculating the MAIP. This request must be submitted to EPA for approval and be supported by demonstration of the effects of friction. The MAIP allowed under the Permit, as measured at the surface, will be calculated according to the equations below:

$$\text{MAIP} = (\text{FFP} \times .90 + \text{friction loss})$$

Formation Fracture Pressure (FFP) is a primary component of this equation, and is defined as:

$$\text{FFP} = [\text{FG} - (0.433 \text{ psi/ft.} \times (\text{SG} + \text{SGFF}))] \times \text{D}$$

Where:

FFP is the pressure above which injection of fluids will cause the rock formation to fracture.

FG is the fracture gradient in psi/ft.

SG is the specific gravity of the injection fluids obtained from the fluid analysis of a representative sample,

SGFF is the Specific Gravity Fluctuation Factor, set at .05 to account for minor fluctuations in fluid weight.

D is the depth of the top perforation in feet.

The fracture gradient for the injection well will be determined by a step rate test conducted by the Permittee. Test methods are to be submitted to EPA approval and should be based on the Step-Rate Test Procedure guidance published by the EPA Region 8 UIC Program⁹, unless otherwise stated by the Director. Bottom-hole and surface gauges are required during the test. This requirement may be waived by EPA if the Permittee can demonstrate that a surface pressure gauge alone will provide accurate results.

During the operational life of the injection well the terms used to calculate the MAIP (**D**, **FG**, **SG**) may change. When injection well workover records, tests, sample analysis, or monitoring reports indicate one of the variables used to calculate the MAIP has changed, the Permittee must review the MAIP calculation and submit a request for a new MAIP to EPA.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and demonstrate that the fracture gradient value is representative of the portion of the injection interval proposed for perforation. The Permittee must run a step rate test to provide representative data, such as when a new formation within the approved injection zone or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

The Permittee must also submit fluid analyzes for SG annually and more frequently when a new source is introduced. This may result in the need to request a new MAIP.

If the Permittee is unable to conduct an External MIT at a pressure equal to the MAIP, or unable to conduct an Internal MIT with an annulus pressure equal to the MAIP, the new permitted MAIP will be

⁹ <https://www.epa.gov/uic/region-8-step-rate-testing-guidelines>

set at the highest pressure achieved during the respective MIT. This limitation is to ensure that the injection conditions during a test represent the highest pressure imposed well componentry.

The MAIP cannot exceed a value that would result in a bottomhole injection pressure exceeding the sum of the original formation pressure (as measured during pre-injection testing) and 616 psi. This is to ensure that maximum injection pressure does not exceed a limit that could impact fault activation. This requirement may be waived or modified by the Director only if the Permittee can demonstrate that a higher injection pressure will not activate faults near the injection well by submitted an FSP analysis.

Injection Volume Limitation

There is no daily maximum volume injection. Based on expected compression of fluids and pore space within Block E, limiting injection to below 7.368 million stock tank barrels will ensure pressures do not exceed for formation fracture pressure. Based on a calculation of the expected injection reservoir capacity, this permit establishes a lifetime injection volume limit of 7.35 million barrels, or approximately 300 million gallons of fluid. This calculation was based on a consideration of reservoir characteristics and anticipated effects of injection. Physical parameters of the reservoir used in calculating this limit are provided in Attachment H of the Permit Application submitted by the applicant on March 4, 2020.

PART VI. Monitoring, Testing, and Reporting Requirements

Monitoring

The UIC regulations set forth the monitoring requirements for Class II injection wells, 40 CFR § 146.23(b). The regulations require, at a minimum, monitoring of injected fluid at regular intervals; weekly monitoring of injection pressure, flow rate, and cumulative volume; and MITs once every five years. EPA is requiring more stringent monitoring requirements than the minimum regulatory requirements based on the proximity between the injection zone and USDWs within the Willow Sands. Failure to monitor the parameters of injection at the frequency stipulated by EPA could result in endangerment of USDWs. Injection Well Monitoring is specified in Section D of the Permit.

EPA requires daily monitoring of flow rate at two points along the flowline connecting the injection pump to the injection well: one immediately downstream of the injection pump, and another at the injection wellhead. This information is required to detect leakage in the pipeline to the injection well and will ensure that accurate volume measurements are recorded. The Permittee must ensure compliance with all applicable federal, state, and local requirements for pipeline transmission of produced fluids.

Logging and Testing

EPA permits require the Permittee to conduct tests and well logging to ensure protection of USDWs. Logging and Testing requirements are found in Section C of the permit. Any requirements described in this section that are more stringent than those established by the CFR are required due to the proximity between the proposed injection zone to USDWs, and the occurrence of nearby faults (i.e., fault between Block A and Block E within the AoR) near DJS 2-14. EPA has authority to set such requirements (see, 40 CFR §144.52(a)(9)).

Due to the proximity of the injection zone to nearby USDWs, the Permittee must conduct reservoir pressure monitoring to confirm hydraulic isolation to Block E before injection is approved. This monitoring plan includes the measurement of bottom hole pressures in four wells within three fault blocks, including the fault block where injection will occur (Fault Block E) and the fault blocks to the north (Fault Block B) and west (Fault Block A). The Permittee will gather this data by measuring static reservoir pressure in DJS 2-14 and ML 1-11, and pressure build-up tests in ML 3-10 and ML 2-10. This information must be collected prior to the start of injection. Fault Block E is expected to be at or near an original pressure gradient of approximately 0.43 psi/ft. and Fault Blocks A and B are expected to be significantly below the original pressure gradient. Fault confinement will be demonstrated if Fault Block E is at original reservoir pressure and Fault Blocks A and B are significantly lower than original pressure. If downhole pressure in Block E is below original formation pressure, one explanation may be that fluids have moved down a hydraulic gradient out of Block E established by fluid withdrawal from Block A or B. This would indicate movement of fluids across nearby fault boundaries. In such a scenario, EPA would be within its right to inhibit injection into this well.

The Permittee must conduct long-term testing and monitoring to confirm hydraulic isolation between

fault blocks over the life of the injection well. PFOTs must be conducted within the first 30 days of injection, and annually thereafter. A PFOT consists of fluid injected into a well at a constant rate for long enough to investigate a radial distance from the well, followed by shut-in of the well and monitoring the pressure decline. Prior to conducting the test, the Permittee must share testing protocol with EPA for review and approval to ensure testing conditions will generate data needed to evaluate fluid boundary effects. The protocol should be based on existing EPA guidance¹⁰. The PFOTs will be run for a length of time necessary to observe a pressure fall-off curve, and to make accurate estimates of permeability, average reservoir pressure, and identification of bounded reservoir characteristics. If the Permittee encounters complex test results, convolution techniques should be used to emulate ideal test conditions to identify boundary effects.

The results of PFOT testing will be used to confirm continued isolation of the injection reservoir. PFOT analysis and results will be submitted to EPA as an annual BEAR. Other components of this report—such as the fluid distribution map and Hall Plot—are used to track anticipated dispersal of fluid and identify possible fracture flow, respectively. This information will provide ongoing confirmation that faults near the injection well continue to act as barriers to fluid movement. If results do not conclusively demonstrate that faults near the injection well are sealing, EPA will be within its right to require that the Permittee halt injection if USDWs may be endangered.

Movement of fluids outside the intended zone may be detectable by pressure monitoring in neighboring Blocks. The Permittee will monitor reservoir pressure for wells ML 2-10 and 1-11 (in Fault Block B), and ML Investments 3-10 (in Fault Block A) to detect flow outside of the injection zone. The Permittee will conduct pressure build-up transient pressure tests on active wells, ML 2-10 and ML 3-10, on an annual basis to determine average reservoir pressures. Following an initial static pressure measurement in shut-in well ML 1-11, the Permittee may use an echometer to determine reservoir pressure based on fluid level. If pressure measurements in offset wells increase, the permittee must shut-in DJS 2-14 and investigate possible fluid migration across faults forming Block E. An increase in downhole reservoir pressure as measured by an offset well (i.e., a well in Block A or B) does not necessarily mean that fluids are migrating outside of the approved injection zone but may be indicative of this outcome. If the Permittee cannot demonstrate that USDWs are protected from fluid movement outside of Block E, EPA is within its right to require that the Permittee halt injection.

Reporting

The annual report must include all required data collected over the reporting period. The initial reporting period begins upon the effective date of this Permit and extends until December 31. In subsequent years, the reporting period is from January 1 through December 31. This report must be submitted to EPA by February 15 of each year. EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report; however, the monitoring requirements specified in this permit are mandatory even if the EPA

¹⁰ EPA Region 6 UIC Pressure Falloff Testing Guideline (Third Revision)

form indicates otherwise. The annual performance report must include:

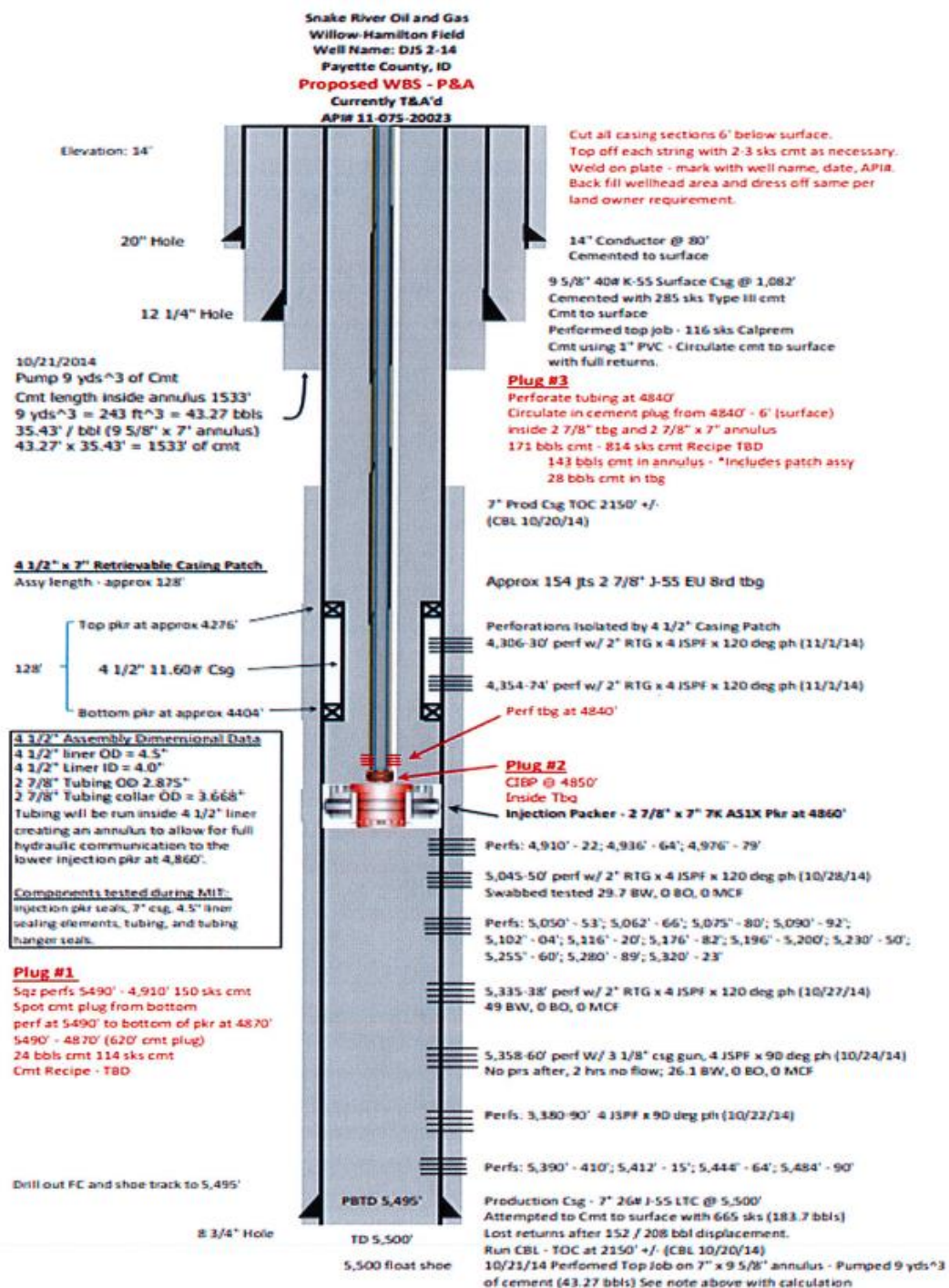
- the results of the sampling required by Section D, including the laboratory analytical results and a summary of any major changes in characteristics or sources of injected fluid. The report must identify each new fluid source by well name and location, and the field name or facility name;
- a summary of all monitoring listed in the table in Section D.4., including all data recorded at the applicable reporting frequency;
- a summary of all logging and testing results that occurred in the reporting year; and
- a description of any wells located within the area of review that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records, and cement bond logs are also required.

A BEAR must be submitted to EPA 60 days after the completion of every PFOT. Additional reporting is required in event of non-compliance and/or loss of MI. This includes a 24-hour notification requirement.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

In accordance with 40 CFR §§ 146.10, the well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs. EPA has approved the P&A plan submitted by the applicant on June 17, 2021 and included below:

Attachment Q-1 Proposed Post-Injection Plug and Abandon Wellbore Diagram



Within 30 days after plugging the permittee must submit a Plugging Record (EPA Form 7520-14) to EPA. The Plugging Record must be certified as accurate and completed by the entity responsible for the plugging operation. The plugging and abandonment plan is described in Appendix C of the Permit.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

The Permittee must maintain financial responsibility and resources to close, plug, and abandon the injection well in a manner prescribed by EPA. The Permittee will show evidence of such financial responsibility to EPA by the submission of completed original versions.

The Permittee has submitted a surety bond with a standby trust agreement provided by Bancorp South Bank, an FDIC insured bank. The value for this instrument is \$100,000 dollars, while the estimated cost for plugging and abandoning the well is \$69,250.

EPA may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The Permittee may also provide an alternative demonstration of financial responsibility.

PART IX. Considerations Under Other Federal Laws

This Permit complies with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act, the Endangered Species Act, and Executive Order 12989 (Environmental Justice).

National Historic Preservation Act (NHPA)

Section 106 of the NHPA, 54 U.S.C. § 306108, requires federal agencies to consider the effects of actions they authorize, fund, and/or carry out on historic properties. Authorization of injection under this permit action constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800. EPA consulted with Idaho's State Historic Preservation Office (SHPO), regarding the Area of Potential Effects associated with this project and requesting evaluation under NHPA Section 106. The SHPO determined that the proposed project actions will not affect any historic properties. EPA concurs with SHPO's determination.

Endangered Species Act (ESA)

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. EPA has determined that a decision to issue a Class II permit for authorization of injection into the DJS 2-14 well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402).

EPA has determined that there are no endangered species, nor any critical habitat as defined by the U.S. Fish and Wildlife Service, within the area of the proposed project. Certain birds may be at this location that are protected under the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act, and any person or organization who plans or conducts activities that may result in impacts to migratory birds, eagles, and their habitats should follow appropriate regulations and consider implementing appropriate conservation measures. More information can be found by reviewing the Migratory Birds Treaty Act of 1918, The Bald and Golden Eagle Protection Act of 1940, and 50 CFR Sec. 10.12 and 16 U.S.C. Sec. 668(a).

Executive Order 12898

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." EPA has concluded that the specific conditions of this permit will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of Environmental Justice concern. The UIC program will be conducting public outreach by publishing a public notice announcement in local newspapers and holding a public hearing.

PART X. Public Comment

Comments on this proposed permit must be submitted during the public comment period beginning on January 14, at 9:00 AM Mountain Time (MT) and ending on February 28, 2022, at 5:00 PM MT. Due to the Covid-19 pandemic, no hard-copy comments will be accepted. All comments must be submitted by email. **All comments MUST be submitted by email to osborne.evan@epa.gov AND contain:**

- i. The statement “Draft Permit Public Comment” in the subject line of the email,
- ii. The name, address, and telephone number of the person commenting (in the body of the email) and,
- iii. A concise statement and the relevant facts forming the basis for the comment.

EPA has scheduled a public hearing on February 18, 2022, at 10:00 AM MT. The purpose of this meeting is to collect oral comments on the actions proposed by this notice. To attend the meeting, visit the EPA Region 10 UIC webpage (<https://www.epa.gov/uic/underground-injection-control-region-10-ak-id-or-and-wa>) the morning of the hearing. EPA will post hearing details under the Public Notices section of this webpage.

After the public comment period ends and all comments have been considered, the Director will make a final decision regarding permit issuance. If no substantive comments are received, the conditions in the proposed permit will become final, and the permit will become effective upon issuance. If substantive comments are received, EPA will address the comments and determine whether to issue the proposed permit. The permit will become effective upon issuance unless an appeal is submitted. Appeals regarding the SDWA UIC Class II permit should be submitted to the Environmental Appeals Board within 30 days of issuance pursuant to [40 CFR § 124.19](#).

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