UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

OGLALA SIOUX TRIBE, BLACK HILLS CLEAN WATER ALLIANCE, NDN COLLECTIVE	)	
Petitioners,	)	No. 21-1167
v.	)	
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY	)	
Respondent.	)	

SUPPLEMENTAL PETITION FOR REVIEW

Pursuant to 42 U.S.C. § 300j-7(1) and Federal Rule of Appellate Procedure 15, notice is hereby given this 12th day of November, 2025, that Petitioners Oglala Sioux Tribe, Black Hills Clean Water Alliance, and NDN Collective through undersigned counsel, hereby file this Supplemental Petition the United States Court of Appeals for the Eighth Circuit for review of the United States Environmental Protection Agency Region 8 Underground Injection Control Program Aquifer Exemption Record of Decision ("Aquifer Exemption ROD") for the Dewey-Burdock In-Situ Recovery Project in Custer and Fall River Counties, South Dakota, dated November 24, 2020 (attached as Exhibit 1); and the United States

Environmental Protection Agency Region 8 Underground Injection Control Program final underground injection control (UIC) permits for UIC Permit Nos. SD31231-00000 and SD52173-00000, issued following the Environmental Appeals Board's (EAB) September 12, 2025 Order Denying Review (attached as Exhibit 2).

The Oglala Sioux Tribe filed its initial Petition for Review regarding the Aquifer Exemption ROD on January 22, 2021. On March 9, 2021, the Court issued an Order approving the request of the Oglala Sioux Tribe and EPA to hold the case in abeyance until related administrative and judicial proceedings were resolved. Pursuant to the Order, the parties filed a series of Joint Status Reports that described the interrelated administrative actions and judicial review that took place during the stay. The bases for the stay have now been resolved. The last basis for the stay was resolved when the UIC permits were reissued and became effective October 25, 2025.

The Oglala Sioux Tribe now updates its Petition to Review by filing this Supplemental Petition to ensure the interrelated actions approving injection of process chemicals and radioactive materials into an aquifer for purposes of uranium production, and which involve substantially overlapping factual and legal issues, are included in a single appeal, which was initially filed to address the Aquifer Exemption ROD. This Supplemental Petition thus adds Petitioners Black

Hills Clean Water Alliance and NDN Collective, both of which, along with the Oglala Sioux Tribe, exhausted administrative remedies in appealing the Final UIC Permits to the EAB.

The Aquifer Exemption ROD, the final Class III and Class V underground injection control permits, and the actions underlying the aquifer exemption and UIC final permit are final agency actions ripe for judicial review, violate the Administrative Procedure Act, 5 U.S.C. § 706, the National Environmental Policy Act, 42 U.S.C. §§ 4321, *et seq.*, the National Historic Preservation Act, 16 U.S.C. §§ 470, *et seq.*, the Safe Drinking Water Act, 42 U.S.C. §§ 300f, *et seq*., and implementing regulations.

Respectfully submitted,

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Filed this 12th day of November, 2025

EXHIBIT 1

United States Environmental Protection Agency Region 8 Underground Injection Control Program Aquifer Exemption Record of Decision ("ROD") for the Dewey-Burdock In-Situ Recovery Project in Custer and Fall River Counties, South Dakota, dated November 24, 2020

U.S. EPA Region 8

Underground Injection Control Program

AQUIFER EXEMPTION RECORD OF DECISION

This Record of Decision provides EPA's aquifer exemption (AE) decision, background information concerning the AE request, and the basis for the AE decision requested by Powertech (USA) Inc. for the Dewey-Burdock uranium in-situ recovery (ISR) site in Custer and Fall River Counties in South Dakota.

Primacy Agency: EPA Region 8 Direct Implementation Program under Section 1422 of the Safe Drinking Water Act (SDWA) for the State of South Dakota

Date of AE Request: January 2013

Major or Minor (Substantial or Non-Substantial) Approval: **Minor** (**Non-Substantial)**

While the action before EPA is not a state program revision, but rather an approval of an AE in a federally-administered program, the process is treated similarly and requires EPA to determine whether the AE approval is major or minor (i.e. substantial or non-substantial). The process is discussed in the Preamble of 49 Fed. Reg. 40098, 40108 (September 2, 1983); see also 49 Fed. Reg. 20138, 20143 (May 11, 1984). The review and/or approval process differs depending on whether EPA treats the decision as a major or minor program revision. EPA has determined this AE decision is minor, or non-substantial, because it is associated with the issuance of a site-specific UIC Class III permit action, not a state-wide programmatic change or a revision with implications for the national UIC program. The decision to treat this AE as a minor, non-substantial program revision is also consistent with the corresponding state program revision process detailed in EPA Guidance#34: *Guidance for Review and Approval of State Underground Injection Control (UIC) Programs and Revisions to Approved State Programs*. Guidance 34 explains that the determination as to whether a program revision is substantial or non-substantial is made on a case-by-case basis, and with the exception of AEs associated with certain Class I wells or exemptions not related to action on a permit, AE requests are typically treated as non-substantial program revisions.

Operator: Powertech (USA) Inc. (Powertech)

Well/Project Name: Dewey-Burdock Uranium In-Situ Recovery Project

Well/Project Permit Number: EPA Permit No. SD31231-00000

Well/Project Location: Portions of Sections 20, 21, 27, 28, 29, 30, 31, 32, 33, 34 and 35 of Township 6S, Range 1E and portions of Sections 1, 2, 3, 4, 5, 10, 11, 12, 14 and 15 of Township 7S, Range 1E

County: Custer and Fall River **State**: SD

Well Class /Type: Class III uranium in-situ recovery

BACKGROUND

The purpose of this AE is for the injection of lixiviant into the uranium-bearing portions of the Inyan Kara Group aquifers for ISR of uranium. Powertech requested this AE as part of a UIC Area Permit Application for the Class III injection wells that will be used for the injection of lixiviant. The proposed Dewey-Burdock uranium ISR site is located southwest of the Black Hills in South Dakota on the South Dakota-Wyoming state line in southwest Custer and northwest Fall River Counties as shown in Figure 1. The site is located approximately 13 miles northwest of Edgemont, SD and 46 miles west of the western border of the Pine Ridge Reservation.

EPA developed a Fact Sheet for the draft Class III Area Permit that provides more detailed information about the Dewey-Burdock Project and the draft Class III Area Permit requirements. Information about changes EPA made to Class III Area Permit requirements from the 2019 draft to the final versions are discussed in the document entitled *EPA Region 8 Underground Injection Control (UIC) Program Response to Public Comments.*

The ISR process involves the injection of lixiviant, consisting of injection interval groundwater with added oxygen and carbon dioxide, into uranium ore deposits targeted by 14 proposed wellfields. Powertech anticipates the construction of approximately 1,461 Class III injection wells and 869 production wells over the life of the project. The lixiviant is pumped into the uranium deposit through the injection wells and mobilizes uranium from the ore deposits. Production wells pump the uranium-bearing lixiviant out of the ground. The uranium-bearing lixiviant flows via pipeline from the wellfield to a processing unit where ion exchange resin columns remove the uranium from solution. The barren lixiviant is pumped from the processing unit back to the ISR wellfield where oxygen and carbon dioxide are added before injection back into uranium ore deposits through the wellfield injection wells.

Figure 2 shows the Dewey-Burdock Project Area outlined by the black Project Boundary. The Project Area is divided into the Dewey and Burdock Areas identified in Figure 2. Each ISR wellfield has a perimeter ring of monitoring wells completed in the injection zone around each wellfield as shown in Figure 2. Each perimeter monitoring well ring will be located about 400 feet from the injection and production wells completed in the ore deposits. The color of the ore deposits and the perimeter monitoring well rings indicates where the ore deposits occur vertically in the Inyan Kara Group aquifers shown in the stratigraphic column in Figure 3.

DESCRIPTION OF APPROVED AE

Exempted Aquifers

The aquifers approved for exemption are the Inyan Kara Group aquifers: the Fall River Formation and the Lakota Formation, Chilson Sandstone Member, shown in Figure 3. EPA approved the exemption of Inyan Kara aquifers 1,020 feet from the currently defined ore deposit boundaries for Burdock Wellfields 1 through 5 and 9 as shown by the purple-dashed line in Figure 2. EPA also approved the exemption of Inyan Kara aquifers 520 feet from the currently defined ore deposit boundaries for Burdock Wellfield 10 and Dewey Wellfields 1 through 4 as represented by the green dashed line in Figure 2. EPA did not approve the requested exemption of Inyan Kara aquifers for Burdock Wellfields 6, 7 and 8 because Powertech must provide the Director with an analysis of the amenability of the mining zone to the proposed ISR mining method per § 144.7(c)(1) and Class III Area Permit Part II, Section G.

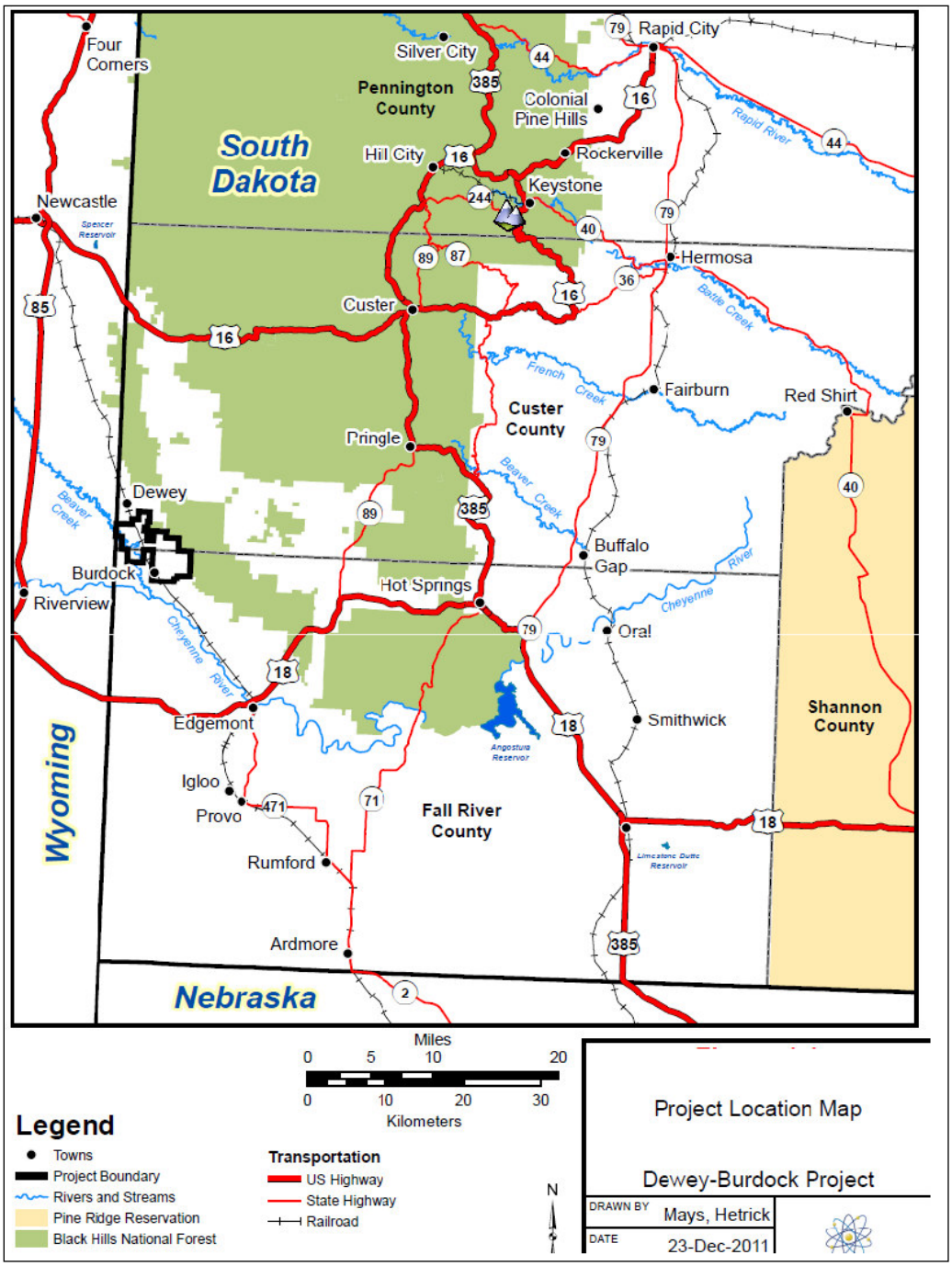


Figure 1. Dewey-Burdock Project location

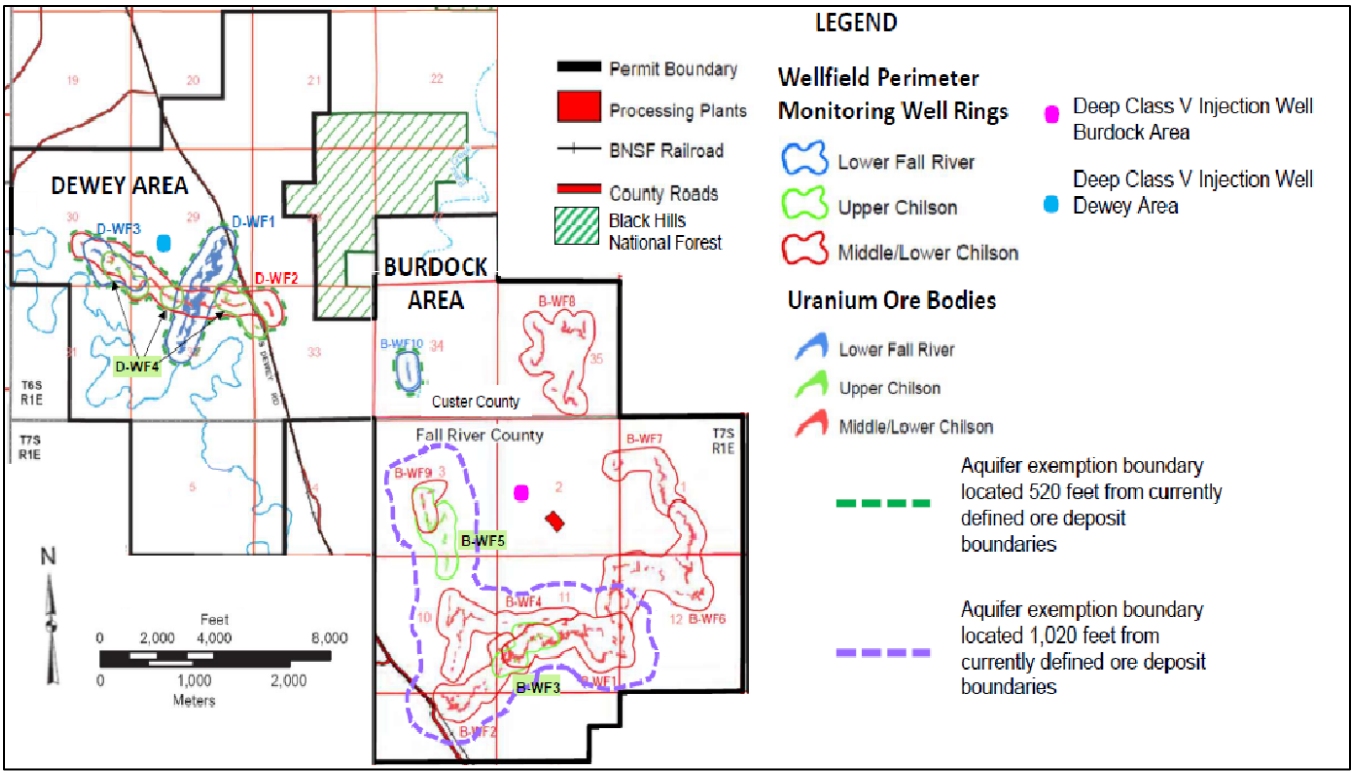


Figure 2. Areas of the Inyan Kara Group aquifers approved by this Record of Decision.

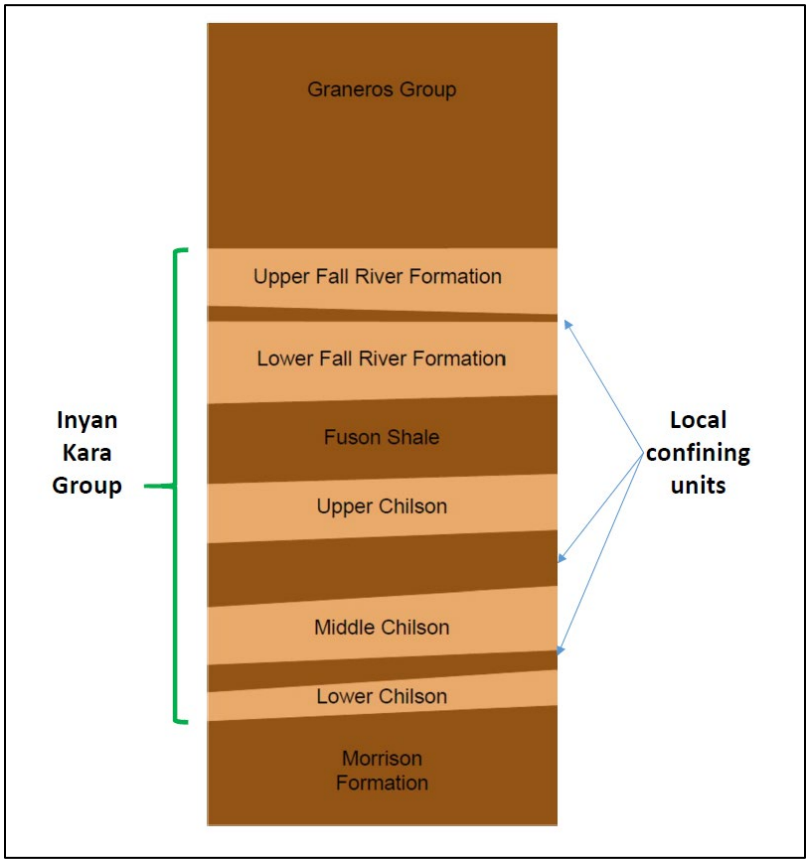


Figure 3. Stratigraphic column of the Inyan Kara Group, major confining zones, and the local confining units.

Water Quality – Total Dissolved Solids (TDS) (mg/L) mg/L

Fall River Formation of the Inyan Kara Group TDS Range: 773.85 -2,250.00 mg/L; mean TDS=1,275.01 mg/L, based on the summary of groundwater quality analyses in Appendix N of the Class III Permit Application.

Chilson Sandstone unit of the Lakota Formation of the Inyan Kara Group TDS Range: 708.33 mg/L-2,358.33 mg/L; mean TDS=1,263.38 mg/L, based on the summary of groundwater quality analyses in Appendix N of the Class III Permit Application.

Depth and Thickness of Aquifers

In the Dewey-Burdock Project Area, the geologic strata dip gently to the southwest at 2 to 6 degrees; therefore, the depth to the top and bottom of the Inyan Kara Group aquifers varies across the Project Area. Table 1 presents an average depth of the Inyan Kara Group units in the Dewey and the Burdock Areas.

Table 1. Depth below ground surface to the top and bottom of the Inyan Kara Group units

Formation Name	Burdock Area			Dewey Area		
	Top (feet)	Base (feet)	Thickness (feet)	Top (feet)	Base (feet)	Thickness (feet)
Inyan Kara Group	190	425	235	525	760	235
Fall River Formation	190	315	125	525	650	125
Lakota Formation	315	425	110	650	760	110
Fuson Shale	315	355	40	650	690	40
Chilson Sandstone	355	425	70	690	760	70

The vertical extent of the Inyan Kara Group proposed for exemption includes the entire vertical interval which is confined above and below by low permeability shale confining zones as shown in Figure 3.

Areal Extent of Exempted Area

The areal extent of the approved AE is approximately 1,970 acres and includes the areas shown in Figure 2.

The AE area Powertech proposed included the location of commercially producible uranium ore plus a calculated distance of 120 feet beyond the perimeter monitoring well ring for each wellfield. The horizontal extent of the AE area Powertech requested includes all currently identified potential Class III ISR wellfield areas, the perimeter monitoring well rings located 400 feet from the wellfield areas, and an additional area 120 feet outside of the perimeter monitoring well rings. As described in the September 2011 memorandum *Calculation of the Proposed Aquifer Exemption Distance beyond the Monitor Ring: Dewey-Burdock ISR Uranium Project, South Dakota*[1], this area is derived from a science-based

[1] Technical Memorandum to J. Mays, R. Blubaugh - Powertech Uranium, from: Hal Demuth – Petrotek "Calculation of the Proposed Aquifer Exemption Distance beyond the Monitor Ring: Dewey-Burdock ISR Uranium Project, South Dakota" September 12, 2011, included as Appendix M of the Class III Permit Application.

calculation using site-specific properties of the injection interval aquifers and considers the distance that a potential excursion could travel prior to being detected and recovered. The maximum distance that a potential excursion could travel before detection (ΔT) is approximately 47 feet based on the geometry of the monitoring well rings. The estimated distance of potential excursion migration between initial detection and implementation of excursion recovery (Δd) is 24 feet based on a Darcy calculation using a hydraulic gradient representative of a wellfield imbalance that could cause an excursion. The dispersion factor (DF) is estimated as 10% of the total travel distance or 47 feet. The science-based calculation of 118 feet beyond the wellfield perimeter monitoring well ring was rounded up to 120 feet for ease of surveying and plotting on maps. A distance of 120 feet provides a reasonable extension beyond the monitoring ring boundary to enable uranium recovery while remaining protective of the USDWs located outside the exempted portions. For a more detailed explanation of the method Powertech used to determine the horizontal extent of the AE areas, see Appendix M of the Class III Permit Application.

Summary of Proposed AE Boundaries in the 2017 and 2019 Proposed AE RODs

Powertech proposed this AE area before understanding that the Class III Area Permit would require verification that no ISR contaminants will cross the downgradient AE boundary after groundwater restoration and wellfield closure. In comments submitted to EPA on the 2017 draft Class III Area Permit, Powertech reminded EPA that the 2008 Class III Permit Application included a proposed AE boundary located 1,600 feet from potential wellfield patterns of injection and recovery wells and requested that EPA reconsider the larger AE area for each wellfield. EPA had evaluated the 2008 proposed AE boundary along with the 2010 *Updated Technical Report on the Dewey-Burdock Uranium Project Custer and Fall River Counties South Dakota* (Bush, 2010) but was not able to distinguish indicated and measured mineral resources (the demonstrated commercially ore deposits) from the inferred mineral resources (identified but not verified for commercial producibility) on the 2008 proposed aquifer exemption boundary map. EPA was not able to conclude that the 2008 proposed AE boundary was tied to the commercially producible ore areas as discussed in the 2010 updated technical report.

After considering an appropriate distance required for natural attenuation of potentially elevated ISR contaminants within the injection zone aquifer and the fact that the wellfield area may increase after delineation drilling has identified the ore deposit boundaries in better detail, EPA proposed approving up to ¼ mile (1,320 feet) from the currently identified ore deposit boundaries in the second draft AE ROD. The final AE boundary would be determined after delineation drilling identified ore deposit boundary in better detail thus directly tying the final AE boundary to commercially producible ore deposits. However, because this approach delayed EPA approval of the final AE boundary until after delineation drilling, it was later deemed impractical.

Justification for Final AE Boundary

In attempting to determine the extent to which the AE boundary would be expanded by delineation drilling, EPA reviewed the 2020 *Technical Report Preliminary Economic Assessment Dewey-Burdock Uranium ISR Project South Dakota, USA* (Graves and Cutler, 2019, NI 43-10, Effective date: December 3, 2019, Report Date: January 17, 2020). EPA previously reviewed earlier Preliminary Economic Assessment technical reports: Bush, 2010; SRK Consulting, 2012 and Graves and Cutler, 2015. Over time, Powertech's documentation of indicated and measured reserves within the proposed wellfield area

expanded. Based on Figure 16.3 of Graves and Cutler, 2019, EPA concluded that there was adequate documentation of indicated and measured reserves to justify expanding the AE boundary 500 feet from the proposed AE boundary for Burdock Wellfields 1 through 5 and 9. Figure 16.3 shows that ore delineation has expanded in the Dewey Wellfields along the trend of the roll front deposits; however, there was not enough documentation to justify expanding the AE boundary around the entire perimeter of the Dewey Area Wellfields. After reviewing the uncertainties with the amenability of the ISR mining method in Burdock Wellfields 6, 7 and 8, EPA determined it prudent to delay approval of exempting Inyan Kara aquifers in these areas until Powertech submitted the information required in Part II, Section G of the Class III Area Permit.

Confining Zone(s)

Table 2 lists the major confining zones and their minimum and maximum thicknesses at wellfield locations within the Dewey-Burdock Project Area. The thickness values for the upper and lower confining zones for each of the exempted aquifers are based on logs from drillholes located throughout the Dewey-Burdock Project Area. These overlying and underlying confining zones are comprised of shale.

Table 2. Major confining zones

Injection Interval	Confining Zone Formation Name	Minimum Thickness (ft)	Maximum Thickness (ft)
Fall River Sandstone	Upper Confining Zone: Graneros Group	280	550
	Lower Confining Zone: Fuson Shale	20	80
Chilson Sandstone	Upper Confining Zone: Fuson Shale	20	80
	Lower Confining Zone: Morrison Formation	60	140

There are also operational confining units for each wellfield consisting of unnamed shale units separating the Upper and Lower Fall River Formation and the Upper, Middle and Lower Chilson Sandstone, as shown in Figure 3. The wellfield pump tests required under Part II, Sections C, D and F of the Class III Area Permit will verify the ability of these local confining units to direct the injected lixiviant to flow through the ore deposit in the intended injection interval.

Injectate Characteristics

The Class III Area Permit allows the following types of fluids to be injected into the Class III injection wells:

1. During the ISR process, the injection fluid is limited to ISR lixiviant consisting of wellfield groundwater with carbon dioxide and oxygen added.
2. During the groundwater restoration phase, the injectate will be limited to permeate from reverse osmosis (RO) treatment of groundwater extracted from the post-ISR wellfields, clean makeup water or groundwater recirculated within the wellfield.
3. Chemical reductant may be injected for the purposes of aquifer remediation after the Director confirms approval through authorization by rule.

BASIS FOR DECISION

Underground Sources of Drinking Water (USDWs)

UIC regulations found at 40 CFR § 144.3 defines an underground source of drinking water (USDW) as an aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/L total dissolved solids; and

(b) Which is not an exempted aquifer.

The Inyan Kara Group aquifers qualify as USDWs at this project site because the groundwater has a TDS concentration below 10,000 mg/L and contains a sufficient quantity of water to supply a public water system. The TDS concentrations of groundwater samples from different locations within the Fall River Formation and Chilson Sandstone aquifers are included in Appendix N of the Class III Permit Application. The TDS of the Fall River aquifer ranges between 773.85 mg/L-2,250.00 mg/L, with the mean TDS being 1,275.01 mg/L[2]. The TDS of the Chilson Sandstone aquifer of the Inyan Kara Group Lakota Formation ranges between 708.33 mg/L-2,358.33 mg/L with the mean TDS being 1,263.38 mg/L[3]. The TDS content and the capacity to produce a large enough volume of groundwater to supply a public water supply qualify Inyan Kara aquifers as USDWs; therefore, an AE is required to inject under a Class III permit.

Regulatory Criteria under which the exemption is approved

EPA reviewed the information provided by Powertech to demonstrate the proposed AE area meets the regulatory criteria discussed below. Based on the information reviewed, EPA has determined that that the following regulatory criteria are met.

40 CFR § 146.4(a) *It does not currently serve as a source of drinking water*

Powertech reviewed historic records from Silver King Mines, Inc. and the Tennessee Valley Authority (TVA), conducted searches in the South Dakota Water Well database, the South Dakota Water Rights database and the Wyoming State Engineer's database and performed field investigations in order to compile an inventory of wells within approximately 2 km (1.2 miles) of the Dewey-Burdock Project Boundary. Figure 4 shows the locations of the 19 domestic wells identified within 2 km (1.2 miles) of the Project Boundary. A list of the complete well inventory is included in Appendix A of the Class III Permit Application. More detailed information on the well inventory and historic records searched is contained in Appendix B of the Class III Permit Application. EPA determined that 2km (1.2 miles) from the Dewey-Burdock Project Boundary is an adequate distance for the well-search investigation because, as discussed later in greater detail, the capture zone for drinking water wells located outside the Project Boundary, but within the area 2 km (1.2 miles) from the Dewey-Burdock Project Boundary, did not intersect the AE boundary. This distance is greater than the minimum ¼ mile buffer zone from the AE boundary discussed in EPA Guidance #34.

[2] Class III Permit Application Appendix N, p. N-7

[3] Class III Permit Application Appendix N, p. N-11.

Private Drinking Water Wells Inside the AE Boundary

Powertech identified one private drinking water well, well 16, inside the proposed AE boundary that previously used Inyan Kara groundwater for drinking water. Well ID 16 is located within the proposed AE boundary for Burdock Wellfields 6 and 7. Because EPA is not approving exemption of Inyan Kara aquifers for Burdock Wellfields 6 and 7 at this time, well 16 is not an issue for this AE decision. There are no other private drinking water wells inside the AE Boundary at the Dewey-Burdock Project Site.

Nearby Drinking Water Wells Outside the AE Boundary

When considering the capture zone for a well, it is also possible for water within the AE area to serve as a current source of drinking water for wells outside the AE boundary. In this case, EPA looked for wells as far as 2 km (1.2 miles) beyond the Project Boundary. Based on the information available and the calculations performed, this was determined to be an appropriate distance. The technical analysis, described in detail below, demonstrated that water within the AE boundary is not a current source of drinking water for any existing wells.

Including well 16, Figure 4 shows 19 drinking water wells located within 2 km (1.2 miles) of the Dewey-Burdock Project Boundary that are being used, or have been used, for drinking water. Ten of these wells are located outside the Dewey-Burdock Project Boundary. Nine wells (including well 16) are located inside the Project Boundary.

Capture Zone Analysis

A capture zone analysis (CZA) was performed for 11 of the 19 private drinking water wells to evaluate whether any of these existing wells could draw groundwater from within the proposed AE area during the life of the well. CZA, in the context of this document, refers to the determination of the portion of the aquifer from which a well draws groundwater.

Of the ten wells located outside the Project Boundary, six wells are located upgradient or crossgradient relative to the direction of groundwater flow and the Project Boundary. As discussed in the *Technical Memorandum*, no CZA was performed for these six well wells.

No CZA was performed for two of the nine wells inside the Project Boundary. Well 703 is completed in the Unkpapa Sandstone. The Unkpapa Sandstone is not part of the Inyan Kara Group, which contains the aquifers proposed for exemption. The Unkpapa Sandstone is located stratigraphically below and hydrologically separated from the Inyan Kara aquifers by the Morrison Formation lower confining zone. Because this well is not drawing groundwater from the any of the aquifers proposed for exemption, no CZA was needed for this well. Well 16 is located within the AE boundary and is drawing groundwater from the portion of the aquifer proposed for exemption. Because well 16 is already known to draw water from inside the proposed AE boundary, no CZA was performed for this well.

The wells for which a CZA was performed include four wells located outside of and downgradient from the Project Boundary and seven wells located inside the Project Boundary, but outside the proposed AE area.

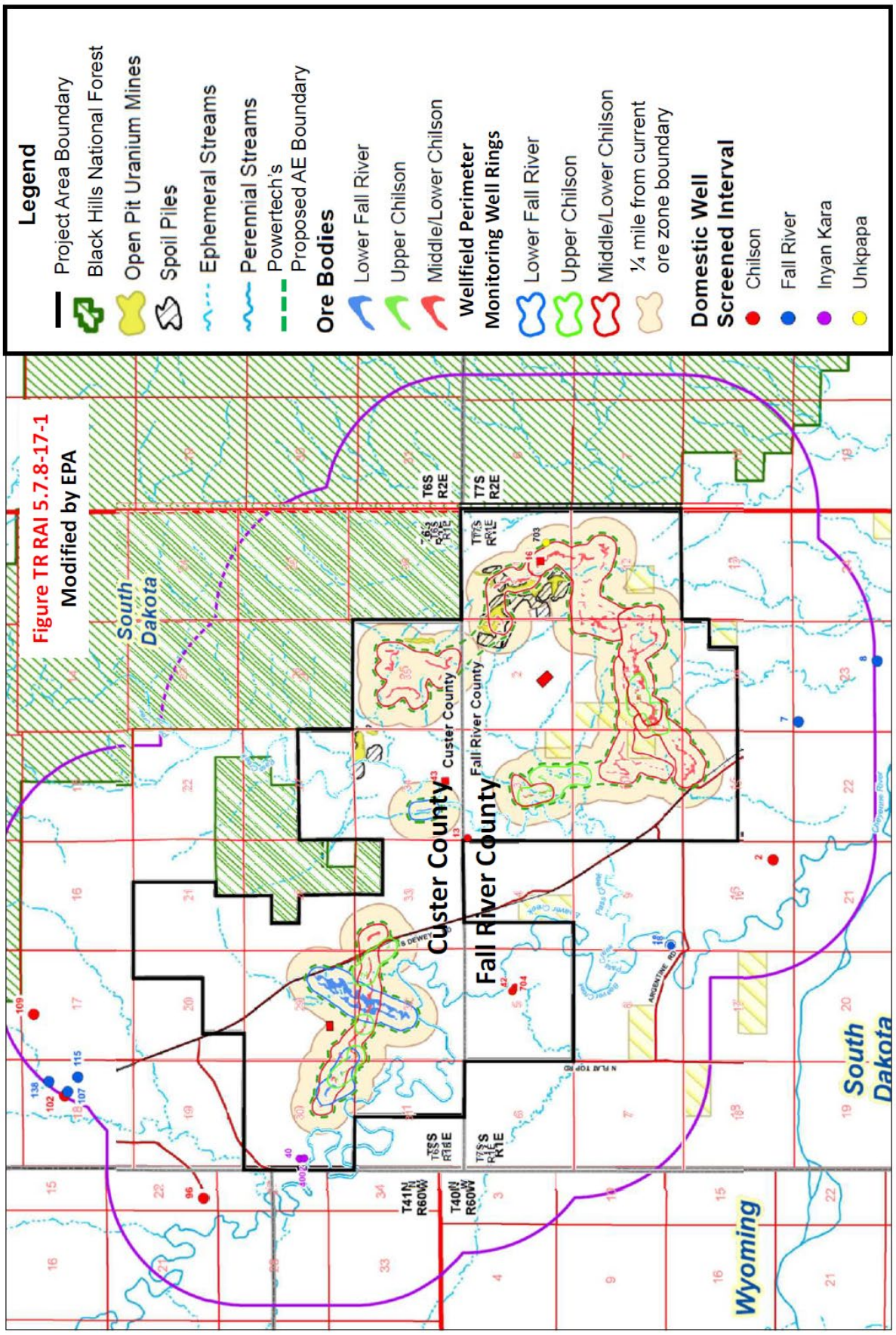


Figure 4. Map of the nineteen private drinking water wells located within approximately 2 km (1.2 miles) of the Dewey-Burdock Project Boundary

Capture Zone Equations

The CZA was based on two equations: one equation calculates the upgradient extent of the Zone of Contribution from a well pumping water from an aquifer with a sloping potentiometric surface and the second equation calculates the width of the capture zone. For a discussion of the first equation, see Section 4.4.3 of EPA *Ground Water and Wellhead Protection Handbook*.[4] For a discussion of the second equation see Figure 4-10 from EPA *Ground Water and Wellhead Protection Handbook.* Table 3 summarizes the information from the capture zone calculations for each well. Appendix A of this document includes the equations and input values for the CZA for each well in Table 3.

In performing the calculations, the following assumptions were made: 1) the drinking water well is constantly pumping and 2) the life of the well from its construction date through 2017 was used for the pumping interval. The assumption that the well is continuously pumping results in a very conservative approach for the areal extent of the capture zone, because this is the maximum amount of time the well could pump and domestic wells are generally not pumped continuously. The capture zone for a well that is continuously pumping is constantly growing larger over time. The capture zone for a well that is pumping intermittently expands while the well is pumping but decreases during the time the well is not pumping and the aquifer potentiometric surface is recovering. As a result, the capture zone for a continuously pumping well is much larger than for a well that is intermittently pumping.

Flow Rates Used in the Capture Zone Equation

EPA evaluated two different scenarios for flow rate in the CZA equations. No records are available on actual domestic use pumping rates for the 11 private wells. Therefore, in the first scenario, EPA used the information available on the 2017 EPA Water Sense website for residential water use (last visited October 19, 2020). The website estimates that the average American family of four uses 400 gallons of water per day. On average, approximately 70% of that water is used indoors, with the bathroom being the largest consumer (a toilet alone can use 27%). The largest family in the Dewey-Burdock area consisted of 10 people, so EPA increased the estimated water usage for each household with a private well to 1,000 gallons per day (gpd), which would be the expected usage for a household consisting of 10 people. An estimated flow of 1,000 gpd is a conservative overestimation for drinking water usage, because it includes 30% expected for outdoor usage and the remaining 70% includes other indoor uses such as laundry, bathing and toilet use.

For the second scenario, EPA used information available in well records or historic TVA records for flow rates from some of the wells that flowed naturally to the ground surface. These flow rates represent the maximum flow volume the well is capable of producing without pumping. For those wells for which no record of flow rate was available, EPA used the maximum value allowed by the South Dakota Department of Environment and Natural Resources for a private well without a water rights permit.[5] This flow rate is 18 gallons per minute (gpm) or 25,920 gpd and represents continuous flow of these wells 24 hours a day. These flow rate values are extreme and greatly overestimate the flow rates expected for a well serving a single-family residence. EPA performed calculations using historic flow rates, if available, 25,920 gpd if no historic flow rate was available and a flow rate of 1,000 gpd for each

[4] Ground Water and Wellhead Protection Handbook, EPA/625/R-94/001, September, 1994

[5] Because none of these wells have a water rights permit, this is the maximum amount they are allowed to pump.

capture zone calculation. Tables A-1 and A-2 in Appendix A of this document show the flow rates used as the input values for each well for which a CZA was performed. The calculations, input values and final results are included in Excel spreadsheets *CaptureZoneCalculations_2017.xlxs* and *CaptureZoneCalculations_1000gpd_2017.xlxs* included in the Administrative Record for the Dewey-Burdock permitting and AE actions.

Wells 40 and 4002 are located so closely together, for the purposes of the CZA these two wells treated as one well, flowing at the combined rate of both wells. Similarly, wells 42 and 704 treated as one well flowing at the combined rate of both wells.

Table 3 shows the results of the capture zone analyses. Calculations using the more realistic, but still conservative flow rate of 1,000 gpd did not result in any capture zones crossing an AE boundary. Under the second scenario, using the historic flow rate of 12 gpm (17,280 gpd) for well 41 (Chilson completion) resulted in a capture zone that extended upgradient 236 ft into the proposed AE area of Dewey wellfields 2 and 4 assuming the well is pumping continuously through 2017. The well has not been used for drinking water since at least 2006 when Powertech performed its well survey.

Three wells, 43, 40 and 4002 are located cross-gradient from the AE area. For these wells, the width of the capture zone was calculated to determine if the capture zone is wide enough to intersect an AE boundary. Because wells 40 and 4002 are located so closely together, they were treated as one well with a flow rate equal to the sum of the flow rates of both wells for the purposes of calculating both the width and upgradient extent of the capture zone. As explained in more detail in Appendix A of this document, the capture zone for wells 40 and 4002 is not wide enough to intersect the AE boundary.

Under the second flow rate scenario, using the State Water Rights Program's maximum well flow rate before a water rights permit is needed of 25,920 gpd for well 43 resulted in a capture zone so wide it encompassed all of Burdock wellfield 10 and extended 1,273 feet into the proposed AE area of Burdock wellfield 8. EPA determined that the flow rates used to calculate the second scenario are a large overestimation of the actual private well flow rates and are not reasonable. Additional calculations were performed for Well 43 to determine the maximum flow rate that would not result in the capture zone crossing an AE boundary. Well 43 could continuously pump up to 4,650 gpd before the width of its capture zone extended crossgradient to reach the AE boundary of Burdock wellfield 10. This pumping rate is greater than 10 times the estimated usage of a family of four discussed above. Because Well 43 is no longer associated with a residence and is not currently being used for drinking water, EPA decided that it was reasonable to conclude the capture zone for Well 43 is not using groundwater inside the AE area.

There are no public water system wells, including municipal wells, utilizing the Inyan Kara aquifers downgradient of the Dewey-Burdock Project Area. The municipal wells owned by the City of Edgemont, which is approximately 13 miles downgradient and to the southeast of the Project Area, are completed in the Madison Formation. Reverse osmosis treatment of Inyan Kara groundwater is necessary to decrease sulfate concentration below the secondary drinking water standards to make it palatable for human consumption. The City of Edgemont chose to drill an additional 2,400 feet to complete wells in the Madison Formation instead of using Inyan Kara groundwater for the public water supply.

Well #	Calculated distances (ft) using well flow rates in Tables 2 and 5		Calculated distances (ft) using 1,000 Gallons per Day		Distance from AE Boundaries (ft)
	Maximum Upgradient Capture Zone Extent	Maximum Width of the Capture Zone	Maximum Upgradient Capture Zone Extent	Maximum Width of the Capture Zone	
2	2,140′	3,655′	1,160′	141′	4,600′ downgradient from B-WF2
7	566′	2,460′	394′	402′	4,750′ crossgradient from B-WF2
8	5,492′	1,244′	5,269′	340′	9,625′ crossgradient from B-WF2
13	959′	299′	914′	207′	1,750′ downgradient from B-WF8
18	1,269′	3,917′	889′	340′	7,880′ downgradient from B-WF4
40	1,340′	2,074′	739′	144′	2,187.5′ crossgradient from D-WF2
41 (Fall River)	1,247′	1,076′	795′	62′	2,750′ downgradient from D-WF 3 3,300′ crossgradient from D-WF1
41 (Chilson)	3,236′	310′	2,924′	18′	3,000′ downgradient from D-WFs 2&4 3,300′ crossgradient from D-WF1
42	2,854′	909′	2,224′	35′	4,800′ downgradient from D-WF4
43	1,147′	4,873′	449′	188′	3,600 crossgradient from B-WF8 875′ crossgradient from B-WF10
704	2,854′	909′	2,224′	35′	4,800′ downgradient from D-WF4
4002	1,340′	2,074′	739′	144′	2,125′ crossgradient from D-WF2

Table 3. Summary of Capture Zone Analysis for the Eleven Drinking Water Wells in and near the Dewey-Burdock Project Site.

Based on the above results, EPA has concluded that the portions of the Inyan Kara aquifers proposed for exemption do not currently serve as a source of drinking water.

Impacts of Expansion of AE Boundary on Private Well Capture Zones

The expansion of the AE boundary for Burdock Wellfields 1 through 5 and 9 does not encroach upon any private well capture zones calculated by the EPA capture zone analysis. If wellfield delineation drilling indicates additional expansion of any of the AE areas is warranted, Powertech must submit an AE request for the additional area. Part II, Section B.1.d.i of the Class III Area Permit requires Powertech to perform a new capture zone analysis for potentially impacted private wells if the expanded AE area encroaches upon a private well capture zone calculated by EPA. Powertech has the option of using a computer flow model with the capability of simulating a more realistic aquifer potentiometric surface impact from intermittent pumping of a private well. This approach would identify a more realistic capture zone that takes into consideration potentiometric surface rebound during the non-pumping phases of private well use. If the AE boundary encroaches on a capture zone after it has been recalculated using the more realistic flow model, Powertech is not authorized to expand the wellfield near the location of the private well capture zone.

40 CFR § 146.4(b)(1)

It cannot now and will not in the future serve as a source of drinking water because:

> *It is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible.*

Powertech provided information to EPA to support the conclusion that the proposed AE area within the Inyan Kara aquifers cannot now and will not in the future serve as a source of drinking water by demonstrating in the Class III permit application for the uranium ISR operation that the portion of the aquifer proposed for exemption contains minerals in a quantity and location that is expected to be commercially producible.

40 CFR § 144.7(c)(1) requires a UIC Class III Permit Application that "necessitates an aquifer exemption under 40 CFR §146.4(b)(1), to furnish the data necessary to demonstrate that the aquifer is expected to be mineral or hydrocarbon producing. Information contained in the mining plan for the proposed project, such as a map and general description of the mining zone, general information on the mineralogy and geochemistry of the mining zone, analysis of the amenability of the mining zone to the proposed mining method, and a time-table of planned development of the mining zone" should be considered by the UIC Director.

Commercial Producibility

The commercial producibility of uranium from the Dewey-Burdock Project has been most recently demonstrated in the 2020 *Technical Report Preliminary Economic Assessment Dewey-Burdock Uranium ISR Project South Dakota, USA*. This document is published on SEDAR (System for Electronic Document Analysis and Retrieval) and is compliant with the National Instrument 43-101 Standards of Disclosure for Mineral Projects (NI 43-101) of the British Columbia Securities Commission. This

document was completed for Powertech by consultants for the purpose of independent confirmation of resource calculations as well as the technical and economic viability of uranium recovery by ISR methods at the Dewey-Burdock Project. The average thickness of the uranium ore deposits targeted by the wellfields is 4.6 feet and the average grade is 0.21% U_3O_8 in the project area. Within the project area, Powertech has identified 14 wellfields that will be designed around economically viable uranium roll-front deposits occurring within the Fall River Formation and the Chilson Sandstone. The information in the report is based on the information from approximately 5,932 drillhole logs in and around the Dewey-Burdock Project Area. The TVA drilled and logged 5,823 exploratory drillholes to define the horizontal and vertical locations of the ore deposits; Powertech drilled and logged an additional 109 exploratory drillholes. The locations of the drillholes are listed in Appendix C of the Class III Permit Application.

Powertech provided cross-sections based on the drillhole logs for each wellfield showing the thickness of the Inyan Kara aquifers, confining zones and overlying formations and the locations of the ore deposits. The drillhole logs are included in the cross-sections. These cross-sections are shown in Plates 6.13 through 6.21 of the UIC Class III Permit Application. Plate 6.12 is the cross-section index showing a map with the locations of the cross-sections through each wellfield.

Demonstration of Amenability of Mining Method

To demonstrate the amenability of the mining zone to the proposed ISR mining method, Powertech performed aquifer pump tests in the Dewey and Burdock areas and referred to pump tests performed by the TVA during the 1980s in the Fall River Formation and the Chilson Sandstone. The Powertech Dewey Area pumping well was completed in the Fall River Formation and the Powertech Burdock Area pumping well was completed in the Chilson Formation. The measurement of water levels in observation wells completed in the pumped aquifers confirmed that during all three pump tests a cone of depression formed in the pumped aquifer. The presence of a cone of depression verifies that hydraulic control of injection interval fluids is able to be maintained in wellfields in both Inyan Kara aquifers and demonstrates the amenability of the proposed ISR mining method. The UIC Class III Area Permit requires Powertech to perform similar pump tests for each wellfield to verify that hydraulic control of injection interval fluids is able to be maintained at each wellfield.

The thickness of the Inyan Kara Group averages approximately 350 feet within the project area. Within the proposed AE boundary, the Inyan Kara Group has the geologic and hydrologic features that make it a suitable host rock for the recovery of uranium using ISR methods as detailed Chapter 2 of the NRC *Generic Environmental Impact Statement for In-Situ Leach Uranium Milling Facilities* (2009): (1) the deposit geometry is generally horizontal and of sufficient size and lateral continuity to economically extract uranium; (2) the sandstone host rock is permeable enough to allow the ISR solutions to access and interact with the uranium mineralization; and (3) the major confining zones (Graneros Group, Fuson Shale and Morrison Formation) plus local confining zones within the Fall River and Chilson aquifers, will prevent ISR solution from migrating vertically into overlying or underlying aquifers.

The potentiometric surface of the Inyan Kara aquifers in the area of Burdock Wellfields 6, 7 and 8 falls below the top of the Fall River Formation and in some areas below the top of the Chilson Sandstone. The aquifers are only partially saturated in these areas, which is not the ideal situation for ISR operations. ISR operations work most efficiently under conditions of full saturation of the injection zone

aquifer. In order for excursion monitoring of overlying aquifers to be effective, these aquifers must also be fully saturated. Because of the uncertainty caused by partially saturated conditions in the areas of Burdock Wellfields 6, 7 and 8, Part II, Section G.3 of Class III Area Permit requires Powertech to perform additional wellfield pump testing, and possibly flow modeling, to demonstrate the amenability of the Inyan Kara aquifers to the ISR process before approving the AE for these areas.

Geochemistry and Mineralogy of the Mining Zone

There are three distinct geochemical zones in the proposed exemption areas of the ore-bearing aquifers within Dewey-Burdock project area: 1) the reduced zone, 2) the oxidized zone and 3) the ore deposit zone.

The reduced zone is located downgradient of the uranium ore deposits and represents the original character of the Inyan Kara sandstones before uranium mineralization occurred. The reduced sandstones are grey in color, pyritic and/or carbonaceous. Organic material consists of carbonized wood fragments and interstitial plant material. Pyrite is abundant within the host sandstones and present as very small cubic crystals or as very fine-grained aggregates. Marcasite is also present as nodular masses in the sandstones. The pyrite contains trace amounts of transition metals (Cu, Ni, Zn, Mo and Se). Plagioclase and potassium feldspar clasts are chemically unaltered. Calcite is sparse, averaging only 0.15% except for localized areas of calcite cementing. A heavy mineral suite (ranging from trace to 3%) of tourmaline, ilmenite, apatite, zircon and garnet is typical of those found in quartz sandstones.

The oxidized zone occurs upgradient of the uranium ore deposit and is characterized by the presence of iron oxides and oxyhydroxides resulting in a brown, pink, orange or red staining of host sandstones. The oxidized zone marks the progression of the downgradient movement of mineralizing solutions through the host sandstones. Within the oxidized zone, pyrite has been altered and is present as hematite or goethite sand grain coatings, clastic particles or as pseudomorphs after the original pyrite crystal shape. Goethite is considered to be metastable and is found near the oxidation/reduction boundary, while the more stable hematite is found greater distances upgradient from the ore deposit zone. The heavy mineral leucoxene – a white titanium oxide – is also present as a pseudomorph of ilmenite. All organic material has been destroyed in the oxidized zone. The oxidizing solutions left dissolution etching on quartz grains and altered the feldspar minerals to clays.

The ore deposit zone is located at the oxidation/reduction boundary where metals were precipitated when mineralizing solutions encountered an abrupt change from oxidizing conditions to reducing conditions as they moved downgradient within the aquifers. Sandstones in this zone are greenish-black, black, or dark grey in color. The primary uranium minerals are uraninite and coffinite, which occur within pore spaces in the sandstone, coat sand grains and form intergrowths with montroseite (VO(OH)) and pyrite. Other vanadium minerals (haggite and doloresite) are found adjacent to the uranium mineralization, extending up to 500 feet into the oxidized portion of the system. Overall, the V-U ratios can be as high as 1.5:1.

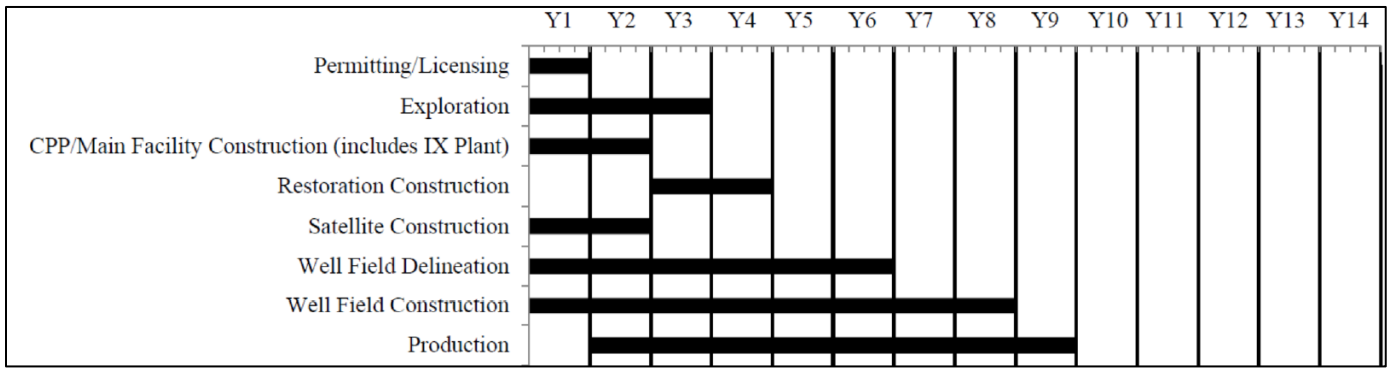
Transition metals removed from the oxidized zone by the mineralizing solutions were precipitated at or adjacent to the oxidation/reduction boundary. Native arsenic and selenium are found adjacent to the uranium, in the upgradient, oxidized boundary of the ore deposit filling pore spaces between quartz grains. Molybdenum occurs as the mineral jordisite adjacent to the uranium on the downgradient,

reduced boundary of the ore deposit. The relatively low concentrations of transition metals indicate their source could have been internal to the Inyan Kara sediments rather than having been introduced from the source of the uranium and vanadium.

Project Timetable

The proposed timetable for project development is shown in Figure 5. Powertech anticipates that the Dewey-Burdock uranium ore deposits will be commercially producible for eight years.

Figure 5. Powertech's Timetable for Project Development



ENSURING PROTECTION OF ADJACENT USDWs

Demonstration that the Injection Zone Fluids Will Remain within the Exempted Portion

EPA guidance #34 states that if the exemption pertains to only a portion of an aquifer, a demonstration must be made that the waste will remain in the exempted portion. Such a demonstration should consider among other factors, the pressure in the injection zone, the waste volume, and injected waste characteristics (i.e., specific gravity, persistence, etc.) in the life of the facility. Given the nature of the ISR operation, waste fluids are not being injected into the exempted portion of the aquifer. The concern in the case of the ISR operation is whether contaminants from ISR activities will cross the AE boundary laterally or migrate vertically into USDWs. A number of factors, including NRC license requirements and Class III Area Permit requirements, led EPA to the conclusion that adjacent USDWs will not be impacted by ISR contaminants crossing the AE boundary laterally or migrating vertically.

The Class III Area Permit includes the following requirements:

- Injection interval confining zones will be evaluated during pre-ISR operation wellfield pump tests for their capacity to contain injection interval fluid vertically within the approved injection interval;
- Powertech must demonstrate the ability of the confining zones to contain injection interval fluids before EPA will issue an authorization to commence injection;
- Powertech must demonstrate the ability of the monitoring network to detect any movement of injection interval fluids out of the approved injection interval before EPA will issue an authorization to commence injection;
- Hydraulic control of the wellfield must be maintained by injecting a smaller volume of lixiviant into the wellfield injection interval than is pumped out. Hydraulic control will be verified by continuous monitoring of injection rate and volume and the measurement of water levels in the

wellfield perimeter monitoring well ring to verify a cone of depression.

- The extensive monitoring well network will verify both lateral and vertical containment of injection interval fluids. If any injection interval fluids begin to migrate out of the approved injection interval, the water level measurements in the monitoring well network will provide early detection to allow Powertech to implement timely corrective response actions to reverse the migration.
- The requirements to demonstrate initial mechanical integrity for all injection, production and monitoring wells and ongoing mechanical integrity tests for injection wells will prevent vertical migration of injection interval fluids through confining zones.
- Part IV, Section D of the Class III Area Permit requires Powertech to develop a wellfield closure plan for each wellfield that includes generating a geochemical model to evaluate the long-term stability of restored ISR contaminant concentrations to ensure that no ISR contaminants cross the AE boundary. As required under Part IV, Section B.5 of the Class III Area Permit, the geochemical model must be calibrated using site-specific groundwater and core data and analytical results from laboratory testing. If the model shows there is a high probability that a restored ISR contaminant concentration will rebound or increase in concentration above the Commission-approved background concentration, Powertech must conduct mitigation measures to stabilize that ISR contaminant.

Vertical confinement

Throughout most of the project area, the Inyan Kara Group is bounded above by shale units of the Graneros Group which serve as the uppermost confining zone for ISR operations. The depth to the top of the Inyan Kara Group ranges from approximately 0 feet where the Fall River Formation crops out in the eastern portion of the Burdock Area to 550 feet below ground surface in the Dewey Area. Analysis of a core sample from the Skull Creek Shale unit of the Graneros Group shows the vertical hydraulic conductivity to be very low: 5.3896E-09 cm/sec, compared with the vertical hydraulic conductivity of the Chilson Sandstone, 1.3474E-03 cm/sec or Fall River Formation sandstone, 4.7659E-04 cm/sec.

As shown in Figure 6, the Graneros Group shales are absent in the eastern portion of the Burdock Area where the Fall River Formation outcrops at the surface in the area shown in blue. Portions of Burdock Wellfields 6, 7 and 8 are located where the Fall River Formation outcrops and the Graneros Group shales are absent. However, these wellfields will be targeting ore in the Middle and Lower Chilson Sandstone shown in the cross-section of Figure 7. No wellfields will be targeting ore in the Fall River Formation where the overlying Graneros Group confining zone is absent. The Fuson Shale, which separates the Chilson Sandstone from the overlying Fall River Formation, acts as the upper confining zone for the Chilson Sandstone as shown in Figure 7.

Figure 7 shows a portion of cross-section B-B' through Burdock wellfield 6. The complete cross-section B-B' can be viewed in Plate 6.14 of the Class III Permit Application. Figure 7 shows the Fuson Shale upper confining zone for the Chilson Sandstone and the shale units separating the Upper, Middle and Lower Chilson. The average thickness of the Fuson Shale is about 50 feet thick in this area. The vertical hydraulic conductivity of the Fuson Shale measured in core sample ranges from 6.1595E-09 to 1.7555E-07 cm/sec.

Geologic cross-sections and logs submitted with the Class III Permit Application indicate that the Fuson

is continuous throughout the Dewey-Burdock Project Area. EPA has reviewed the information that the Powertech provided in the Class III Permit Application and has determined that evidence indicates that except for the northeast corner of Section 1, T7S, R1E where it has been eroded away, the Fuson member of the Lakota formation is a continuous confining zone underlying the Fall River injection interval and overlying the Chilson Sandstone injection interval throughout the Dewey-Burdock Permit Area.

During the Burdock Area aquifer pump tests conducted in the Chilson Sandstone by Powertech and the TVA, there was a response in a monitoring well completed in the overlying Fall River indicating a localized hydraulic connection between the Fall River Formation and the Chilson Sandstone, possibly due to an improperly plugged historic exploration borehole or an old well such as the TVA well that is 10 inches in diameter and screened in both the Chilson and Fall River aquifers. The UIC Class III Area Permit requires thorough investigation of the overlying confining zone for each wellfield before EPA will authorize any injection activities. Section 5.0 of the Fact Sheet for the draft Class III Area Permit discusses the wellfield characterization requirements, including characterization of the confining zones for each wellfield. If a confining zone breach is caused by an improperly plugged historic exploratory drillhole or a well causes a pathway through a confining zone, the UIC Class III Area Permit requires Powertech to take corrective action to prevent the breach from resulting in the vertical migration of injection interval fluids out of the injection interval. The Fact Sheet for the draft Class III Area Permit contains more information about possible breaches in confining zones in Section 4.6 and a discussion of the required corrective action is found in Section 6.0.

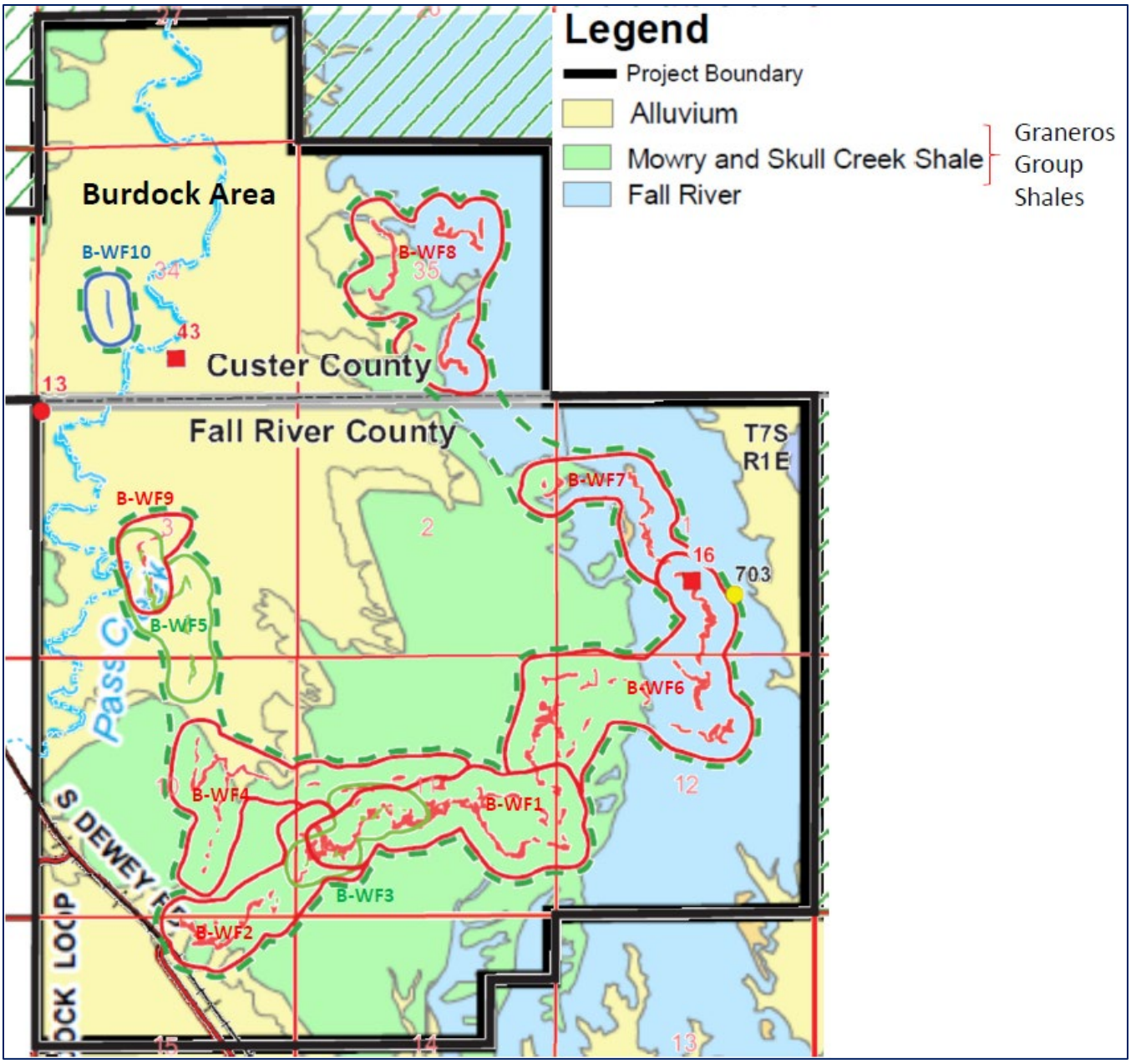


Figure 6. Map Showing Surface Geology of the Burdock Area and Burdock Area Wellfields.

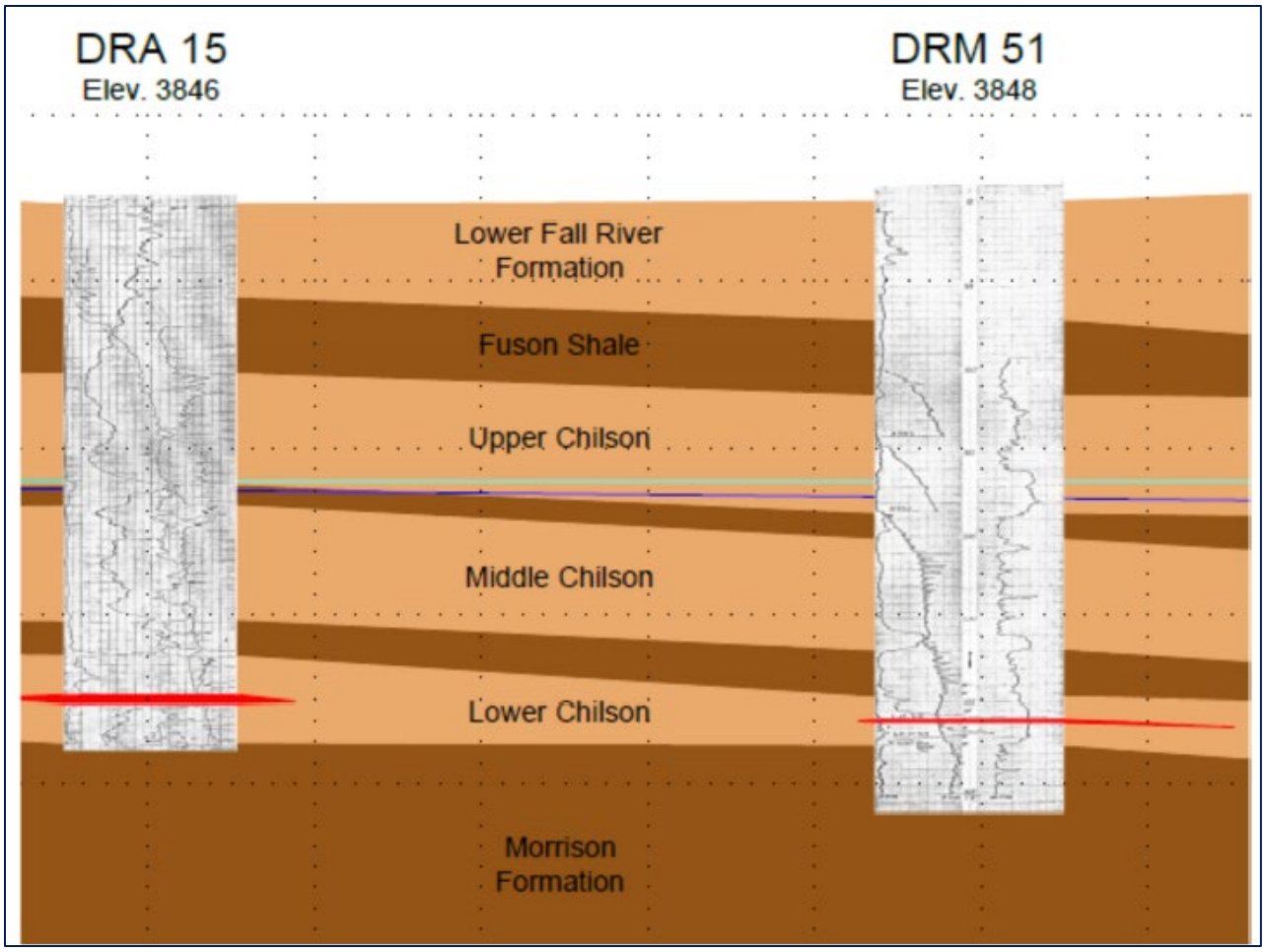


Figure 7. Portion of Cross-Section B-B' from Plate 6.14 of the UIC Class III Permit Application.

The Morrison Formation is the lower confining zone for the Inyan Kara Group. It is a low-permeability shale unit with a thickness of 60 to 140 feet at the Dewey-Burdock Project Site. Analyses of core samples from the Morrison Formation have shown the vertical permeability to be very low and range from 3.9 x 10-9 to 4.2 x 10-8 cm/sec.

To verify that no wellfield fluids migrate vertically out of the approved injection interval, non-injection interval monitoring wells will be completed within each wellfield in the overlying and underlying hydrogeologic units. Because the Morrison Formation is a thick and impermeable confining zone, the Class III Area Permit does not require monitoring of the aquifer underlying the Morrison Formation during wellfield operation or restoration. However, the Class III Area Permit requires at least one observation well below the Morrison Formation to be monitored during wellfield pump tests, to verify the integrity of the Morrison Formation as a confining zone in that area. Analytical results of groundwater samples collected from the overlying and underlying monitoring wells will provide baseline water quality data from which the compliance limits for the overlying and underlying aquifers will be established. These wells will be monitored during wellfield operation, post-ISR groundwater restoration and post-restoration monitoring to detect any potential vertical migration of ISR solutions out of the approved injection interval. EPA may require additional overlying or underlying monitoring wells beyond the minimum density specified in the Class III Area Permit to detect potential vertical excursions in areas where the integrity of a confining zone is in question.

The Class III Area Permit requires Powertech to demonstrate mechanical integrity for all wells installed, including injection, production and monitoring wells, to ensure that the cement-filled annulus between the well casing and drillhole wall does not contain any channels that could potentially allow migration of injection interval fluids out of the injection interval through confining zones.

Lateral Confinement

The Class III Area Permit requires Powertech to demonstrate and maintain hydraulic control of injection interval fluids during the uranium recovery process and post-ISR groundwater restoration. To accomplish this, the wellfield pumping rate must exceed the injection rate resulting in net extraction of injection interval fluids. Continuous monitoring of injection and production flow rates and volume is required for each wellfield to verify that these conditions are being met.

The net extraction of injection interval fluids creates a cone of depression within each wellfield indicating that an inward hydraulic gradient is pulling groundwater into the wellfield. The measurement of water levels in observation wells during the pump tests performed by both the TVA and Powertech demonstrate that a cone of depression formed in the pumped aquifer during the pump tests. The presence of a cone of depression verifies that hydraulic control of injection interval fluids is able to be maintained within Inyan Kara aquifers. The required monitoring of water levels in the wellfield perimeter monitoring well ring verifies that the cone of depression is being maintained during wellfield operations and post-ISR groundwater restoration.

A combination of monitoring and response actions required during the operational, post-ISR groundwater restoration and the post-restoration phases will assure that any effects from the ISR operations will remain within the exempted portion of the aquifers. As discussed in the following section, monitoring wells will be installed in and around each wellfield, up- and down-gradient and in overlying and underlying aquifers, to detect the potential migration of ISR solutions away from the approved injection interval.

Monitoring Requirements

The UIC Class III Area Permit requires Powertech to maintain hydraulic control of injection interval fluids within each wellfield at all times to prevent any horizontal movement of lixiviant out of the wellfield and includes a rigorous monitoring program to verify hydraulic control. For a more detailed discussion of the monitoring requirements, see Section 12 of the Fact Sheet for the Class III Area Permit.

A perimeter monitoring well ring will be completed in the ore zone injection interval aquifer around each wellfield. These wells will be used to verify the existence of the cone of depression through monitoring the water level in each well. A rise in water level detected in any well will signal an incipient loss of hydraulic control allowing it to be corrected before any lixiviant actually moves out of the approved injection interval. Groundwater sampling at the perimeter monitoring well ring will detect any potential horizontal migration of fluid outside the wellfield. Perimeter monitoring wells will be located no farther than 400 feet from the wellfield, evenly spaced with a maximum spacing of either 400 feet or a spacing that will ensure a 70 degree angle between adjacent perimeter monitoring wells and the nearest injection well as illustrated in Figure 8.

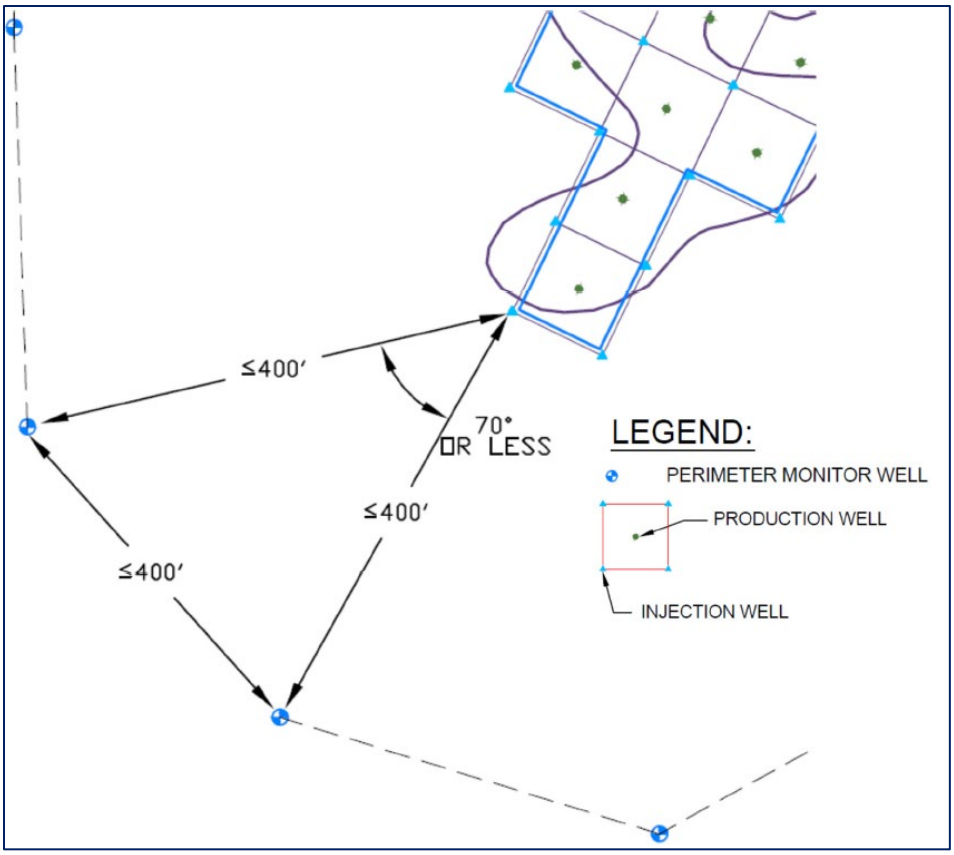


Figure 8. Spacing between Perimeter Monitoring Wells Will Be No Greater than 400 Feet or Close Enough to Ensure a 70º Angle between Adjacent Perimeter Monitoring Wells and the Nearest Injection Well

Non-injection zone monitoring wells will be completed in aquifers overlying the injection interval and, in some cases, below the injection interval. Groundwater sampling at these wells will detect any potential vertical migration of fluid outside the wellfield. These wells will be located every 4 acres in the first overlying aquifer and every 8 acres in other overlying aquifers. If the Morrison Formation is the lower confining zone, the Class III Area Permit does not require any monitoring wells in the underlying aquifer because Powertech has demonstrated the Morrison confining zone is thick and continuous across the Project Area. Wellfield aquifer pump tests will confirm the integrity of the Morrison Formation as a confining zone. In other underlying aquifers, monitoring wells will be placed every 4 acres.

Operational groundwater monitoring will be conducted to detect potential changes in groundwater quality in and around the project area as a result of ISR operations. The operational groundwater monitoring program will include domestic wells, stock wells and wells located hydrologically upgradient and downgradient of ISR operations. Wells to be included in the operational monitoring program include domestic wells within 2 km (1.2 miles) of the wellfield areas, stock wells within the Project Area, and additional monitoring wells within the project area in the alluvial, Fall River, Chilson and Unkpapa aquifers.

Monitoring within the wellfield during groundwater restoration will be conducted in accordance with the NRC license, which requires Powertech to conduct groundwater restoration after uranium recovery has been completed in a wellfield. Groundwater restoration must continue until ISR contaminant concentrations are at or below Commission-approved background or drinking water standards. If these

concentrations cannot be achieved, then Powertech will submit to NRC an application for approval of an alternate concentration limit (ACL), which is an amendment to the license. NRC will not approve an ACL unless Powertech demonstrates the ACL is protective of human health and the environment.

The UIC Class III Area Permit does not have any groundwater restoration standards within the wellfield. Instead, the UIC Class III Area Permit requires the Permittee to demonstrate through geochemical modeling as part of a Wellfield Closure Plan that ISR contaminants will not cross the downgradient aquifer exemption boundary into the USDW. The UIC Class III Area Permit has groundwater permit limits for ISR contaminants that must be met at the AE boundary.

A post-restoration stability monitoring period will be conducted in accordance with the NRC license, After groundwater restoration is completed for a wellfield, Powertech must conduct post-restoration stability monitoring to determine that restored concentrations of ISR contaminants are chemically stable and will not rebound or increase in concentration over time. The NRC license requires that stability monitoring be conducted until the data show that the ISR contaminant concentrations for the most recent four consecutive quarters indicate no statistically significant increasing trend. If a constituent does not meet the stability criteria, Powertech must take appropriate actions to remedy the situation. Potential actions may include extending the stability monitoring period or returning the wellfield to a previous phase of active restoration until Powertech can demonstrate the chemical instability issue is resolved. If the analytical results from the stability period continue to meet the NRC license Commission-approved background, MCLs or ACLs and meet the stability criteria, Powertech will submit supporting documentation to NRC showing that the restoration parameters have remained at or below the restoration standards and request that the wellfield be declared restored.

The UIC Class III Area Permit contains requirements for monitoring during the post-restoration groundwater stabilization phase within a wellfield. The UIC Class III Area Permit require calibration of the wellfield geochemical model to groundwater and core data after this post-restoration groundwater stabilization phase has been completed.

OTHER CONSIDERATIONS

EPA evaluated the groundwater quality of the Inyan Kara aquifers within the area proposed for exemption and the likelihood that Inyan Kara groundwater within the AE boundary would be used for drinking water at some time in the future. Analytical results from the Inyan Kara aquifer groundwater samples are included in Appendices N and O of the Class III Permit Application. As stated earlier, the TDS of the Fall River Formation of the Inyan Kara Group ranges between 773.85 mg/L-2,250.00 mg/L, with a mean TDS of 1,275.01 mg/L; the TDS of the Chilson Sandstone unit of the Lakota Formation of the Inyan Kara Group ranges between 708.33 mg/L-2,358.33 mg/L, with a mean TDS of 1,263.38 mg/L. Inyan Kara groundwater requires treatment by reverse osmosis to decrease TDS, iron, manganese and sulfate concentration below the secondary drinking water standards before is it palatable for human consumption. In addition to these taste and odor concerns, Inyan Kara wells completed within the ore zone also have radium and gross alpha concentrations above MCLs and radon concentrations are high.

The water for the City of Edgemont, which is approximately 13 miles southeast of the Project Area, is supplied from municipal wells completed in the Madison Formation. Reverse osmosis is an expensive option for a public water system to use. Reverse osmosis treatment also generates a large volume of

concentrated reject brine that would require disposal. The City of Edgemont chose to drill an additional 2,400 feet to complete wells in the Madison Formation instead of using Inyan Kara groundwater for the public water supply.

The land use in the Dewey-Burdock Project Area is mainly grazing for cattle ranches. It is unlikely that the population will increase in that area to a size that would support a public water system. According to www.census.com, the population of Edgemont has decreased since 2000: in the 2000 census, the population was 867; in 2010, it was 774; in 2015, the estimated population was 739. Based on this information, it is unlikely that the Inyan Kara groundwater within the AE boundary would be used in the future to supply drinking water.

CONCLUSION AND DECISION

Based on review of the information Powertech provided, EPA finds that exemption criteria 40 CFR § 146.4(a) and 146.4(b)(1) have been met. EPA approves the AE request as a minor/non-substantial program revision for the AE area shown in Figure 2.

_____ 11/24/2020

Darcy O'Connor, Director
Water Division

Date

Appendix A
CZA Information

Equation number 4-7 in Section 4.4.3 Time of Travel with Sloping Regional Potentiometric Surface in the EPA *Ground Water and Wellhead Protection Handbook* was used to determine the upgradient extent of the capture zone.

Handbook **EPA/625/R-94/001**
September 1994

Ground Water and Wellhead Protection

4.4.3 TOT With Sloping Regional Potentiometric Surface

$$t_x = n/Ki\,[r_x - (Q/2\pi Kbi)\ln\{1 + (2\pi Kbi/Q)r_x\}] \quad (4\text{-}7)$$

where
t_x = travel time from point x to a pumping well
n = porosity
r_x = distance over which ground water travels in T_x, r_x is positive (+) if the point is upgradient, and negative (–) is downgradient

Q = discharge
K = hydraulic conductivity
b = aquifer thickness
I = hydraulic gradient

Transmissivity (T) was used in the equation instead of hydraulic conductivity (K) and aquifer thickness (b).
Transmissivity T=Kb

Table A-1 shows the information on age and historic flow rate information for each well. As described in the ROD, if no information on the construction date of the well was available in historic records, the age of the oldest well was used. The older the well, the larger the capture zone. The two scenarios for flow rate are described earlier in this document.

Table A-2 shows all the values used for all variables in the capture zone equation. Table 3 shows the calculated upgradient extent of each capture zone using both scenarios for flow rate. Table 3 also shows the distance each well is located downgradient from an AE boundary. So as not to call into question the exact downgradient flow direction upgradient from each drinking water well, the distance to the closest AE boundary was used for comparison to the calculated extent of the capture zone included in Table 3. As discussed earlier, because wells 40 and 4002 are located so closely together, they were treated as one well with a flow rate equal to the sum of the flow rates of both wells for the purposes of calculating upgradient extent and the width of the capture zone. Similarly, because wells 42 and 704 are located so closely together, they were treated as one well with a flow rate equal to the sum of the flow rates of both wells for the purposes of calculating upgradient extent and the width of the capture zone.

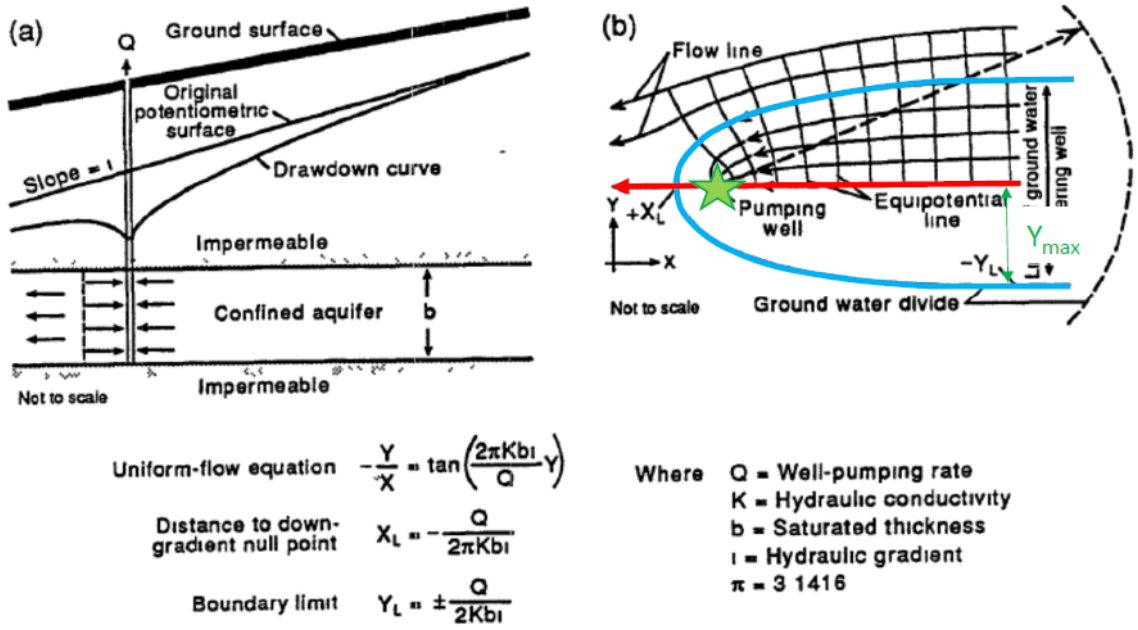
Well ID#	Sec,Township Range	Screened Interval & Project Site Area	Distance & Direction from Aquifer Exemption Boundary	Year Constructed/# Years & Days of Operation to 2017	Historic Values for Flow rate gpm
2	SESE Sec 16 T7S R1E	Chilson Burdock	4,600' downgradient from B-WF2	1930s, Use 1930 32,142 days	30 gpm which is greater than the SEO allows without water rights permit Use 18 gpm / 25,920 gpd
7	NWNW Sec 23 7S 1E	Fall River Burdock	4,750' crossgradient from B-WF2	Late 1950s, Use 1958 21,915 days	4.25 gpm 6,120 gpd
8	SWSE Sec 23 23 7S 1E	Fall River Burdock	9,625' crossgradient from B-WF2	Well repair form 1951. Casing had corroded away. Assume original well drilled in 1930 32,142 days	2.5 gpm 3,600 gpd
13	NWNW Sec 3 T7S R1E	Chilson Burdock	1,750' downgradient from B-WF10	1950s, Use 1950 24,837 days	Notice of well construction says well flows at 1 gpm, 1,440 gpd
18	SWSW Sec 9 T7S R1E	Fall River Burdock	7,880' downgradient from B-WF4	Late 1920s to early 1930s Use 1930 32,142 days	8 gpm 11,520 gpd
40	SWNW Sec 30 T6S R1E	Inyan Kara Dewey	2,187.5' crossgradient from D-WF2	1969 17,897.25 days	2 gpm 2,880 gpd
41	SWNE Sec 31 T6S R1E	Fall River Dewey	2,750' downgradient From D-WF3 3,300' crossgradient from D-WF1	No information Use 1930; 32,142 days	12 gpm 17,280 gpd
41	SWNE Sec 31 T6S R1E	Chilson Dewey	3,000' downgradient From D-WFs 2&4 3,300' crossgradient from D-WF1	No information Use 1930; 32,142 days	12 gpm 17,280 gpd
42	SWNE Sec 5 T7S 1E	Chilson Dewey	4,800' downgradient From D-WF4	1949 25,202.25 days	Flows 30 gpm, Use 18 gpm 25,920 gpd
43	SWSE Sec 34 T6S R1E	Chilson Burdock	3,600' crossgradient from B-WF8 875' crossgradient from B-WF10	No information Use 1930; 32,142 days	No info Use 18 gpm 25,920 gpd
704	SWNE Sec 5 T7S 1E	Chilson Dewey	4,800' downgradient From D-WF4	2008 3,652.5 days	No info Use 18 gpm 25,920 gpd
4002	NWSW Sec 30 T6S R1E	Inyan Kara Dewey	2,125' crossgradient from D-WF2	1940s Use 1940 28,489.5 days	No info Use 18 gpm 25,920 gpd

Table A-1. Well Location Information and the Values for Well Age and Flow Rate Used in the Capture Zone Equation.

Well ID#	Sec, Township Range	Screened Interval	Transmissivity (T) (ft^2/day)	Porosity (n) (%)	Hydraulic Gradient (i) (ft/ft)	Aquifer Thickness b (ft)	Age of well at end of 2017 (days)	Flow Rate (gpd)
2	SESE 16 T7S R1E	Chilson Burdock	150 & 190	0.296 & 0.319	0.00316	63	32,142	25,920 & 1,000
7	NWNW Sec 23 7S 1E	Fall River Burdock	54 & 255	0.29	0.00308	186	21,915	6,120 & 1,000
8	SWSE Sec 23 23 7S 1E	Fall River Burdock	54 & 255	0.29	0.00364	20	32,142	3,600 & 1,000
13	NWNW 3 T7S R1E	Chilson Burdock	150 & 190	0.296 & 0.319	0.00215	45	24,837	1,440 & 1,000
18	SWSW 9 T7S R1E	Fall River Burdock	54 & 255	0.29	0.00364	128	32,142	11,520 & 1,000
40	SWNW 30 T6S R1E	Inyan Kara Dewey	255	0.29	0.00364	150	17,897.25	2,880 & 1,000
41	SWNE Sec 31 T6S R1E	Fall River Dewey	255	0.29	0.00421	165	32,142	17,280 & 1,000
41	SWNE Sec 31 T6S R1E	Chilson Dewey	590	0.296 & 0.319	0.00631	140	32,142	17,280 & 1,000
42	SWNE 5 7S 1E	Chilson Dewey	590	0.296 & 0.319	0.00646	150	25,202.25	25,920 & 1,000
43	SWSE 34 T6S R1E	Chilson Burdock	150 & 190	0.296 & 0.319	0.00237	145	32,142	25,920 & 1,000
704	SWNE 5 7S 1E	Chilson Dewey	590	0.296 & 0.319	0.00646	150	3,652.50	25,920 & 1,000
4002	NWSW 30 T6S R1E	Inyan Kara Dewey	255	0.29	0.00364	150	28,489.5	25,920 & 1,000

Table A-2. The Input Values for All Variables in the Capture Zone Equation, Distance and Direction Each Well Is Located from nearest AE Boundary and the Calculated Extent of the Capture Zone.

To calculate the capture zone width, the boundary limit equation was used as shown below in Figure A-1 which is Figure 4-10 from the EPA *Ground Water and Wellhead Protection Handbook*. The groundwater divide shown as the blue line is the outer boundary of the capture zone for the well represented by the green star in the figure below. All groundwater outside the blue groundwater divide will flow past the well. All groundwater inside the blue groundwater divide will flow to the well. The groundwater divide is calculated using the uniform-flow equation shown in Figure 4-10. The boundary limit equation calculates the maximum width measured from the red capture zone centerline attained by groundwater divide. This maximum width is called Y_{max}. For the wells located cross-gradient from an AE boundary, wells 40, 4002 and 43, $Y_{max,}$ must be calculated for the capture zone. For wells 40 and 4002, Y_{max} was smaller than the nearest AE boundary. As discussed earlier, because wells 40 and 4002 are located so closely together, Y_{max} was calculated using the combined flow rate of the two wells.



Transmissivity (T) was used in the equation instead of hydraulic conductivity (K) and aquifer thickness (b). Transmissivity T=Kb

Figure A-1. Illustration of the Boundary Limit Equation used to Calculate the Maximum Width of the Well Capture Zone.

More detailed information on the CZA is provided in the *Technical Memorandum Documenting the Capture Zone Analysis for Eleven Private Drinking Water Wells in and near the Dewey-Burdock Uranium In-Situ Recovery Project Site Northwest of Edgemont, South Dakota* included in the Administrative Record for the Dewey-Burdock permitting and AE actions.

EXHIBIT 2

United States Environmental Protection Agency Region 8 Underground Injection Control Program final underground injection control (UIC) permits for UIC Permit Nos. SD31231-00000 and SD52173-00000, issued following the Environmental Appeals Board's (EAB) September 12, 2025 Order Denying Review

REGION 8
DENVER, CO 80202

Ref: 8WD-SDU

SENT VIA EMAIL
DIGITAL READ RECEIPT REQUESTED

Mr. Jon Winter
Permitting and Regulatory Affairs Manager
Powertech (USA) Inc.
jwinter@encoreuranium.com

Dear Mr. Winter:

In accordance with 40 C.F.R. § 124.19(l)(2)(i), the Environmental Protection Agency Region 8 (Region) is issuing final underground injection control (UIC) permits for UIC Permit Nos. SD31231-00000 and SD52173-00000, following the Environmental Appeals Board's (EAB) September 12, 2025 Order Denying Review. The Region originally reissued the permits on March 14, 2025, and a petition was filed with the EAB on April 11, 2025, staying the effective date until after an EAB decision and final agency action (See 40 C.F.R. § 124.15(b)(2)).

The effective date of the final permits will be 30 days after this service of notice of the Region's decision, or October 25, 2025. The Region's reissuance of the permits is a final disposition for judicial review, see 40 C.F.R. § 124.19(l)(2)(iii). Pursuant to the Safe Drinking Water Act, 42 U.S.C. § 300j-7, a petition for judicial review of the permits may be filed only within the 45-day period beginning on the date of the final agency action, which is the date of issuance of the reissued permits. Under 40 C.F.R. § 23.7, the date of issuance of the permits is two weeks after signature. Please find the final permits enclosed.

If you have any questions, please contact Rick Arnold of my staff at (303) 312-6788 or arnold.rick@epa.gov.

Sincerely,

Sarah Bahrman, Acting Director
Water Division

Enclosures

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
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DENVER, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

UNDERGROUND INJECTION CONTROL

Final

CLASS III AREA PERMIT

Date: September 2025

Area Permit No. SD31231-00000

Class III Injection Well Area Permit
Dewey Burdock Uranium In-Situ Recovery Project
Custer and Fall River Counties, South Dakota

Issued To

Powertech (USA) Inc.
P.O. Box 448
Edgemont, South Dakota 57735

TABLE OF CONTENTS

Contents

PART I. EFFECT OF PERMIT

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this Area Permit,

Powertech (USA) Inc.
P.O. Box 448
Edgemont, South Dakota 57735

is hereby referred to as the "Permittee."

Because this permit authorizes more than one injection well, it is an Area Permit and subject to the requirements found at 40 CFR § 144.33. The Permittee is allowed to engage in underground injection in accordance with the conditions of this Area Permit. The Permittee must not construct, operate, maintain, convert, plug, abandon or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit, or by rule, is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable State or local laws or regulations.

Issuance of this Area Permit authorizes the construction and operation of the Class III uranium in-situ recovery (ISR) injection wells in the wellfields listed in Table 1 within the Permit Area described below according to the conditions set in this Area Permit.

A. Class III Permit Area Boundary

The Class III injection wells must be located within the Permit Area. As shown in Figure 1, the Class III Permit Area is located in Custer and Fall River Counties, South Dakota. The area included within the Class III Permit Boundary encompasses the portions of Sections 20, 21, 27, 28, 29, 30, 31, 32, 33, 34 and 35 of Township 6 South, Range 1 East in Custer County, South Dakota. The Permit Area also includes the portions of Sections 1, 2, 3, 4, 5, 10, 11, 12, 14 and 15 in Township 7 South, Range 1 East in Fall River County, South Dakota. Figure 2a shows the Dewey Area ore deposit and wellfield locations in Sections 29, 30, 31, 32 and 33 of Township 6 South, Range 1 East. Figure 2b shows the Burdock Area ore deposit and wellfield locations in Sections 34 and 35 of Township 6 South, Range 1 East and Sections 1, 2, 3, 10, 11, 12, 14 and 15 Township 7 South, Range 1 East.

B. Well Locations

This Area Permit authorizes the construction and operation of Class III injection wells in the 14 wellfields located within the Permit Area described above according to the conditions set in this Area Permit. The approximate locations of these fourteen wells fields are listed in Table 1.

Table 1. Wellfields Proposed under the Class III Area Permit

Wellfield Permit Number	Wellfield Name	Section/Township/Range
SD31231-09459	Burdock Wellfield 1	Sections 11 and 12 T7S R1E
SD31231-09460	Burdock Wellfield 2	Sections 10, 11, 14 and 15 T7S R1E
SD31231-09461	Burdock Wellfield 3	Sections 10 and 11 T7S R1E
SD31231-09462	Burdock Wellfield 4	Sections 10 and 11 T7S R1E
SD31231-09463	Burdock Wellfield 5	Sections 3 and 10 T7S R1E
SD31231-09464	Burdock Wellfield 6	Sections 1, 2, 11 and 12 T7S R1E
SD31231-09465	Burdock Wellfield 7	Sections 1 and 2 T7S R1E
SD31231-09466	Burdock Wellfield 8	Section 35 T6S R1E
SD31231-09467	Burdock Wellfield 9	Section 3 T7S R1E
SD31231-09470	Burdock Wellfield 10	Section 34 T6S R1E
SD31231-08351	Dewey Wellfield 1	Sections 29 and 32 T6S R1E
SD31231-09471	Dewey Wellfield 2	Sections 29, 30, 31, 32 and 33 T6S R1E
SD31231-09472	Dewey Wellfield 3	Sections 29, 30, 31 and 32 T6S R1E
SD31231-09473	Dewey Wellfield 4	Sections 29, 30, 31, 32 and 33 T6S R1E

C. Area Permit Information

Permit requirements herein are based on regulations found in 40 CFR parts 124, 144, 146, and 147, which are in effect on the Effective Date of this Permit. The UIC regulations specific to South Dakota are found at 40 CFR part 147, subpart QQ.

This Area Permit is based on representations made by the applicant and on other information contained in the Administrative Record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Area Permit and/or formal enforcement action.

Effective date: 30 days after signature date

_____

Sarah Bahrman, Acting Director*
Water Division

The Area Permit will remain in effect for the life of the facility. The Director must review this Area Permit at least once every 5 years to determine whether it should be modified, revoked and reissued, terminated, or a minor modification made as provided in §§ 144.39, 144.40, and 144.41. This Area Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to the State of South Dakota. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions must be directed to the State Program Director or designee.

*NOTE: Throughout this Permit the term "Director" refers to either the Director of the Water Division (or authorized representative) or the Chief of the Water Enforcement Branch of the Enforcement and Compliance Assurance Division (or authorized representative).

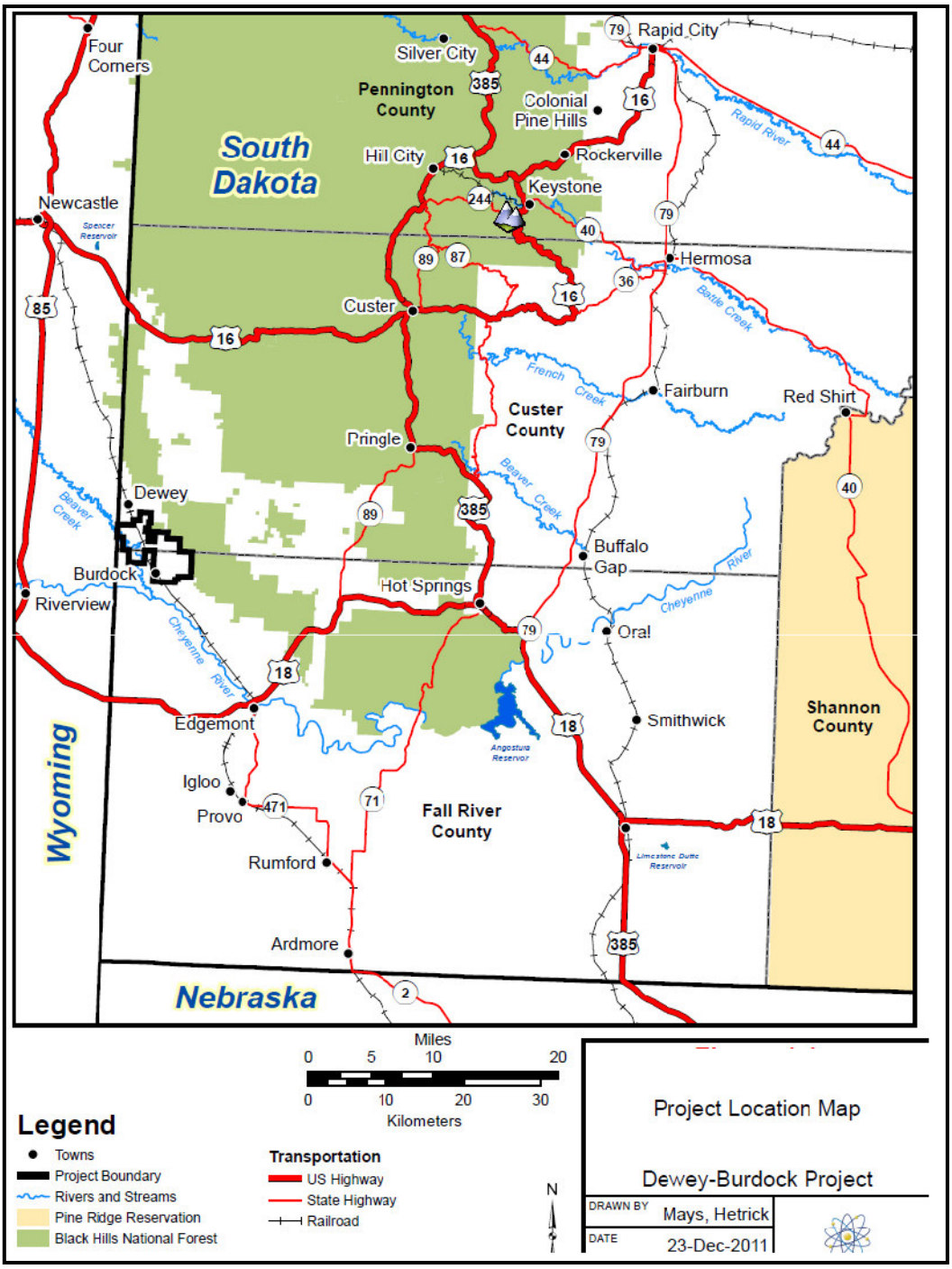


Figure 1. Dewey Burdock Project Location

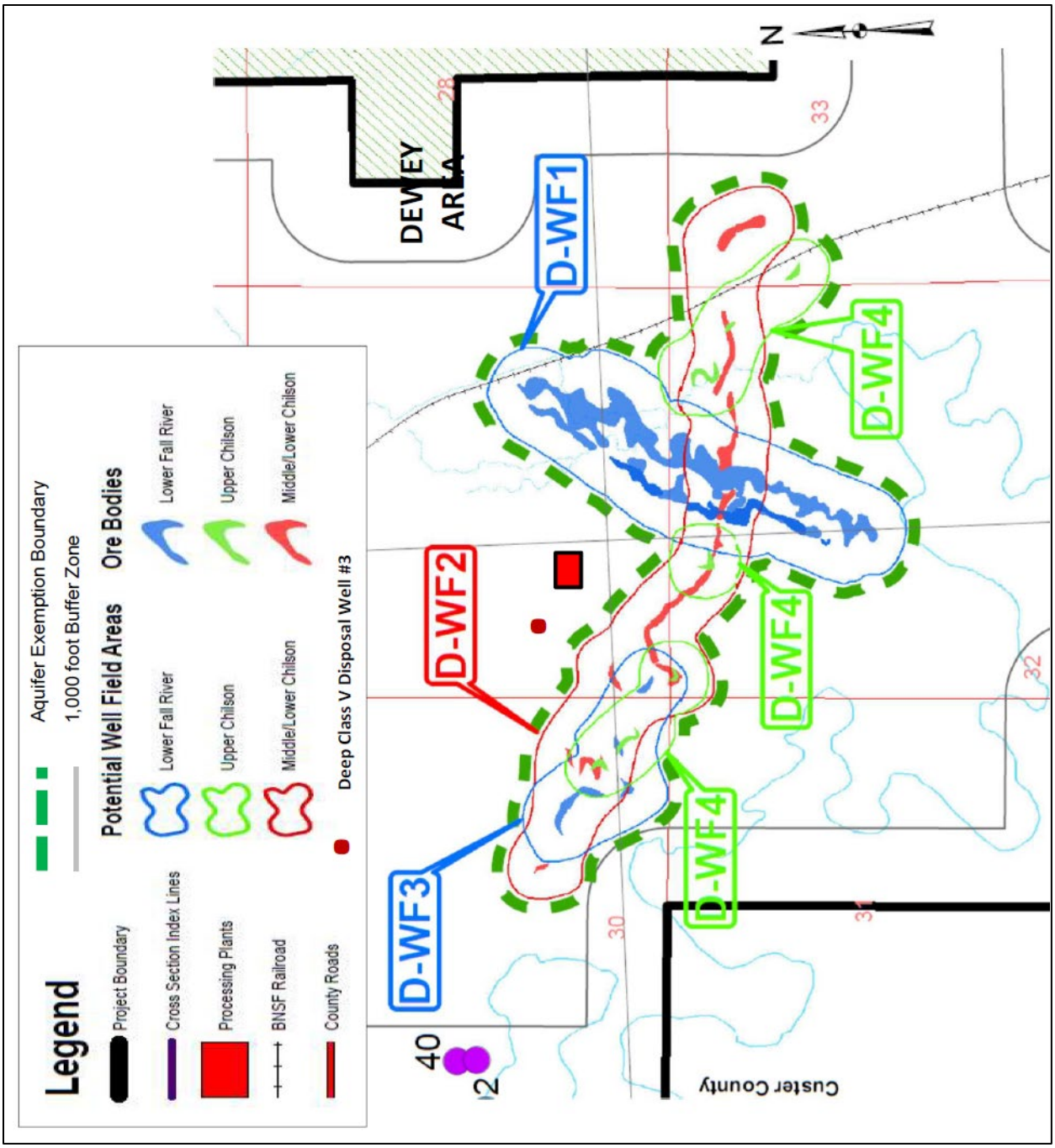


Figure 2a. Locations of the Proposed ISR Wellfields in the Dewey Area.

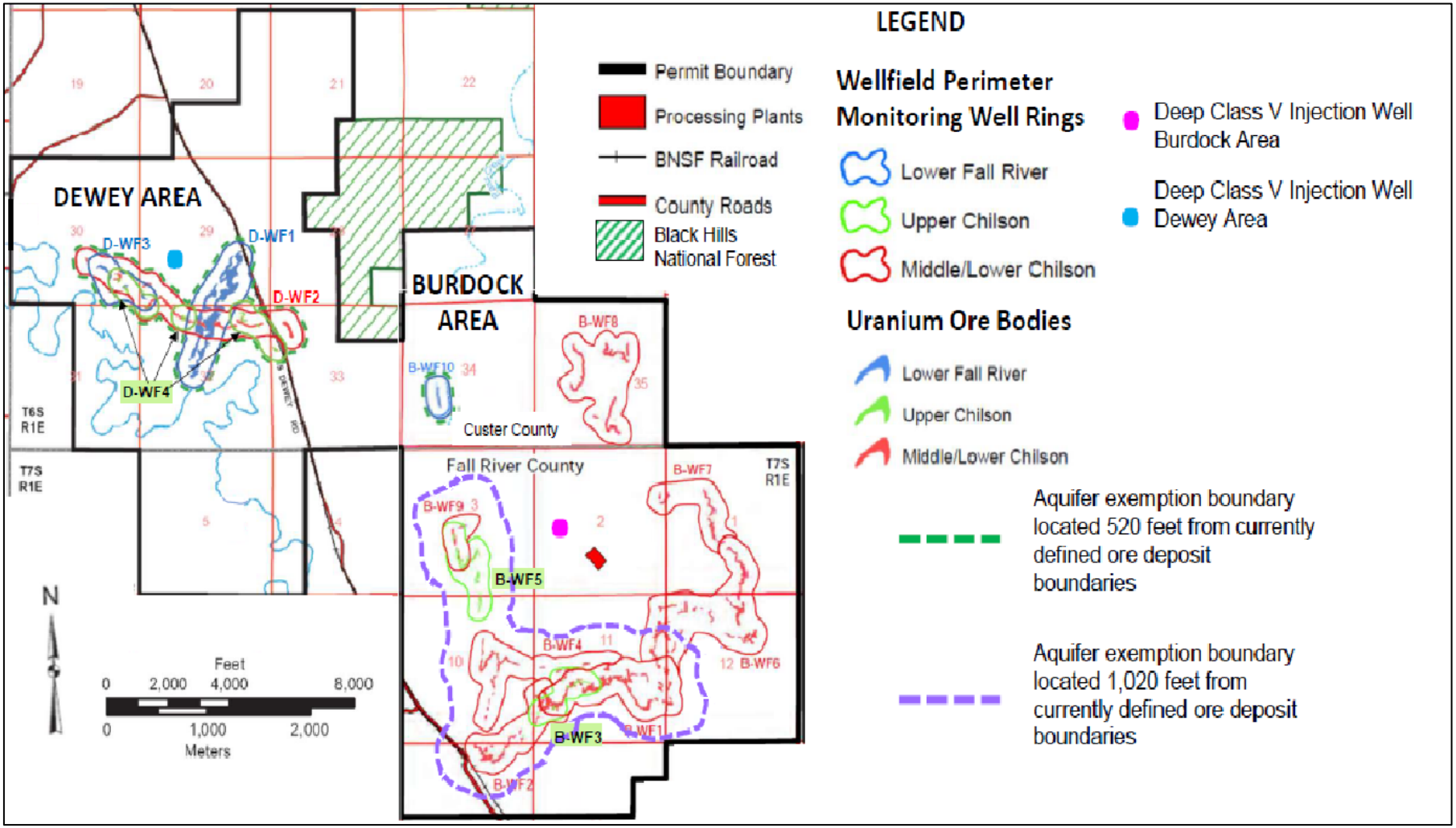


Figure 2b. Locations of the Proposed ISR Wellfields in the Burdock Area.

PART II. WELLFIELD DELINEATION AND PUMP TESTING REQUIREMENTS; AUTHORIZATION TO COMMENCE INJECTION

In order to obtain an Authorization to Commence Injection into wellfield injection wells, wellfield delineation drilling, drillhole logging, and wellfield testing must be performed as described below. A descriptive report interpreting the results of logs and tests must be prepared by a knowledgeable log analyst and submitted to the Director as part of the Injection Authorization Data Package Report described in Section H of this Part.

A. Wellfield Location Restrictions

All wellfields and perimeter monitoring wells must be located within the Permit Area boundary described in Part I. No Class III injection or production wells must be located within the buffer zone located 1,000 feet from the Permit Area boundary in order to establish an operational buffer between the wellfields and the Permit Area boundary. The 1,000-foot buffer zone boundary is shown in Figures 2a and 2b. However, perimeter monitoring wells may be located within the 1,000-foot buffer zone.

B. Drilling and Logging of Wellfield Delineation Drillholes and Pump Testing Wells

The Permittee must conduct the following drilling and logging operations as described below to identify:

(1) the top and bottom depths of the upper and lower confining zones across the wellfield;
(2) the top and bottom depths of the injection interval across the wellfield;
(3) the horizontal extent of injection interval across the wellfield; and
(4) the top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.

1. Wellfield Delineation Drilling

a. The Permittee must conduct delineation drilling to delineate the vertical and horizontal extent of the ore deposits targeted for ISR operations within the wellfield and develop a more detailed conceptual hydrogeologic model for wellfield design including:
   i. the horizontal and vertical extent of the proposed injection intervals based on ore deposit locations;
   ii. the presence and thickness of overlying confining zones; and
   iii. the presence and thickness of overlying aquifer units requiring non-injection interval monitoring wells.

b. So as not to compromise the integrity of the Morrison Formation lower confining zone of the Inyan Kara Group, the only delineation drillholes required through and below the Morrison Formation are those for the two new observation wells described in Section C.2.d and Section D.4.c.ii of this Part.

c. If the lower confining zone for the target injection interval is <u>not</u> the Morrison Formation, then delineation drillholes must penetrate below the proposed injection interval through the first underlying aquifer unit to evaluate:
   i. the thickness of the confining zone underlying the target injection interval; and
   ii. the thickness of the first underlying aquifer unit requiring non-injection interval monitoring wells.

d. If the horizontal extent of any uranium ore deposit as determined by wellfield delineation drilling results indicates expansion of the aquifer exemption boundary is needed, beyond the locations shown in Figures 2a and 2b, the Permittee must submit a new aquifer exemption application to the Director for review and approval.

i. If the expanded aquifer exemption boundary encroaches on the capture zone of a private well as calculated by the EPA in the aquifer exemption Record of Decision, the Permittee must perform a new capture zone analysis for potentially impacted private wells using a computer flow model with the capability of simulating the effect of intermittent pumping on the aquifer potentiometric surface.

ii. If the updated capture zone analyses demonstrate the aquifer exemption boundary would encroach on the capture zone of a private well, the Director will not approve exemption of the area that would result in encroachment of the aquifer exemption boundary into a private well capture zone.

iii. The Permittee must obtain the Director's approval of the aquifer exemption before installing any injection and production wells that would result in expansion of the aquifer exemption boundary beyond the locations shown in Figures 2a and 2b.

2. Logging of Wellfield Delineation and Pump Test Well Drillholes

a. The Permittee must log all delineation drillholes and the pump test wells drillholes to determine lithologic horizons and the extent of the ore deposits within the wellfield. The list of logs is included in Table 2.

b. The Permittee must provide this information to the Director in the form of a descriptive narrative containing detailed map(s) and cross sections. The descriptive narrative interpreting the results of logs and tests must be prepared by a knowledgeable log analyst.

c. The Permittee must identify in the report any injection interval perimeter monitoring wells completed in a uranium ore body.

d. The Permittee must submit the report to the Director as part of the Injection Authorization Data Package Report described in Section H of this Part.

Table 2. Delineation and Pump Test Well Drillhole Logging Program

TYPE OF LOG	PURPOSE	DUE DATE
Gamma Ray	To identify ore depth and thickness	Prior to setting well casing
Self Potential	To identify confining zones and aquifer units.	Prior to setting well casing
Resistivity	To identify confining zone depth and thickness	Prior to setting well casing
Physical Geologic Log	To identify lithology and stratigraphy	During drilling

e. The detailed map(s) and cross sections must show:

i. the ore deposit locations color-coded to differentiate the different ore horizons within the injection interval;

ii. the locations of proposed injection/production wells and monitoring wells color-coded to different well type and completion interval;

iii. wellfield cross sections as described in Table 3 with ore deposits, aquifer units and confining zones labeled as applicable;

iv. new delineation drillholes labeled on a separate map and representative drillhole logs included in cross-sections;

v. cross section locations index map; and

vi. a potentiometric surface elevation map for each aquifer intersected by a drillhole or well.

f. If appropriate to better fit the ore deposit configurations, the Permittee may propose alternate wellfield cross section configurations that are different from those described in Table 3 and shown in Appendix A figures, without modification to this Area Permit.

Table 3. Example Cross Section Locations Required for Each Wellfield

Wellfield	Number of Cross Sections
D-WF1	A minimum of 2 cross sections trending NE/SW along trend of Lower Fall River roll fronts delineating Lower Fall River ore deposits and approximately parallel to cross section H – H', as shown in Appendix A, Figure A1. A minimum of 5 cross sections intersecting the first two cross sections, also delineating Lower Fall River ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower Fall River ore deposits.
D-WF2	A minimum of 1 cross section along trend of Middle and/or Lower Chilson roll fronts delineating Middle and/or Lower Chilson ore deposits approximately parallel to cross section J – J' as shown in Appendix A, Figure A1. A minimum of 1 cross section intersecting the first cross section also delineating Middle and/or Lower Chilson ore deposits located in the middle of the west side of D-WF2, as shown in Appendix A, Figure A1. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore targeted by D-WF2. Also include any intersected ore deposits targeted by D-WF1, D-WF3 and D-WF4 as applicable.
D-WF3	A minimum of 1 cross section along trend of Lower Fall River roll fronts delineating Lower Fall River ore deposits, as shown in Appendix A, Figure A1. The cross section must clearly identify aquifer units, confining units and Lower Fall River ore deposits.
D-WF4	**Western Section:** A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits, as shown in Appendix A, Figure A2. A minimum of 3 approximately NE/SW cross sections intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the western section of D-WF4. Also include any intersected ore deposits targeted by D-WF3 as applicable. **Middle Section**: A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits as shown in Appendix A, Figure A2. A minimum of 1 approximately NE/SW cross section intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the middle section of D-WF4.
D-WF4	**Eastern Section:** A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits as shown in Appendix A, Figure A2. A minimum of 2 approximately NE/SW cross sections intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the eastern section of D-WF4.
B-WF1	A minimum of 1 cross section trending approximately along cross section A – A' in Class III Permit Application Plate 6.12, along trend of and delineating Lower and Middle Chilson ore deposits. A minimum of 4 approximately north/south trending cross sections intersecting cross section A – A' also delineating Lower and Middle Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower and Middle Chilson ore deposits targeted by B-WF1. Also include any intersected ore deposits targeted by B-WF2, B-WF3, B-WF4 and B-WF6 as applicable.
B-WF2	A minimum of 1 cross section trending approximately along cross section D – D' in Class III Permit Application Plate 6.12, along the trend of and delineating Middle Chilson ore deposits. A minimum of 3 approximately NW/SE trending cross sections intersecting cross section D – D' also delineating Middle Chilson ore deposits. The cross sections must clearly identify aquifer

	units, confining units and Middle Chilson ore deposits targeted by B-WF2. Also include any intersected ore deposits targeted by B-WF1, B-WF3 and B-WF4 as applicable.
B-WF3	A minimum of 1 cross section trending approximately SW/NE along the trend of the Upper Chilson roll fronts and delineating Upper Chilson ore deposits. A minimum of 2 approximately NW/SE trending cross sections intersecting the first cross section. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore deposits targeted by B-WF3.
B-WF4	A minimum of 1 cross section trending approximately east/west as shown in Appendix A, Figure A3, delineating Middle and/or Lower Chilson ore deposits. A minimum of 5 approximately north-south trending cross sections intersecting the first cross section also delineating Middle and/or Lower Chilson ore deposits. One north-south trending cross section must be approximately parallel to the portion of cross section C – C' in B-WF4. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF4. Also include any intersected ore deposits targeted by B-WF1, B-WF2 and B-WF3 as applicable.
B-WF5	A minimum of the 3 cross sections shown in Appendix A, Figure A4 delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore deposits targeted by B-WF5.
B-WF6	A minimum of the 7 cross sections in the approximate locations shown in Appendix A, Figure A5 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF6. Also include any intersected ore deposits targeted by B-WF1 and B-WF7 as applicable.
B-WF7	A minimum of the 1 cross section shown in Appendix A, Figure A5 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF7.
B-WF8	A minimum of the cross sections shown in Appendix A, Figure A6 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF8.
B-WF9	A minimum of the 2 cross sections shown in Appendix A, Figure A4 delineating Middle (and Lower, if applicable) Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle (and Lower, if applicable) Chilson ore deposits targeted by B-WF9. Also include any intersected ore deposits targeted by B-WF5 as applicable.
B-WF10	A minimum of the 2 cross sections shown in Appendix A, Figure A7 delineating Lower Fall River ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower Fall River ore deposits targeted by B-WF10.

3. Plugging and Abandonment of Wellfield Delineation Drillholes

After drilling and logging, all delineation holes that are not used for injection, production or monitoring well construction must be plugged and abandoned in a manner that ensures the integrity of all intersected confining zones remains intact. The integrity of intersected confining zones must be demonstrated by the results of the wellfield pump test required under Part II, Section F.

C. Wellfield Pump Test Design and Pump Test Well Installation

1. The Permittee must design a pump test program for each wellfield to evaluate the hydrogeology and to assess the ability to operate the wellfield and control injection interval fluids.

2. Based on the results of delineation drilling, the Permittee must complete the following wellfield development steps and document each step in the Injection Authorization Data Package Report described in Section H of this Part:

a. Identify the proposed production and injection well locations and approximate screened or open hole intervals.
b. Identify known or suspected locations of exploration drillholes within the wellfield area and adapt pump test design to detect evidence of inter-aquifer communication at the drillhole locations.
c. Design the monitoring well system as required under Part II, Section D below based on production and injection well locations and the refined conceptual geology and hydrogeology provided by the results of wellfield delineation drilling.
d. Install observation wells below the Morrison Formation lower confining zone as described in Table 4. The purpose of the observation wells below the Morrison Formation is to verify that drillholes penetrating the Morrison confining zone have been properly plugged and do not compromise the integrity of the Morrison Formation lower confining zone.
e. Identify all monitoring well locations and screened or open hole intervals.
f. Install all wellfield perimeter monitoring wells.
g. Install all pumping and observation wells to be used during pump testing.
h. Plug and abandon all water supply wells within ¼ mile of the perimeter monitoring well ring or incorporate them into the monitoring system for the wellfield pump test to determine if they have potential to be impacted by ISR operations or to impact ISR operations.

Table 4. Observation Wells for Monitoring the Integrity of the Morrison Formation Lower Confining Zone

Drillholes Penetrating the Morrison Lower Confining Zone within a Wellfield	Location	Wellfield ID	Observation Well Location	Construction of New Well Required?
ELT 14	SESE Section 30 T6S R1E	Dewey WF2	Hydro ID 693 NENW Section 32 T6S R1E	No
DB08-32-11	NENW Section 32 T6S R1E	Dewey WF2		
TRM 38	SENW Section 35 T6S R1E	Burdock WF8	Within Burdock Wellfield 8 between drillholes TRM 38 and DRJ 90.	Yes
DRJ 90	SESE Section 35 T6S R1E	Burdock WF8 Approximately at aquifer exemption boundary		
DB08-1-7	SE Section 1 T7S R1E	Approximately at aquifer exemption boundary of Burdock WF6	Monitor Hydro ID 703 during WF6 pump test, if possible.	No
FBR 31	SESE Section 2 T7S R1E	Burdock WF6 Between aquifer exemption boundary and perimeter monitoring well ring	Between drillholes FBR 31 and DB07-11-31 so it can be used for Burdock WF1 and WF6 pump tests.	Yes
DB07-11-31	NESE Section 11 T7S R1E	Inside Burdock WF1		
DB07-11-18	NESW Section 11 T7S R1E	Inside Burdock WF1	Hydro ID 690 NESW Section 11 T7S R1E	No
DB07-11-16C	NESW Section 11 T7S R1E	Inside Burdock WF1		
RONA 81	SW Section 11 T7S R1E	Inside Burdock WF1		

D. Design and Construction of Wellfield Monitoring Well System

1. Where injection is into an aquifer which contains water with less than 10,000 mg/l Total Dissolved Solids (TDS), monitoring wells must be completed into the injection interval and into any USDWs above the injection interval.

2. Because cementing records for the wellfield injection/production wells must be used to demonstrate the absence of significant fluid movement to fulfill the external mechanical integrity demonstration requirement as described under Part VII, Section D, the monitoring program must be designed to verify the absence of significant fluid movement through the confining zones per 40 CFR § 146.8(c)(4).

3. The monitoring wells must be located in such a fashion as to detect any vertical or horizontal excursion of injection fluids, process by-products, or formation fluids outside the injection interval or wellfield.

4. The wellfield monitoring well system must include:

a. **Wellfield perimeter monitoring well ring:** Monitoring wells must be completed in the injection interval around the wellfield. These wells must be located as specified in Table 5.

b. **Overlying monitoring wells:** Overlying monitoring wells must be completed in all aquifer units overlying the injection interval. These wells must be located as specified in Table 5.

c. **Underlying monitoring wells:**
   i. If the lower confining zone of the injection interval is not the Morrison Formation, then monitoring wells must be completed in the first underlying aquifer unit. These wells must be located as specified in Table 5.
   ii. If the lower confining zone is the Morrison Formation then at least one pump test observation well must be completed in the Unkpapa aquifer below the Morrison Formation near any exploration drillholes penetrating the Morrison Formation to verify that drillholes penetrating the Morrison Formation have not compromised the integrity of the Morrison Formation confining zone. Table 4 lists where the Unkpapa observation wells must be located.

d. **Monitoring wells surrounding possible breaches in confining zones:** If wellfield pump test results indicate a possible breach in a confining unit that cannot be located for corrective action, or corrective action does not completely repair the confining zone breach, then the monitoring well system must be designed to verify that wellfield injection interval fluids will remain within the approved injection interval per 40 CFR § 144.55(b)(4).

e. **Mechanical integrity testing of monitoring wells:** Because the injection interval monitoring wells and any monitoring wells in the first aquifer underlying the injection interval penetrate the injection interval, the Permittee must demonstrate external mechanical integrity for these wells according to Part VII, Section D to verify these wells do not create pathways through the injection interval confining zones for injection interval fluids to move out of the injection interval. The Permittee must plug and abandon any monitoring well for which mechanical integrity cannot be demonstrated. The plugging and abandonment procedures must be conducted according to the requirements under Part XI.

Table 5. Monitoring Well Location Requirements

Type of Monitoring Well	Location Requirements
Injection interval wellfield perimeter monitoring well ring	1) No farther than 400 feet from the outermost wellfield well. 2) Maximum spacing of either 400 feet or spacing that will ensure no greater than a 70 degree angle between adjacent perimeter monitor wells and the nearest wellfield well.
Overlying monitoring wells	1) Monitoring wells completed in first aquifer unit overlying the injection interval: a density of at least one monitoring well per 4 acres of well field area. 2) Monitoring wells completed in subsequent aquifer units overlying the injection interval: a density of at least one well per 8 acres of wellfield area.
Underlying monitoring wells	A density of one well per 4 acres of wellfield area except for aquifers below the Morrison Formation lower confining zone.
Unkpapa Formation observation wells	Unkpapa Formation observation wells are specified in Table 4. Monitoring of Unkpapa Formation observation wells is required only during the wellfield pump tests in order to evaluate the integrity of the Morrison Formation lower confining zone.

E. Formation Testing

1. The Permittee must conduct the formation testing as required in this Section. Table 6 provides a summary of the required testing.

Table 6. Formation Testing Program

Type of Test	Purpose	Timing
Water level measurements in all pump test wells	• To determine potentiometric surfaces of the injection interval and monitored non-injection interval aquifers. • To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells, improperly completed wells or naturally occurring features such as fractures.	• After construction of all wellfield pump test wells is completed • The static potentiometric surface for each aquifer has stabilized from well development activities, and • Prior to initiation of pump testing activities.
Sampling and Analysis of Injection Interval and Non-injection Interval Monitoring Wells	• To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells or naturally occurring features such as fractures. • To determine concentrations of water quality parameters in Table 8.	Prior to initiation of pump testing activities per Section E.2.b of this Part.
Wellfield pump test	• To demonstrate that control of injectate and injection interval formation fluids is able to be maintained throughout the ISR process and groundwater restoration. • To establish that the production and injection wells are hydraulically connected to the injection interval perimeter monitoring wells. • To evaluate whether the production and injection wells are hydraulically isolated from non-injection interval monitoring wells. • To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells, improperly completed wells or naturally occurring features such as fractures.	Prior to receiving written Authorization to Commence Injection from the Director

2. The Permittee must follow these procedures while conducting the formation testing described in Table 6:

   a. Determination of Aquifer Potentiometric Surfaces

   i. Once the potentiometric surface has stabilized within each aquifer after well development, static potentiometric surface water levels must be measured in every perimeter and non-injection interval monitoring well and the injection or production wells installed in the wellfield for the wellfield pump test.

   ii. Based on these data points, the Permittee must provide pre-pump test potentiometric surface elevation maps for the injection interval and each non-injection interval aquifer being monitored in order to identify drawdown resulting from the wellfield pump test.

   iii. These water levels must be considered in the determination of the baseline water levels to be

used to evaluate the presence of a wellfield cone of depression signifying hydraulic control of wellfield groundwater during the wellfield pump test and to identify breaches in confining zones for non-injection interval monitoring wells.

iv. Once the potentiometric surface has stabilized within each aquifer after the pump test, static potentiometric water levels must be measured in every perimeter and non-injection interval monitoring well and the injection or production wells installed in the wellfield for the wellfield pump test, prior to the initiation of injection into the wellfield to determine if there have been any changes in water levels not attributable to changes in barometric pressure.

b. Sampling and Analysis of Injection Interval and Non-injection Interval Monitoring Wells

Sampling and analysis of groundwater from all wellfield injection interval and non-injection interval monitoring wells is required to obtain background concentration data for each aquifer. This data is needed to provide pre-operational groundwater quality data for the Conceptual Site Model as required under Part IV, Section A and to provide groundwater quality data in the injection zone downgradient from the wellfield for comparison with the Table B-1 permit limits.

i. After the construction and development of the wellfield perimeter monitoring wells, the wellfield injection interval wells used to determine Commission-approved background and the monitoring wells completed in aquifers above and below (where applicable) the injection interval, the Permittee must collect groundwater samples from each of these wells according to the following procedures:

A) The Permittee shall purge at least three casing volumes prior to sample collection and measure the field parameters listed in Table 7 at the surface as fluid is pumped out of the well to determine when collection of a representative sample is possible.

B) The Permittee must collect a sample only after the field parameters meet the stabilization criteria in Table 7, indicating that the water quality indicator parameters have stabilized.

C) If stabilization is not occurring and the procedure has been strictly followed, then sample collection can take place once three (minimum) to six (maximum) casing volumes have been removed.

D) The Permittee must include stabilization information in the Injection Authorization Data Package Report described in Section H of this Part.[1]

Table 7. Field Parameters to be Monitored and Stabilization Criteria to Meet before Sample Collection

Parameter	Stabilization Criteria
pH	± 0.1 pH units
Specific conductance	± 3% µmhos/cm at 25 °C
Temperature	± 0.5 °C
Dissolved oxygen	± 0.3 mg/L

ii. After following the procedures in Part II, Section E.2.b.i above, the Permittee must collect and handle groundwater samples according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*.

[1] The EPA recommends capturing and storing the groundwater pumped from each perimeter monitoring well (except for any completed in an ore deposit) to use as the injectate for the Step Rate Tests described in Part II, Section J.

iii. The samples must be analyzed for the water quality parameters listed in Table 8 using the analytical methods shown. Equivalent analytical methods may be used after prior approval by the Director.

iv. The Permittee must compare analytical results from samples collected from the downgradient wellfield perimeter monitoring-ring wells for ISR constituents listed in Table B-1 in Appendix B of this Permit. If naturally occurring background concentrations for any constituent exceed the permit limit listed in Table B-1, the Permittee must determine the background concentration to use as the alternate permit limit based on analytical results from the perimeter monitoring wells on the downgradient side of the wellfield.

v. The Permittee must develop a brief report that includes the analytical results and a description of statistical methods used for computing the background concentration for each constituent for which a background concentration is required and include the report in the Injection Authorization Data Package Reports per Part II, Section H.3.x for review and approval.

vi. Requirements related to groundwater sample analysis for radium-228: If radium 228 is not detected in the initial sample from each well radium-228 may be removed from the analyte list for remaining sampling and analysis events. However, if radium-228 is detected in the first sample, it must remain on the analyte list for future samples collected from that well.

Table 8. Water Quality Parameter List

Test Analyte/Parameter	Units	Analytical Method
Physical Properties		
pH*	pH Units	A4500-H B
Total Dissolved Solids (TDS)	mg/L	A2540C
Specific Conductance*	µmhos/cm at 25°C	A2510B or E120.1
Turbidity	nephelometric turbidity units (NTU)	EPA-NERL: 180.1
Field-Measured Parameters		
Temperature**	°C	2014 EPA Region 4 SOP (Temperature)
Dissolved Oxygen**	mg/L	2017 EPA Region 4 SOP (DO)
Common Elements and Ions		
Carbon Dioxide	Convert mg/L to atm	A4500-CO2
Total Organic Carbon	mg/L	415.3, 9060A
Dissolved Organic Carbon	mg/L	415.3, 9060A
Total Alkalinity (as $CaCO_3$)*	mg/L	A2320B
Bicarbonate Alkalinity (as $CaCO_3$)*	mg/L	A2320B (as HCO_3)
Calcium	mg/L	E200.7
Carbonate Alkalinity (as $CaCO_3$)*	mg/L	A2320B
Chloride, Cl	mg/L	A4500-Cl B; E300.0
Magnesium, Mg	mg/L	E200.7
Nitrate, NO_3 (as Nitrogen)	mg/L	E300.0
Potassium, K	mg/L	E200.7
Silica, as SiO_2	mg/L	E200.7
Sodium, Na	mg/L	E200.7
Sulfate, SO_4	mg/L	A4500-SO_4 E; E300.0
Dissolved Metals		

Aluminum, Al	mg/L	E200.7, E200.8, E200.9
Antimony, Sb	mg/L	E200.8
Arsenic, As	mg/L	E200.8
Barium, Ba	mg/L	E200.8
Beryllium, Be	mg/L	E200.8
Boron, B	mg/L	E200.7
Cadmium, Cd	mg/L	E200.8
Chromium, Cr	mg/L	E200.8
Copper, Cu	mg/L	E200.8
Fluoride, F	mg/L	E300.0
Total Iron, Fe	mg/L	E200.7
Ferrous Iron, (Fe^{2+})	mg/L	Titration with Dichromate
Lead, Pb	mg/L	E200.8
Manganese, Mn	mg/L	E200.8
Mercury, Hg	mg/L	E200.8
Molybdenum, Mo	mg/L	E200.8
Nickel, Ni	mg/L	E200.8
Selenium, Se	mg/L	E200.8, A3114 B
Silver, Ag	mg/L	E200.8
Strontium, Sr	mg/L	E200.8
Uranium, U	mg/L	E200.7, E200.8
Thallium, Tl	mg/L	E200.8
Vanadium, V	mg/L	E200.7, E200.8
Zinc, Zn	mg/L	E200.8
Radiological Parameters		
Adjusted Gross Alpha***	pCi/L	E900.0
Gross Beta	mRem/Year	E900.0
Radium, Ra-226	pCi/L	E903.0
Radium, Ra-228	pCi/L	E904.0

All water quality parameters determined by laboratory analysis only, except where indicated.
*Field and Laboratory
**Field only
***Excluding radon and uranium.

F. Wellfield Pump Test Requirements

1. The Permittee must monitor the following wells during the pump test to evaluate the hydrogeology and assess the ability to operate the wellfield and control injection interval fluids:
   a. The wells being pumped,
   b. Monitoring wells within the injection interval,
   c. Injection interval perimeter monitoring wells,
   d. Monitoring wells in the immediately overlying non-injection interval aquifer unit,
   e. Monitoring wells in each subsequently overlying non-injection interval aquifer unit,
   f. Monitoring wells in the alluvium, if present,
   g. Monitoring wells in the immediately underlying non-injection interval aquifer unit,
   h. Any additional wells installed for investigating other hydrogeologic features,
   i. Any other wells within ¼ mile of the wellfield perimeter monitoring well ring, and
   j. Any other wells determined to be necessary by the Director or the Permittee.

2. During each pump test the Permittee must measure and record the following parameters:
   a. instantaneous (gallons per minute) and totalized flow (gallons),
   b. periodic pressure transducer measurements (pounds per square inch),
   c. periodic manual water level depth measurements (inches or tenths of feet and feet),
   d. barometric pressure (millibars) (unless using a gauge transducer that is vented to the atmosphere), and
   e. time (scaled as appropriate).

3. The Permittee must conduct the wellfield pump tests with sufficient iterations and using pumping wells in as many locations within the wellfield as necessary to create drawdown in each injection interval perimeter monitoring well.

4. If any injection interval perimeter monitoring well does not show any water level drawdown (decrease in water level not due to barometric pressure fluctuation), the Permittee must recomplete or replace the well and verify that the recompleted or new well is in hydraulic communication with the wellfield injection interval.

5. The wellfield pump test for Burdock Wellfield 10 must be designed in such a manner as to provide data in order to evaluate the impacts from Triangle Pit water on the operation and groundwater restoration of Burdock Wellfield 10.

G. Additional Requirements to Obtain Approval of Exemption of Inyan Kara Aquifers and Authorization to Commence Injection for Burdock Wellfields 6, 7 and 8

1. Because the Chilson Sandstone downgradient from Burdock Wellfields 6, 7 and 8 has been partially oxidized by native groundwater, the Permittee must evaluate the capacity of the downgradient exempted portion of the Chilson Sandstone to attenuate residual ISR contaminants (Appendix B, Table B-1) in restored wellfield groundwater as they travel downgradient toward the aquifer exemption boundary.

2. To fulfill this requirement the Permittee must:
   a. Develop preliminary Conceptual Site Models for wellfields 6, 7 and 8 by conducting all the sampling and testing required for all wellfields as described under this Part.

   b. In addition, the Permittee must expand the Conceptual Site Model for wellfields 6, 7 and 8 by characterizing the geology, hydrologic properties, and geochemical characteristics and processes as described under Part IV, Section A.

   c. In addition, the Permittee must further expand the Conceptual Site Model for wellfields 6, 7 and 8 by conducting batch sorption testing or other appropriate laboratory and field testing methods to provide site-specific sorption parameters for input into the geochemical model, as specified in Part IV, Section C.

   d. Because preliminary Conceptual Site Models for wellfields 6, 7 and 8 must be developed prior to obtaining approval of the exemption of Inyan Kara aquifers and authorization to commence injection, geochemical conditions representing the restored wellfield may be estimated based on data from similar restored wellfields.

   e. On the basis of data collected under this Part, develop preliminary reactive-transport geochemical models for wellfields 6, 7 and 8 as specified in Part IV, Section B to evaluate the potential for ISR

contaminants to cross the aquifer exemption boundary. The Permittee must calibrate the geochemical models using analytical data from field and laboratory testing as specified in Part IV, Section B.5 and conduct uncertainty analysis as specified in Part IV, Section B.6.

f. Submit the Conceptual Site Model and geochemical modeling results to the Director as part of the Injection Authorization Data Package Report for each wellfield, evaluating the potential for ISR contaminants to cross the downgradient aquifer exemption boundary.

3. If, during the wellfield pump tests using a pumping rate simulating production and restoration in Burdock Wellfields 6, 7 or 8, the Chilson aquifer potentiometric surface is drawn down to the point where the proposed injection interval becomes less than fully saturated, the Permittee must develop a 3-D unsaturated groundwater flow model for the area where less than fully saturated conditions are anticipated.
   a. The model must be calibrated to site-specific hydrologic conditions and verified by use of wellfield-specific pump test data.

   b. The model must assess the ability to maintain hydraulic control in the partially saturated injection interval and demonstrate the ability to detect and reverse excursions in the partially saturated injection interval and in the first overlying non-injection interval aquifer.

   c. The model must incorporate the effects of concurrent production and restoration activities in other Burdock wellfields on the Chilson aquifer potentiometric surface in the areas where partially saturated injection intervals are anticipated.

4. The results from the additional requirements for Burdock Wellfields 6, 7 and 8 must be included in the Injection Authorization Data Package Report for each of these respective wellfields.

5. The results from these additional requirements for Burdock Wellfield 6, 7 and 8 must be submitted to the Director as part of the aquifer exemption request.

6. After review of groundwater flow model results, if the Director determines that additional hydrologic testing using pumping and injection is required to verify the groundwater flow model, the Director may issue a Limited Authorization to Inject in order to allow reinjection of groundwater pumped from the field test site pumping well(s) for the purposes of hydrologic testing only.

7. The Director will issue a Limited Authorization to Inject into Burdock Wellfields 6 and 7 only after the aquifer exemption for those two wellfields have been approved according to Section I.3 of this Part.

H. Injection Authorization Data Package Reports

1. An Injection Authorization Data Package Report must be prepared for each wellfield and submitted to the Director for review in order to obtain written Limited Authorization to Inject for each wellfield.

2. The information in this report must become part of the Conceptual Site Model required under Part IV, Section A.

3. Each Injection Authorization Data Package Report must contain a description of all logging and testing procedures required under Part II, Sections B through F (Sections B through G for Burdock Wellfields 6, 7 and 8) and the results of such logs and tests. In summary, each Injection Authorization Data Package Report must contain the following:

a. A descriptive report interpreting the results of logs and tests prepared by a knowledgeable log analyst.

b. A description of the proposed wellfield, including a map delineating the ore deposits, color-coded to differentiate each ore level within the wellfield injection interval.

c. Map(s) showing the proposed production and injection well patterns and locations of all monitoring wells.

d. Map showing all plugged and abandoned exploration drillholes within the wellfield perimeter monitoring ring. Identify any exploration drillholes that had to be replugged.

e. Characterization of faults, fractures, and lithologic variability that might provide preferential flow paths or otherwise affect groundwater flow.

f. Copies of any new or historic drillhole logs annotated to indicate presence of fault, fracture or joint for any drillholes located inside the perimeter monitoring wells ring.

g. Map showing all plugged and abandoned wellfield delineation drillholes within the wellfield perimeter monitoring ring.

h. Wellfield geologic cross section location map and geologic cross sections showing:
   i. the top and bottom depths of the upper and lower confining zones across the wellfield;
   ii. the top and bottom depths of the injection interval across the wellfield; and
   iii. the top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.

i. Isopach maps showing the thickness of the injection interval and the first confining zones overlying and underlying the wellfield injection interval.

j. Descriptions of wellfield monitoring wells, including screened or open hole intervals, that will be used to demonstrate control of injectate and injection interval formation fluids throughout the ISR process and groundwater restoration.

k. Description of well construction activities, including well completion reports and mechanical integrity test dates and results. Include the locations and plugging reports for any wells that had to be plugged and abandoned because mechanical integrity could not be demonstrated.

l. The results from the formation testing required under Section E of this Part.

m. Discussion of how pump testing was performed. Include results and conclusions. Include pump testing raw data, drawdown match curves, potentiometric surface maps, water level graphs, drawdown maps and, when appropriate, directional transmissivity data and graphs.

n. Water level drawdown data demonstrating that each well in the injection interval perimeter monitoring well ring is in communication with the wellfield injection and production wells.

o. The report For Burdock Wellfield 10 must include an analysis of impacts from Triangle Pit water on the operation and groundwater restoration of Burdock Wellfield 10.

p. Estimation of wellfield maximum injection pressure calculated using an estimated fracture gradient value in the fracture pressure equation under Part V, Section F.3 of this Permit and depth

measurements of the injection interval top from wellfield delineation drilling and logging for the purpose of selecting well casing and piping that meet requirements under Part V, Sections E.2.c and E.3.c.

q. The results of the evaluation of all nearby water supply wells with the potential to be impacted by ISR operations or the potential to interfere with ISR operations and the plan for replacing all wells removed from service.

r. A corrective action plan (as required under Part III) identifying areas where breaches in the overlying or underlying confining zones were detected and describing mitigation measures to prevent the migration of injectate and formation fluids out of the injection interval through identified breaches.

s. A description of any wellfield operational controls designed to contain injectate and injection interval fluids within the injection interval to address breaches in confining zones that cannot be precisely located or for which other types of corrective action cannot be performed successfully and operational controls are the method of corrective action. Include a narrative demonstration that the number and placement of non-injection interval monitoring wells are capable of detecting any loss of hydraulic control in that area per 40 CFR § 144.55(b)(4).

t. Schedule for completing mechanical integrity tests, preparing well completion reports and submitting financial responsibility for all injection and production wells prior to bringing the wells online.

u. Groundwater quality data for wellfield and injection interval perimeter monitoring ring wells. Identify any injection interval perimeter monitoring ring wells located in an ore deposit.

v. Proposed locations for Step Rate Test.

w. Proposed source of fluid that will be injected during the Step Rate Test described in Part II, Section J.1 below.

x. The report required under Part II, Section E.2.b.v that includes the analytical results from Part II, Section E.2.b.iii and a description of statistical methods used for computing the background concentration for each constituent for which a background concentration is required.

4. The Permittee must also include information about wellfield level monitoring locations for collection of injection fluid samples and continuous monitoring of injection and production flow rates and volumes required under Part V, Section J.

I. Evaluation of the Injection Authorization Data Package Reports for Authorization to Commence Injection

1. Information to Submit to the Director to Obtain a Limited Authorization to Inject for Testing Purposes

a. In order for the Director to issue a Limited Authorization to Inject only for the purpose of injection to conduct a Step Rate Test for a wellfield, the Injection Authorization Data Package Reports must demonstrate the following:

i. All requirements under Part II, Section B through F (and Section G for Burdock Wellfields 6, 7 and 8) have been met;

ii. Hydraulic connection between the production and injection wells and all injection interval perimeter monitoring wells and downgradient compliance wells;

iii. The overlying and underlying confining zones provide vertical confinement of the injection interval;
iv. Calculation of the hydraulic conductivity, storativity, and transmissivity of the injection interval aquifer unit;
v. Evaluation of anisotropy within the injection interval aquifer unit has been conducted;
vi. Corrective action has been performed to the extent that hydraulic control of injection interval fluids will be maintained during ISR activities until the completion of groundwater restoration;
vii. The number and location of monitoring wells meet permit requirements, provide indication of hydraulic control of injection interval fluids and will detect potential excursions;
viii. Wellfield injection and production wells have mechanical integrity, as required under Part VII, Section B.2; and
ix. Analytical results for the proposed injectate to be used for the Step Rate Test for all constituents listed in Table 8.

b. If:
i. well pump test results indicate the presence of a breach in confinement that the Permittee cannot precisely locate in order to perform corrective action or cannot eliminate through the application of best available technology; and
ii. the Permittee proposes operational controls and monitoring as the corrective action plan, the Director may require the Permittee to perform groundwater modeling or additional pump testing to demonstrate that the wellfield design and monitoring systems are sufficient to control and detect any potential excursions before issuing any Authorization to Commence Injection.

2. Limited Authorization to Inject

a. The Limited Authorization to Inject document will include specification of the approved fluid that will be injected during the Step Rate Test described in Part II, Section J.1.

b. No injection into Burdock Wellfields 6, 7 and 8 will be authorized until after the Aquifer Exemption of Inyan Kara groundwater in that area has been approved by the Director.

3. Information on Well 16 to Submit to the Director to Obtain Approval of the Exemption of Inyan Kara Aquifers for Burdock Wellfields 6 and 7.

The Permittee must submit documentation to the South Dakota Water Rights Program to reclassify well 16 located in NWSE Section 1, T7S, R1E as a monitoring well. Documentation must include a statement that: 1) well 16 should not be used for human consumption because the groundwater produced from the well exceeds the primary drinking water standards for radium and gross alpha and 2) groundwater radon levels are high enough that indoor use of that groundwater should be avoided.

4. Information to Submit to the Director to Obtain Authorization to Commence Injection

a. Pond Design Criteria and Cumulative Effects Analysis of Wellfield Operations

Before the Director will issue written Authorization to Commence Injection, the Permittee must submit information to the Region 8 Air Program for the EPA to determine the applicability of the 40 CFR Part 61 Subpart W regulations, and if necessary, receive construction approval from the EPA.

b. Step Rate Test Results

i. After obtaining the Limited Authorization to Inject for a wellfield, the Permittee must inject only for the purpose of conducting the Step Rate Tests indicated in Table 9.

ii. The Permittee must select a location for conducting the Step Rate Tests that will provide representative fracture gradients for each area and injection interval indicated in Table 9.

iii. The Permittee must use the Step Rate Test guidance document found on the EPA Region 8 UIC Program website: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance

iv. The Permittee must provide information on results from the Step Rate Tests to the Director for evaluation as required under Part II, Section J.

Table 9. Step Rate Tests to be Performed to Determine Fracture Gradient for the Determination of Maximum Allowable Injection Pressure (MAIP)

Area	Injection Interval Formation
Dewey Area	Lower Fall River
Dewey Area	Lower or Middle Chilson Sandstone
Burdock Area	Lower or Middle Chilson Sandstone

J. Step Rate Test and Determination of Fracture Gradient

1. Fracture Pressure Determination

a. The Permittee must run an injection Step Rate Test at a perimeter monitoring well ring well at the locations indicated in Table 9 to determine the site-specific pressure at which fractures form in the injection interval at each testing location.

b. During the Step Rate Test the Permittee must monitor pressure within the injection interval, as well as surface injection pressure.

c. The Step Rate Test results must be submitted to the Director for evaluation.

2. Fracture Gradient Calculation

After the site-specific fracture pressure for the injection interval has been determined based on the Step Rate Test results, the fracture gradient must be calculated according to the following formula:

$$fg=FP/d$$

FP = fracture pressure measured in the injection interval (based on Step Rate Test)
fg = fracture gradient (calculated value)
d = depth to pressure sensor in injection interval

3. Loss in Pressure due to Friction

a. There may be a pressure loss due to friction between the injectate and the injection tubing.

b. During the Step Rate Test, if the pressure measured at the injection interval sensor is less than the pressure measured at the surface gauge plus the pressure from the weight of the injectate in the injection tubing, this is the pressure loss due to friction.

c. This pressure loss due to friction may be calculated and added back into the MAIP calculated under Part V, Section F.4.

K. Plugging and Abandonment of Wellfield Wells

If evaluation of the Injection Authorization Data Package Reports as described under Section I of this Part indicate the hydrogeologic conditions are not conducive to the in-situ recovery of uranium, the Director will not issue Authorization to Commence Injection and the Permittee must plug and abandon all wellfield wells according to the requirements under Part XI of this Area Permit.

PART III. CORRECTIVE ACTION

Corrective action requirements are as follows.

A. Water Supply Wells near Wellfields

1. All water supply wells located within the wellfield and within ¼ mile of the wellfield must either be plugged and abandoned or monitored during the wellfield pump test to determine if they have potential to be impacted by ISR operations or to impact ISR operations.

2. If wellfield pump test results demonstrate that a water supply well causes no breach in a confining zone, the Permittee may continue to use the well for monitoring.

3. The Permittee must notify the well owner in writing prior to removing any well from private use and work with the well owner to determine whether a replacement well or alternate water supply is more appropriate.

4. The Permittee must install locking wellhead covers on private wells under the Permittee's control within the Project Area to ensure that only the Permittee and authorized representatives have access to these wells.

B. Wellfield Delineation Drilling and Pump Testing

If the more detailed hydrogeologic evaluation during the delineation drilling or wellfield-scale pump testing prior to the development of each wellfield indicates a breach in a confining zone that could serve as a potential pathway for groundwater movement through an unplugged or improperly plugged drillhole, a well or a natural geologic structure:

1. The Permittee must attempt to determine the location of the feature causing the breach using best available technology and best professional practices.

2. If the feature can be located and is man-made, then corrective action must be performed to repair the breach in confinement.

3. If the feature is a naturally occurring geologic structure or if the feature cannot be located precisely enough to conduct corrective action or cannot be repaired, then wellfield operational controls must be designed to contain injection interval fluids to the injection interval.

4. When features causing a breach cannot be precisely located or corrective action cannot be successfully performed and operational controls are the method of corrective action, the Permittee must demonstrate that the number and placement of non-injection interval monitoring wells are capable of detecting any loss of hydraulic control in that area per 40 CFR § 144.55(b)(4).

5. Demonstration of the effectiveness of the monitoring system may include additional pump testing or groundwater modeling as determined by the Director after the evaluation of the wellfield Injection Authorization Data Package Report.

C. ISR Operations

1. If vertical excursion cannot be controlled in the area around a breach that cannot be located or remediated with corrective action because operational controls are not effective, the Permittee must be prohibited from injection activity in this location.

2. The Permittee must remediate any vertical excursions that have occurred in the area around a breach that cannot be located or remediated.

3. Excursion monitoring must continue in the area where around a breach that cannot be located or remediated with corrective action even though there is no longer any injection activity occurring.

D. Documentation of Corrective Action

1. The Permittee must document all corrective action activities performed according to the requirements under Part III Sections A and B and include the information in the Injection Authorization Data Package Report for each wellfield as described in Part II, Section H.3.r.

2. The Injection Authorization Data Package Report must also include a description of corrective action implementation and completion status.

PART IV. REQUIREMENTS FOR DEVELOPMENT OF A CONCEPTUAL SITE MODEL AND REACTIVE TRANSPORT GEOCHEMICAL MODELING

A. Development of a Conceptual Site Model

The Permittee must develop a Conceptual Site Model (CSM) for the purpose of supporting reactive transport geochemical modeling to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary. The constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. Development of the CSM will include the information already available in the Class III Permit Application, the information required under Part II, Section H for each wellfield as part of the Injection Authorization Data Package Reports, and additional information required for geochemical modeling described in this Part. A complete representation of the geology, hydrologic properties, and geochemical characteristics and processes for each wellfield is necessary to minimize uncertainty of model predictions concerning the potential for ISR contaminants to cross the aquifer exemption boundary.

This information will become part of the Wellfield Closure Plan for all ISR wellfields. With the exception of the preliminary CSMs developed for Burdock wellfields 6, 7, and 8 under Part II Section G, a CSM is not required as part of the Injection Authorization Data Package Report unless site-specific data indicate oxidizing conditions downgradient from the wellfield.

1. The extent of the CSM for geochemical modeling must encompass an area sufficient to characterize flow paths across each wellfield injection interval, including:

a. Upgradient of wellfields,
b. Within wellfields,
c. Downgradient of wellfields within the aquifer exemption boundary, and

d. Margin beyond the downgradient aquifer-exemption boundary sufficient to protect USDWs.

2. The Permittee must include the following information in the CSM:

a. Geology

i. Maps indicating the locations of ore bodies.

ii. Contour maps indicating the structure of each injection interval across the Dewey and Burdock Areas.

iii. A wellfield geologic cross section location map and geologic cross sections showing:

A) Locations of ore bodies;

B) Top and bottom depths of the injection interval across the wellfield, including localized confining layers within the interval;

C) Top and bottom depths of the upper and lower confining zones across the wellfield; and

D) Top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.

iv. Isopach maps showing the thickness of each injection interval and the first confining zones overlying and underlying the wellfield injection interval.

v. Characterization of localized confining layers that could affect groundwater flow paths and transport of ISR contaminants toward the aquifer exemption boundary.

vi. Characterization of faults, fractures, and lithologic variability that might provide pathways for preferential flow or otherwise affect groundwater flow.

b. Hydrologic Properties

For each injection interval, the CSM must include site-specific data to assess:

i. Aquifer hydraulic conductivity, transmissivity, and storativity;

ii. Aquifer porosity;

iii. Aquifer heterogeneity and anisotropy;

iv. Potentiometric surface representing static conditions prior to injection activities;

v. Potentiometric surface representing stabilized post-restoration conditions;

vi. Groundwater velocities; and

vii. Aquifer confinement and hydraulic connection to overlying and underlying aquifers.

c. Geochemical Characteristics

Because results of reactive transport modeling are sensitive to geochemical input parameters, site-specific characterization of aquifer geochemistry is required.

i. Characterization of aqueous geochemistry for the CSM must include analysis of the following:

A) Groundwater representing background conditions within, upgradient, and downgradient of each wellfield for water-quality parameters listed in Table 8;

B) Injection fluids for analytes listed in Table 15; and

C) Groundwater representing post-restoration stability conditions within each wellfield for parameters listed in Table 8.

ii. Characterization of solid-phase geochemistry must include evaluation of the following:

A) Quantitative mineralogy representative of lithologic variations within injection intervals, particularly with respect to minerals that can have a substantial effect on uranium

mobility, including but not limited to calcite, clay minerals, hematite, iron oxyhydroxides, and pyrite/marcasite.

B) Petrologic and mineralogic characteristics that can affect geochemical properties, such as bulk density, grain size, cementation, overgrowths, and nodules.

C) Presence of metals listed in Appendix B, Table B-1 for which solubility and transport may be affected by geochemical conditions of the background aquifer or restored wellfield; and

D) Content of organic carbon.

iii. Areas where groundwater geochemistry and mineralogical characteristics of the aquifer solids indicate reduced or oxidized conditions must be delineated.

d. Geochemical Processes

i. To ensure important geochemical processes at the Dewey-Burdock site are represented, the CSM must include evaluation of the following interactions between fluids and solids in each injection interval:

A) Interactions between native groundwater and aquifer solids under background pre-mining conditions.

B) Interactions between upgradient groundwater and the aquifer in the wellfield after restoration is completed.

C) Interactions between restored groundwater in the wellfield and the aquifer downgradient of the wellfield.

D) Interactions between upgradient groundwater and the aquifer downgradient of the wellfield after the groundwater has passed through the restored zone.

ii. The following geochemical processes must also be evaluated in the CSM:

A) Effect of aqueous uranyl-carbonate complexes and calcium-carbonate-uranyl complexes on uranium mobility.

B) Desorption of uranium and other metals due to pH and other changes in groundwater geochemistry.

C) Dissolution or precipitation of calcite due to changes in pH, alkalinity, and calcium content.

D) The immobilization of uranium by reduction of U(VI) to U(IV) and formation of low solubility uranium minerals (uraninite, pitchblende, and coffinite).

E) Stagnant groundwater zones and dual-domain porosity.

F) Potential effects of residual lixiviant.

G) The possibility that ore-zone uranium was hydraulically bypassed by lixiviant during ISR activities because of lithologic variability and could be mobilized by post-restoration groundwater.

iii. In addition, the following geochemical processes must be evaluated in the CSM for Burdock Wellfields 6, 7, and 8 and any other wellfield found to have downgradient oxidized aquifer conditions:

A) Adsorption of uranium and other metals onto iron and manganese oxyhydroxides or clay

minerals.

B) Release of uranium and other metals from iron and manganese oxyhydroxides under reductive dissolution.
C) The role of competition for sorption sites from other cations and metals in controlling the retardation of uranium and other metals.
D) The effect of cation exchange processes.

iv. The following conditions and geochemical processes also must be included in the CSM for a wellfield if the Director determines that, based on site conditions, they are important to accurately simulate the transport of ISR contaminants toward the aquifer exemption boundary:
A) Redox changes driven by localized heterogeneity in organic carbon;
B) Kinetic rates and rate-limited sorption;
C) Hydrodynamic dispersion;
D) Potential for uranium and other metals to be sorbed onto and transported by colloid-size particles;
E) Potential for microbial populations to affect geochemical conditions after restoration;
F) Residual effects of excursions; and
G) Other important geochemical processes identified during data collection and site characterization.

3. The Conceptual Site Model must meet the following criteria:

a. The CSM is based on data collected from wellfield characterization activities as well as data collected specifically to evaluate geochemical conditions and processes that will affect uranium mobility.
b. Data representing background groundwater chemistry and aquifer solid phases are collected from within the proposed wellfield as well as upgradient and downgradient of the wellfield as specified in Part IV, Sections C.1.a and C.2 and Part II, Section E.2.b.i.
c. Data representing groundwater chemistry and aquifer solid phases within the restored wellfield, including areas having high residual ISR contaminant concentrations, are collected as specified in Part IV, Sections C.1.b and C.2 and Part IX, Section B.4.
d. The CSM incorporates hydrogeologic characteristics representative of the injection interval aquifer.
e. The CSM is based on site-specific data from groundwater samples, core analyses, laboratory batch and/or column tests, well logs, and other appropriate laboratory and field tests, as specified in Part IV, Section C.
f. The areal extent of the CSM encompasses areas upgradient of wellfields, within wellfields, and downgradient of wellfields, including a margin beyond the aquifer exemption boundary sufficient to protect USDWs. The vertical extent of the CSM includes all injection intervals, the first overlying and underlying confining zones and aquifer units overlying and immediately underlying the confining zones, excluding those below the Morrison Formation.
g. Sufficient data were collected to characterize heterogeneity and statistically represent variations in geologic, hydrologic, and geochemical conditions of each injection interval.
h. Geochemical data spatially represent the sites necessary to identify and characterize geochemical processes at the site.
i. Groundwater geochemical data are collected according to applicable procedures described in Part II, Section E.2.b and Part IX, Section A.

j. Groundwater samples are analyzed for the analytes and parameters listed in Table 8 using the specified analytical method or equivalent method with Director's approval. Water-quality analyses have a charge imbalance less than 10 percent.
k. Mineral assemblages and solid phases are quantitatively evaluated and laboratory tests to determine sorption properties are conducted in accordance with Part IV, Section C.3.
l. Data gaps, inconsistencies, and limitations are identified and their potential impact on model results are assessed.

4. The Permittee must update the CSM when any of the following occur:

a. The Permittee identifies data gaps or uncertainty concerning geology, hydrologic properties, geochemical characteristics, and/or geochemical processes that could affect mobility and transport of uranium and other metals at the Dewey-Burdock site. When this occurs, the Director may require the Permittee to collect additional data or develop alternative CSMs to accommodate and characterize the areas of uncertainty as they relate to evaluating the potential for ISR contaminants to cross the aquifer exemption boundary. This could include, but is not limited to, characterizing geochemical processes listed under Section A.2.d.iv of this Part.
b. Upon the identification of an expanding excursion plume as required under Part IX, Section C.5.d.
c. Burdock Wellfields 6, 7, and 8 are developed. If the Director approves the exemption of Inyan Kara aquifers in these wellfield areas and authorizes injection into these wellfields, the preliminary CSMs developed under Part II, Section G must be updated with site-specific groundwater and solid-phase data collected from the restored wellfield prior to conducting final geochemical modeling for the Wellfield Closure Plan.

B. Reactive Transport Geochemical Modeling

The Permittee must conduct reactive transport geochemical modeling for each wellfield to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary. Constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. The objective of the modeling is to demonstrate that the concentration of each ISR contaminant will not exceed the permit limit (or alternate permit limit, if applicable) at the aquifer exemption boundary within the injection-interval aquifer. Modeling results will become part of the Wellfield Closure Plan for all ISR wellfields.

1. The Permittee must incorporate the following scenarios into the geochemical modeling:

a. Evaluation of the restored wellfield's capacity to maintain long-term geochemical stability as upgradient groundwater flows across the wellfield.
b. Assessment of the downgradient portion of the exempted aquifer to attenuate residual contamination as restored groundwater flows out of the wellfield.
c. Where another wellfield is located upgradient adjacent to the wellfield, chemistry of the post-restoration groundwater within the upgradient wellfield must be included in the modeling scenarios.

2. Predictive modeling of contaminant transport for each wellfield closure

The Permittee must conduct predictive modeling of contaminant transport for each wellfield closure. The preliminary modeling conducted under Part II Section G as part of the Injection Authorization Data Package for wellfields 6, 7, and 8 must be updated on the basis of data collected for the full CSM developed under Part IV.A, including characterization of the restored wellfield, if the Director approves the exemption of Inyan Kara aquifers in these wellfield areas and authorizes injection into these wellfields.

Predictive modeling for each wellfield must include the following:

a. Reactive transport of post-restoration fluids in the wellfield flowing downgradient toward the aquifer exemption boundary;
b. Reactive transport of upgradient groundwater, including from any adjacent wellfields, into the restored wellfield and subsequently farther downgradient toward the aquifer exemption boundary.

3. Model Specifications

a. The models must be constructed based on the CSM described in Part IV, Section A of this permit and requirements specified in Part IV, Section C.
b. The areal extent of the model domain may vary by wellfield, but must incorporate an area that enables simulation of groundwater flow and geochemical processes from upgradient, through the wellfield, and into the area downgradient from the wellfield, including a margin beyond the aquifer exemption boundary sufficient to demonstrate protection of USDWs.
c. The vertical model extent must represent the full injection interval aquifer. In the event that a vertical excursion out of the injection interval is indicated, the model must also include the excursion interval and confining zones.
d. Cell size and spacing in the model domain must be based on groundwater flow velocity and allow for adequate resolution when simulating geochemical processes along flow paths.
e. Reactive transport models may be 3-D, 2-D, or 1-D as needed to represent conditions across the site. If 2-D or 1-D modeling is used, enough simulations must be used to represent site heterogeneity, including areas of high residual concentrations, within each injection interval and flow-path variations through each wellfield based on site-specific data.
f. Geochemical boundary conditions of the model must:
    i. Accurately represent mineral phases, gas partial pressures, and concentrations of constituents in groundwater;
    ii. Be based on site-specific field and laboratory data;
    iii. Represent the oxidation states of the mineral assemblages and saturation indices of the groundwater; and
    iv. Not overly constrain model results to produce unrealistic modeling predictions.
g. Model runs must cover a sufficient timeframe to reestablish natural groundwater flow conditions and simulate the transport of ISR contaminants to the aquifer exemption boundary, including the potential rebound of uranium and other metals.
h. Modeling must include ISR contaminants listed in Appendix B, Table B-1. Modeling is not required for ISR contaminants that have been shown by monitoring under Part IX, Section B.3.a to have concentrations at or below the permit limit or the groundwater background concentration at all injection interval wells within the wellfield after completing ISR operations and prior to initiating wellfield restoration.

4. Equilibrium, Kinetic, and Sorption Data

a. The thermodynamic data used by the modeling program must contain up-to-date information available on uranium and other constituents of concern at the site, such as, but not limited to, those presented by Guillaumont et al. (2003), Dong and Brooks (2006), Mahoney et al. (2009), and Mühr-Ebert et al. (2019).
b. Where important reactions or kinetics (if simulated) are not included in the model's thermodynamic database, the databases must be augmented with site-specific data from laboratory and field studies as described in Part IV, Section C.

c. The activity-coefficient model used to simulate reactions must be chosen based on the range of ionic strengths and constituents measured in background groundwater and the post-restoration groundwater within the wellfield.

5. Model calibration

To reduce model prediction uncertainty concerning the long-term fate and transport of ISR contamination, the model must be calibrated as follows:

a. The model must be calibrated by using site-specific field and laboratory data as described by Part IV, Section C.

b. Prior to conducting predictive simulations, the model must be calibrated to background hydrogeologic and geochemical conditions at the site to verify conditions at the field scale.
   i. The model must have the same domain (2-D or 3-D model) or flow path (1-D model) to be subsequently used for predictive simulations.
   ii. Model calibration must consist of adjusting model input parameters over a representative range of values based on site-specific data to match the distribution of groundwater chemistry observed from upgradient to downgradient across the area where the wellfield will be located.

c. Other calibration approaches may be used with Director's approval.

d. Where the Director finds that model calibration indicates an unsatisfactory match to observed site-specific hydrologic or geochemical conditions, the Director may require that additional data be collected, and/or the model be revised to provide a better match to the observations. This could include, but is not limited to, simulating geochemical processes listed under Part IV, Section A.2.d.iv.

6. Uncertainty Analysis

Uncertainty analysis must attempt to quantify prediction uncertainty concerning the long-term fate and transport of ISR contamination at the Dewey-Burdock site. This may include techniques such as forward Monte Carlo simulations, inverse modeling, or other methods but at a minimum must include the following:

a. Sensitivity analyses for pH, pE, alkalinity, and the quantity or concentration of calcite, pyrite, dissolved oxygen, carbon-dioxide, and organic-carbon, as well as other parameters found to have a substantial effect on simulation results. In addition, for Burdock Wellfields 6, 7, and 8 and any other wellfield found to have downgradient oxidized aquifer conditions, sensitivity analyses must be conducted for sorption parameters based on results of laboratory testing described under Part IV, Section C.3.d.

b. Quantitative evaluation of prediction uncertainty by conducting multiple simulations using a range of hydrologic and geochemical values representative of observed conditions across the site to indicate the potential range of outcomes.
   i. Predictive ranges must include measurement and analytical uncertainties, system heterogeneity, and calibration uncertainty.
   ii. Predictions must be reported with a confidence interval of 90 percent or greater based on the statistical distribution (probability density function) of observed model input parameter values.

c. For model assumptions having high uncertainty, the Director may require that alternative CSMs be generated to explore the effects on reactive transport geochemical model output.

C. Groundwater Sampling, Core Collection, Laboratory Testing, and Field Investigations to Support the Conceptual Site Model and Geochemical Modeling

The Permittee must develop the CSM under Part IV, Section A and conduct geochemical modeling specified under Part IV, Section B based on site-specific data from groundwater sampling, core collection, laboratory testing, and/or other field investigations to minimize uncertainty concerning the potential for ISR contaminants to cross the aquifer exemption boundary. Data collected under this Part must be used in the development of the CSM described under Part IV.A and will become part of the Wellfield Closure Plan for all ISR wellfields.

1. Groundwater Sampling

a. Groundwater samples must be collected from wellfield perimeter monitoring wells, the wellfield injection interval wells used to determine Commission-approved background, and the monitoring wells completed in aquifers above and below (where applicable) the injection interval in accordance with Part II, Section E.2.b.i.

b. Once post-restoration stability monitoring begins, the Permittee must conduct quarterly water quality monitoring for parameters listed in Table 8 in accordance with Part IX, Section B.4, including additional evaluations of any areas with high contaminant concentrations. Final constituent concentrations at the end of the stability-monitoring phase may be used to represent the groundwater chemistry of the restored wellfield.

c. Upon the identification and verification of an expanding excursion plume as described under Part IX, Sections C.4.e and C.4.f, the Permittee must collect a groundwater sample from the impacted well(s) and analyze the sample(s) for the water quality parameters in Table 8 in accordance with Part IX, Section C.4.g.

2. Core Collection

Core samples must be collected at representative locations within each wellfield and from areas upgradient and downgradient from each wellfield to characterize aquifer solids for the CSM based on site-specific data. Core collected to support the CSM must meet the following requirements:

a. Core must include a sufficient number of samples to adequately characterize both horizontal and vertical heterogeneity with respect to hydrogeology and geochemical conditions within the injection interval but at a minimum must include the following:

i. Wellfield Core

A) To characterize background aquifer solid phases, core must be collected from one corehole location per 40 acres of wellfield area or 2 corehole locations, whichever is greater, prior to initiating ISR operations. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality.

B) To characterize aquifer solid phases within the restored wellfield, core must be collected from one corehole location per 40 acres of wellfield area or 2 corehole locations, whichever is greater, after completing the wellfield restoration process. Core collected for the purpose of meeting this minimum requirement must be collected near locations where background core was collected according to Section C.2.a.i.A) above.

ii. Upgradient Core
Core must be collected from the area upgradient of the wellfield based on one corehole location per 2,400 linear feet of wellfield perimeter representing the upgradient side of the wellfield, or 2 corehole locations, whichever is greater. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality and must be from locations distributed across the upgradient area.

iii. Downgradient Core
Core must be collected from the area downgradient of the wellfield based on one corehole location per 1,200 linear feet of wellfield perimeter representing the downgradient side of the wellfield, or 4 corehole locations, whichever is greater. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality and must be from locations distributed across the downgradient area.

iv. Core Representing Vertical Heterogeneity
A minimum of 3 cores must be collected from the injection interval at each corehole location in the wellfield and in areas upgradient and downgradient from each wellfield. Core intervals should be selected to represent lithologic variability within the injection interval. Lithologic logs, geophysical logs, or other methods may be used to identify lithologic variability and target intervals for coring.

b. Core must have sufficient length to accurately identify mineral assemblages and solid phases in quantities representative of the injection interval.

c. Core must be recovered and preserved in a manner to prevent further oxidation so as to be representative of in-situ geochemical conditions for use in laboratory testing.

d. Core collected as part of site-wide characterization activities prior to wellfield development may be used to represent solid phases for individual wellfields provided it meets location, length, and preservation requirements described in Sections C.2.a. through C.2.c. of this Part.

e. Core may be collected as part of well-drilling operations or collected from independent coreholes as needed to characterize the site.

f. All independent coreholes must, upon completion of coring operations at each corehole, be plugged with bentonite or cement grout in a manner which prevents the movement of fluids into or between USDWs in accordance with 40 CFR § 146.10 and applicable portions of the approved plugging and abandonment plan described under Part XI, Section C.

3. Laboratory Testing

Laboratory testing is needed to constrain geochemical parameters and processes controlling uranium mobility and attenuation and to determine sorption parameters and possible mineral dissolution or precipitation reactions.

a. Laboratory testing must be conducted with site-specific solids from the Dewey-Burdock site and fluids representative of geochemical conditions for the background aquifer and the restored wellfield.

b. Core collected under Part IV, Section C.2 must be quantitatively evaluated to determine mineral assemblages and solid phases present that may affect the transport of ISR contaminants toward the aquifer exemption boundary. At a minimum, core must be analyzed to determine quantities of calcite, clay minerals, hematite, iron oxyhydroxides, pyrite/marcasite, and organic carbon.

c. Analytical methods may include:
   i. Mineral and texture evaluation by thin section, transmitted light microscopy and scanning electron microscopy (SEM), and X-ray diffraction;
   ii. Determination of chemical composition by scanning electron microscope, X-ray spectroscopy, and solids analyses for sulfur and organic carbon; and/or
   iii. Other methods as approved by the Director.

d. For wellfields 6, 7, and 8 and any other wellfield determined to have oxidizing downgradient groundwater conditions, geochemical reduction likely will not be the primary process controlling attenuation of ISR contaminants. Therefore, laboratory testing to determine sorption parameters for uranium and metals listed in Appendix B, Table B-1 is required to provide site-specific data for geochemical modeling.

   i. Batch-sorption tests or column studies may be used as needed to provide data for this purpose.
   ii. Laboratory testing must be conducted using standard methods to be determined by the Permittee and approved by the Director.
   iii. Laboratory testing must include analysis of interactions between:
      A) Restored groundwater and core downgradient from the wellfield;
      B) Background upgradient groundwater and core from the restored wellfield;
      C) Downgradient core and the upgradient groundwater after it has passed through and reacted with the restored wellfield. This can be accomplished by using leachate resulting from interactions between background upgradient groundwater and restored wellfield core in a subsequent batch or column test with core from downgradient of the wellfield.
   iv. Water used for testing purposes must represent the geochemistry of restored wellfield groundwater, background upgradient groundwater, and upgradient groundwater after it has passed through and reacted with the restored wellfield, as applicable to assess interactions described in Part IV, Section C.3.d.iii.
   v. A sufficient number of tests must be conducted to represent the range of solid-phase compositions observed within and downgradient from the wellfield, particularly with respect to iron oxyhydroxides, clay minerals, and organic carbon.
   vi. Laboratory tests must be conducted using a range of concentrations for uranium and metals listed in Table B-1 that bracket potential groundwater concentrations to determine how sorption varies with concentration.
   vii. Batch tests must allow sufficient time for effective equilibrium between water and solid phases to occur. Flow in any column tests must be temporarily halted to evaluate concentration rebound and evaluate whether the column is in equilibrium with the injection fluid.
   viii. Laboratory testing for sorption is not required for ISR contaminants shown by monitoring under Part IX, Section B.3.a to have concentrations at or below the permit limit or the

groundwater background concentration at all injection interval wells within the wellfield after completing ISR operations and prior to initiating wellfield restoration.

4. Field investigations

In addition to monitoring and laboratory testing, other investigations to determine geochemical conditions at the Dewey-Burdock site may need to be conducted with the approval of the Director. These could include:

a. Well logging with specialized equipment;
b. Tracer tests or age dating;
c. Geophysics;
d. Field injection and recovery tests; or
e. Cross-hole testing.

D. Wellfield Closure Plan

The Permittee must submit a Wellfield Closure Plan to the Director for review and approval. The Wellfield Closure Plan must demonstrate that the wellfield closure, including plugging and abandonment of all wellfield injection and production wells, will result in adequate protection of USDWs as required under 40 CFR § 146.10(a)(4). If the Wellfield Closure Plan does not demonstrate adequate protection of USDWs, the Director must prescribe aquifer cleanup and monitoring where deemed necessary and feasible to ensure adequate protection of USDWs to fulfill the requirements under 40 CFR § 146.10(a)(4).

1. Process for Wellfield Closure.

a. After the post-restoration stability phase is completed and the geochemical model has been calibrated, the Permittee must conduct reactive transport modeling to evaluate the long-term geochemical stability of the restored wellfield and the potential for ISR contaminants to cross the aquifer exemption boundary according to Section B of this Part. This must include reactive transport of post-restoration fluids in the wellfield downgradient toward the aquifer exemption boundary and reactive transport of upgradient groundwater into the restored wellfield and subsequently farther downgradient toward the aquifer exemption boundary.
b. Once modeling has been completed, the Permittee must submit the Wellfield Closure Plan to the Director for review and approval prior to wellfield closure.
c. The Permittee must not remove wellfield infrastructure necessary for aquifer remediation until the Director has approved the Wellfield Closure Plan and has determined no additional aquifer cleanup and monitoring is necessary and feasible to ensure adequate protection of USDWs per 40 CFR § 146.10(a)(4).

2. Documentation for the Wellfield Closure Plan must include discussion of the following:

a. Geology, hydrologic properties, and geochemical characterization of the CSM.
b. Components of the CSM that are not well defined.
c. Results of data collected from monitoring, laboratory testing, and field investigations.
d. Analysis and uncertainty of data from monitoring, laboratory testing, or other investigations.
e. Geochemical model structure, domain, and discretization.
f. Geochemical inputs to the model.
g. Processes and reactions represented by the model, including the model's thermodynamic database and any updates or modifications to the database. The Permittee must identify any species or phases

that were not able to be represented well in the geochemical model due either to data gaps in sampling or to limitations in the databases for the geochemical modeling program.

h. Results of reactive transport simulations, including an assessment of the potential for ISR contamination to cross the aquifer exemption boundary. Model results must demonstrate that the concentration of each ISR contaminant listed in Appendix B, Table B-1 will at no time exceed the permit limit (or alternate permit limit, if applicable) at the aquifer exemption boundary within the injection interval aquifer.

i. Description of model calibration, including results of monitoring, laboratory and field testing, and modeling performed to match observed hydrologic and geochemical conditions.

j. Uncertainty of model results, including sensitivity analyses and evaluation of predictions over a range of potential site conditions. Predictions must be reported with a confidence interval of 90 percent or greater based on the statistical distribution of observed model input parameter values.

PART V. WELL AND WELLFIELD CONSTRUCTION REQUIREMENTS

The following requirements represent the approved minimum construction standards for well casing and cement for injection and production wells.

A. Approved Well Construction Plan

Details of the approved well construction plan required by 40 CFR § 144.52(a)(1) are incorporated into this Permit in the following sections and Figures 3 through 5.

B. Requirements for Changes to Approved Well Construction Plan

1. Changes in construction plans during construction may be approved by the Director as minor modifications under 40 CFR § 144.41.
2. No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director in accordance with 40 CFR § 144.52(a)(1).
3. After initial well construction is complete, any subsequent changes in well construction must be done by modification in accordance with 40 CFR § 144.39 and § 144.41.

Figure 3. Options for Well Construction Designs

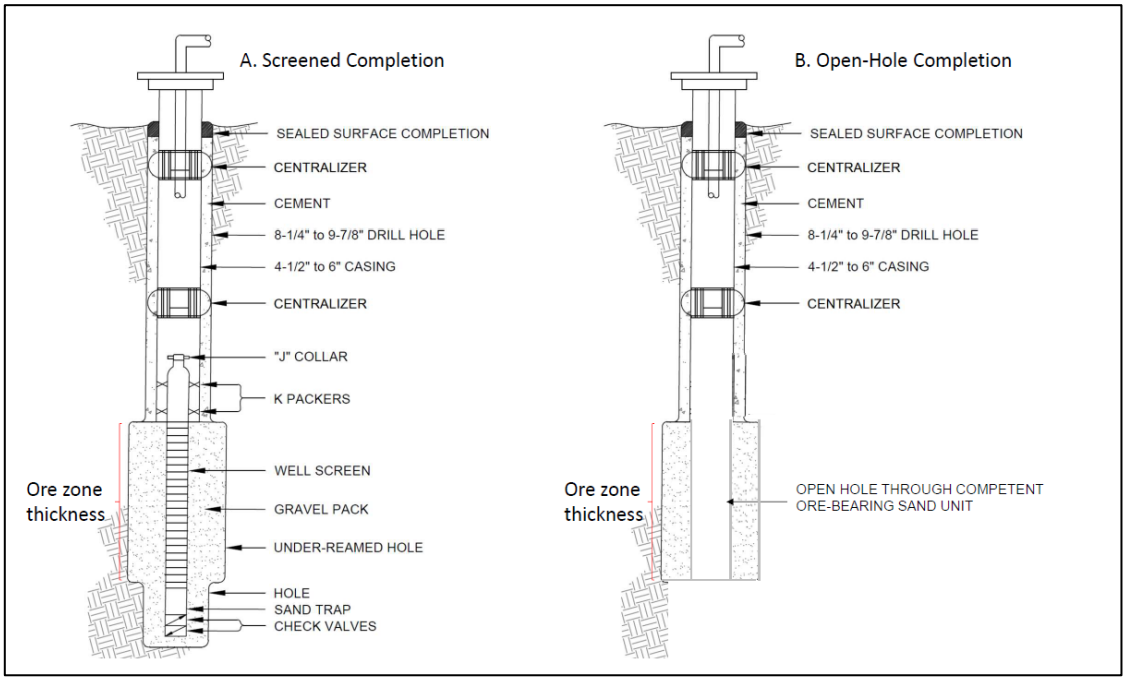


Figure 4. Injection Wellhead Design

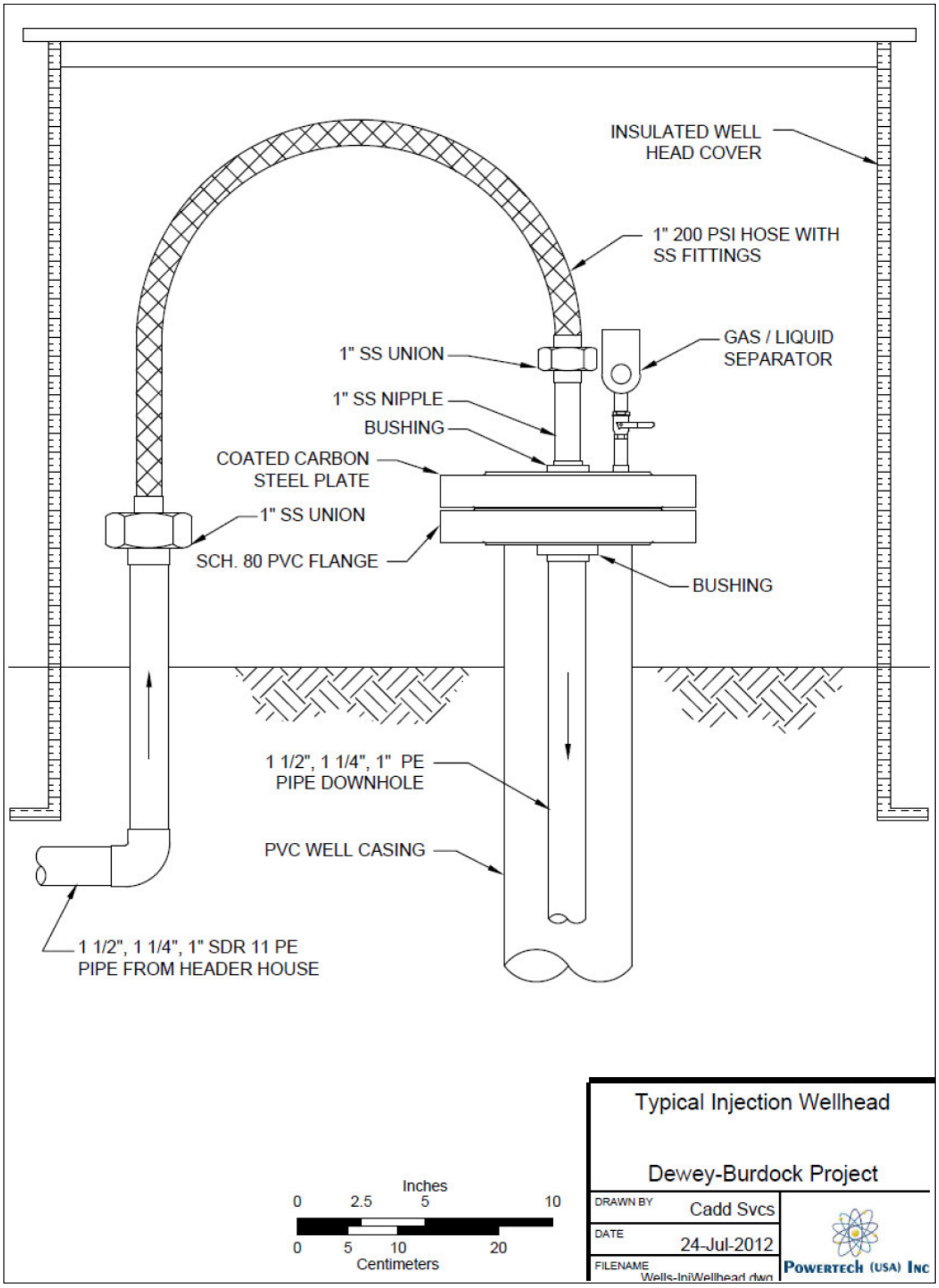
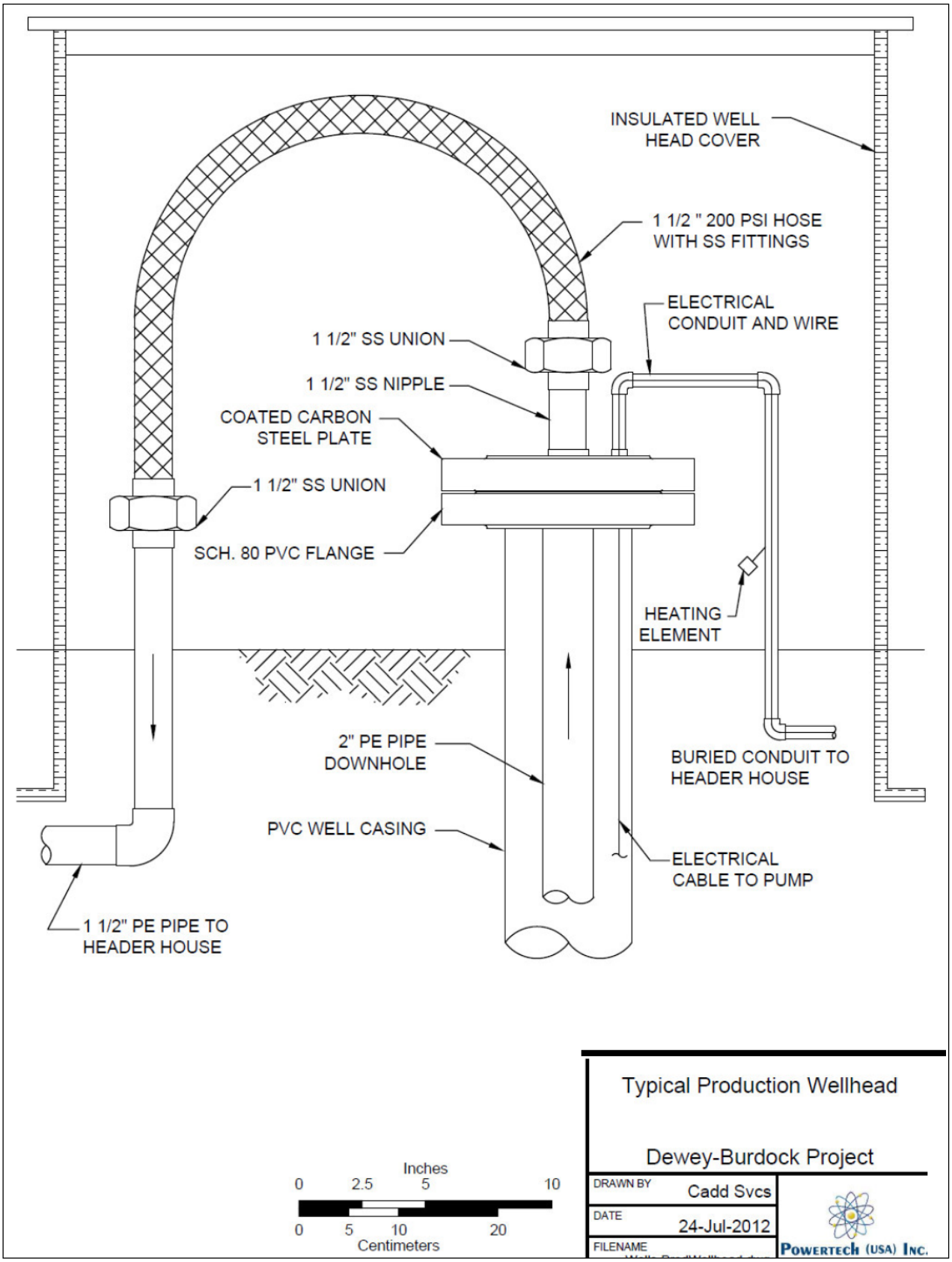


Figure 5. Production Wellhead Design



C. Well Logging

1. The logs listed in Table 10 must be conducted during or after the drilling of all wellfield injection and production wells. A descriptive report interpreting the results of such logs must be prepared by a knowledgeable log analyst and submitted to the Director as part of the well construction report required in Section G of this Part.
2. Deviation checks must be conducted on all holes where pilot holes and reaming are used, unless the hole will be cased and cemented by circulating cement to the surface. Where deviation checks are necessary they must be conducted to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drillings.
3. The Permittee must ensure the log requirements are performed on each injection and production well within the time frames specified in Table 10. Well logs must be performed according to current EPA-approved procedures, where applicable.

Table 10. Well Drillhole Logging Program

TYPE OF LOG	PURPOSE	DUE DATE
Physical Geologic Log	To identify lithology and stratigraphy	During drilling
Gamma Ray	To identify ore depth and thickness	Prior to reaming hole to set casing
Self Potential	To identify depth and thickness of confining zones and aquifer units.	Prior to reaming hole to set casing
Resistivity	To identify depth and thickness of confining zones and aquifer units.	Prior to reaming hole to set casing

D. Well Construction Procedures

1. In order to provide an adequate annular seal, the drillhole diameter must be at least 2 inches larger than the outside diameter of the well casing.
2. A continuous string of joined casing must be placed into the reamed borehole.
3. Casing centralizers must be installed as needed, a minimum of two, along the casing string to ensure that annulus space surrounding the casing is consistent.
4. When designing and installing injection, production and monitoring wells, the Permittee must adhere to the requirements of ASTM F480 and manufacturer's criteria to ensure that the installation does not exceed the well casing hydraulic collapse resistance.

E. Well Casing and Cement

1. General Requirements

a. All injection, production and monitoring wells must be cased and cemented to prevent the migration of fluids into or between USDWs.
b. When a well intersects alluvium at the ground surface, surface casing must be set 50 feet below the base of the alluvium and cemented to the surface.
c. The well casing and cement used in the construction of each injection and production well must be designed for the life expectancy of the well.
d. The well casing, injection pipe and cement must be chemically compatible with the injectate and formation fluids.
e. The piping connecting the wellfield injection and production wells to the header houses must have a pressure rating greater than the highest maximum injection pressure within the wellfield.
f. Remedial cementing may be required if well cement is shown to be inadequate as a demonstration of

external mechanical integrity as discussed in Part VII, Section D.

2. Well Casing Requirements

Injection and production well casing must:

a. Meet or exceed the specifications of ASTM Standard F480 and NSF Standard 14 for thermoplastic pipe, including PVC;
b. Have a Standard Dimension Ratio no greater than SDR 17;
c. Have a pressure rating that exceeds the highest maximum allowable injection pressure for the wellfield and
d. Casing joints must be joined using methods recommended by the casing manufacturer to ensure a water tight seal between joints. The details of the joining methods must be included in the well completion report.

Table 11. Well Casing Dimensions for SDR 17

Proposed Casing Pipe Diameter (inches)	Minimum Casing Pipe Wall Thickness (inches)	Minimum drillhole Diameter (inches)
4.5	0.265	6.5
6.0	0.353	8.0

3. Injection Piping Requirements

The injection pipe must:

a. meet or exceed the specifications of ASTM Standard D3350 for polyethylene pipe,
b. have no greater than SDR 11, and
c. have a pressure rating that exceeds the highest maximum allowable injection pressure for the wellfield.

Table 12. Injection Pipe Dimensions for SDR 11

Proposed Injection Pipe Diameter (inches)	Minimum Casing Pipe Wall Thickness (inches)
1.0	0.09
1.5	0.136

4. Well Cementing Requirements

a. The Permittee must isolate all USDWs by placing cement/bentonite grout between the well casing and the well bore from top of well to top of well screen or open hole interval.
b. The Permittee must use cement/bentonite grout:
    i. Of a quantity and quality to withstand the maximum operating pressure; and
    ii. Which is resistant to deterioration from formation and injection fluids; and
    iii. In a quantity no less than 120% of the calculated volume necessary to fill the borehole-casing annulus from the top of the injection interval to the ground surface.
c. With the casing in place, a cement/bentonite grout must be pumped under pressure into the casing allowing the grout to circulate out the bottom of the casing and back up the borehole-casing annulus to the ground surface.
d. The volume of grout necessary to cement the borehole-casing annulus must be calculated from the bore hole diameter, the outer diameter of the casing, and the depth from the ground surface to the

top of injection interval with a minimum of 20% additional allowance to achieve grout returning to surface.

e. Grout remaining inside the well casing must be displaced by water to minimize the column of the grout plug remaining inside the casing. A bottom hole grout plug must remain inside casing at completion.

f. The casing and grout then must be allowed to set undisturbed for a minimum of 24 hours. When the grout has set, if the annular seal observed from ground surface has settled below ground surface, additional grout must be placed into the annular space to bring the grout seal to ground surface and allowed to set for an additional 24 hours.

5. Well Screen or Open Hole Intervals

a. After the 24-hour (minimum) grout setup period, well construction must be completed by drilling through the grout plug and through the target completion zone to the specified total well depth.

b. The open borehole must then be under-reamed to a larger diameter.

c. Injection intervals and well screen or open hole intervals must be authorized only within the vertical interval of the aquifer exemption.

d. Screened or open hole injection intervals must be determined based on results of wellfield delineation drilling and logging and well borehole logging to determine the vertical thickness of the ore deposit.

e. Information about the well screen or open hole interval must be included in the well completion report.

F. Calculation of Fracture Pressure and Determination of MAIP

1. The fracture pressure must be calculated for each well using the depth to the top of the wellfield injection interval as determined from the well logging results required under Section C of this Part.
2. The calculated fracture pressure for each injection and production well must be included in the well construction report required under Section G of this Part.
3. The fracture pressure must be calculated according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure
fg = fracture gradient (determined from nearest Step Rate Test under Part II, Section J.2)
sg = specific gravity = 1.009 (based on maximum estimated TDS of injectate = 12,000 mg/L)
d = depth to top of well screen or open hole

4. The MAIP Based on Calculated Fracture Pressure

The MAIP measured at each header house pressure gauge must not exceed 90% of the injection formation fracture pressure calculated for each well as required above, plus any pressure loss due to calculated according to Part II, Section J.3. The MAIP at each header house must be set at 90% of the lowest fracture pressure of all the wells connected to the header house (plus any pressure loss due to friction) to assure that the pressure in the injection interval during injection does not initiate new fractures or propagate existing fractures within the injection interval. In no case must injection pressure initiate fractures in the confining zone or cause the migration of injectate or formation fluids into an underground source of drinking water. Any exceedance of MAIP is a violation of this permit and may result in an enforcement action.

5. Alternative MAIP Set at Well Casing or Injection Pipe Operating Pressure

The Permittee has the option to use well casing pipe or injection pipe within the well casing that has a pressure rating below the MAIP set at 90% of the calculated fracture pressure based on the depth to the top of the injection interval plus any pressure loss due to friction calculated according to Part II, Section J.3. In those cases, the MAIP must be set at the well casing or injection pipe operating pressure.

6. The permit limit MAIP must be no greater than the lowest value of the following:

a. The lowest value of MAIP for all injection wells connected to the header house based on 90% of the calculated fracture pressure under Section F of this Part plus any pressure loss due to friction calculated according to Part II, Section J.3.
b. The manufacturer-specified maximum operating pressure for the well casing.
c. The manufacturer-specified maximum operating pressure of the injection pipe.
d. The manufacturer-specified maximum operating pressure of the casing and injection pipe fittings.

7. The well construction report must contain:

a. The manufacturer-specified maximum operating pressure for all components of the injection or production well as required under Section G.6 of this Part and
b. The MAIP determined for the injection well based on requirement 6 above.

G. Well Construction Report

1. After well construction is completed, the Permittee must prepare a well construction report to submit to the Director as required in Part IX, Section E.4.
2. The well construction information must be submitted for each well in electronic format containing the data fields from EPA 7520-9 *Completion Form for Injection Wells* and a narrative description of the procedure for the cementing of well casing as required under Section E.4 of this Part and logs and tests performed as required under Section C of this Part. EPA form 7520-9 found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm.
3. The well construction report must document the adequacy of casing and cementing to prevent USDW contamination through vertical movement of fluids through the borehole-casing annulus.
4. The report must contain information as to how the Permittee met the cementing requirements in Section E.4 of this Part.
5. Remedial cementing may be required if documentation of cementing requirements is inadequate as a demonstration of external mechanical integrity.
6. The well construction report must also contain the manufacturer-specified maximum operating pressure for all components of the injection or production well.
7. The Permittee must indicate the MAIP determined for the injection well in the construction report in accordance with Section F.7 of this Part.

H. Postponement of Construction

1. If the Permittee does not begin construction of at least one of the proposed wellfields within one year of the Effective Date of the Permit, the Permittee must submit an annual Area of Review (AOR) update to the Director until construction commences. The AOR update must include:
   a. Identifying the location and screened interval of any new wells within 2 kilometers (1.2 miles) of the potential wellfield areas, as measured from the perimeter monitoring well rings;
   b. Performing a capture zone analysis for each new drinking water well constructed within the AOR and

c. Adding the new well to the list of operational monitoring wells discussed in Part IX, Section B.2.

2. Prior to commencing wellfield construction, the Permittee must send notification to the Director which includes the approximate date construction will begin and provides an updated AOR.
3. The Permittee must not commence wellfield construction until after receiving written notice from the Director that the AOR update is adequate for the protection of USDWs.

I. Additional Requirements for Manifold Monitoring

Under UIC regulation 40 CFR § 146.33(b)(6), Class III wells may be monitored on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold.

1. Demonstration that Manifold Monitoring Is Equivalent to Individual Well Monitoring

a. In order for the Permittee to use manifold monitoring rather than individual well monitoring and use the header house pressure gauge as the point of compliance for monitoring injection pressure, the Permittee must demonstrate that manifold monitoring is comparable to individual well monitoring.
b. The Permittee must conduct a bounding analysis which will demonstrate for each header house that manifold monitoring is comparable to individual well monitoring using the maximum anticipated carbon dioxide and oxygen injection rates.
c. A demonstration is valid as long as adjustments to the carbon dioxide and oxygen injection rates stay within the range of the bounding analysis.
d. The bounding analysis must be provided to the Director with the next Quarterly Monitoring Report required under Part IX, Section E.8, as described under Part IX, Section E.5.e.

2. The installation of following additional equipment is required for manifold monitoring:

At each wellfield header house the Permittee must install and maintain in good operating condition the following sampling and monitoring devices for manifold monitoring (as shown in Figure 6):

a. a pressure gauge on the injection manifold line for continuous monitoring of injection pressure and daily recording of the injection pressure for the header house;
b. a pressure switch, as an operational control to prevent exceeding designated maximum injection pressure;
c. designated maximum injection pressure for the header house posted in a visible location near the injection manifold line pressure gauge;
d. a flow meter on the injection manifold line for continuous monitoring of injection flow rate; and
e. injection manifolds (as shown in Figures 6 and 7) equipped with:
    i. flow meters labeled with designated well identification numbers;
    ii. flow control valves to regulate the flow to each well and balance individual well patterns; and
    iii. a block valve between the header and the flow meter so that the injection well may be blocked off to service the meter and the well.
f. The Permittee must install a female port (1/2 inch), protected by a valve, to accept a UIC inspector pressure gauge, located in such a way that the inspector can inspect the pressure to compare it to the MAIP.
g. The 1/2 inch female port must be installed at wellheads, in those cases where the MAIP compliance points is located at the wellhead instead of the header manifold.

Figure 6. Injection Header Instrumentation

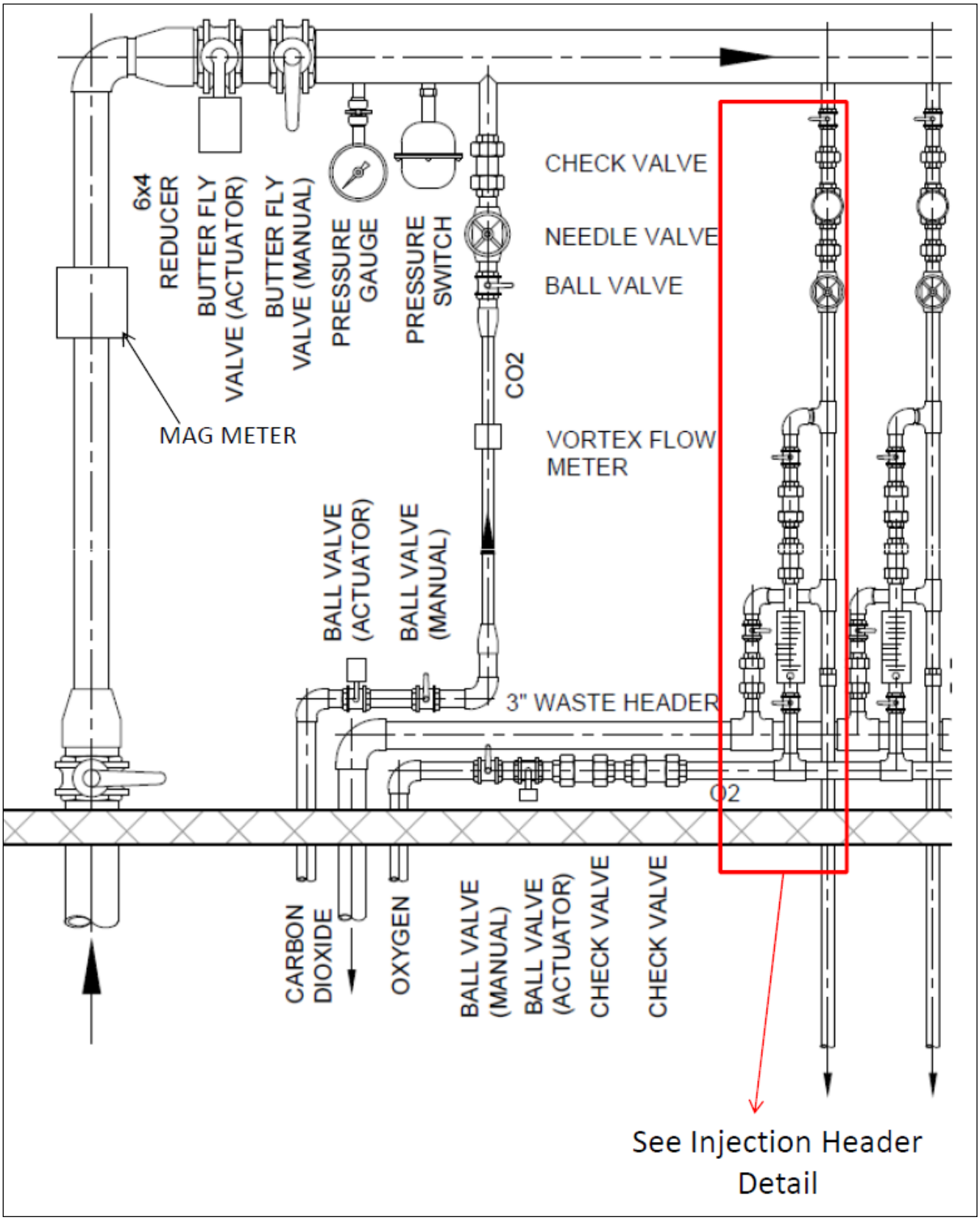
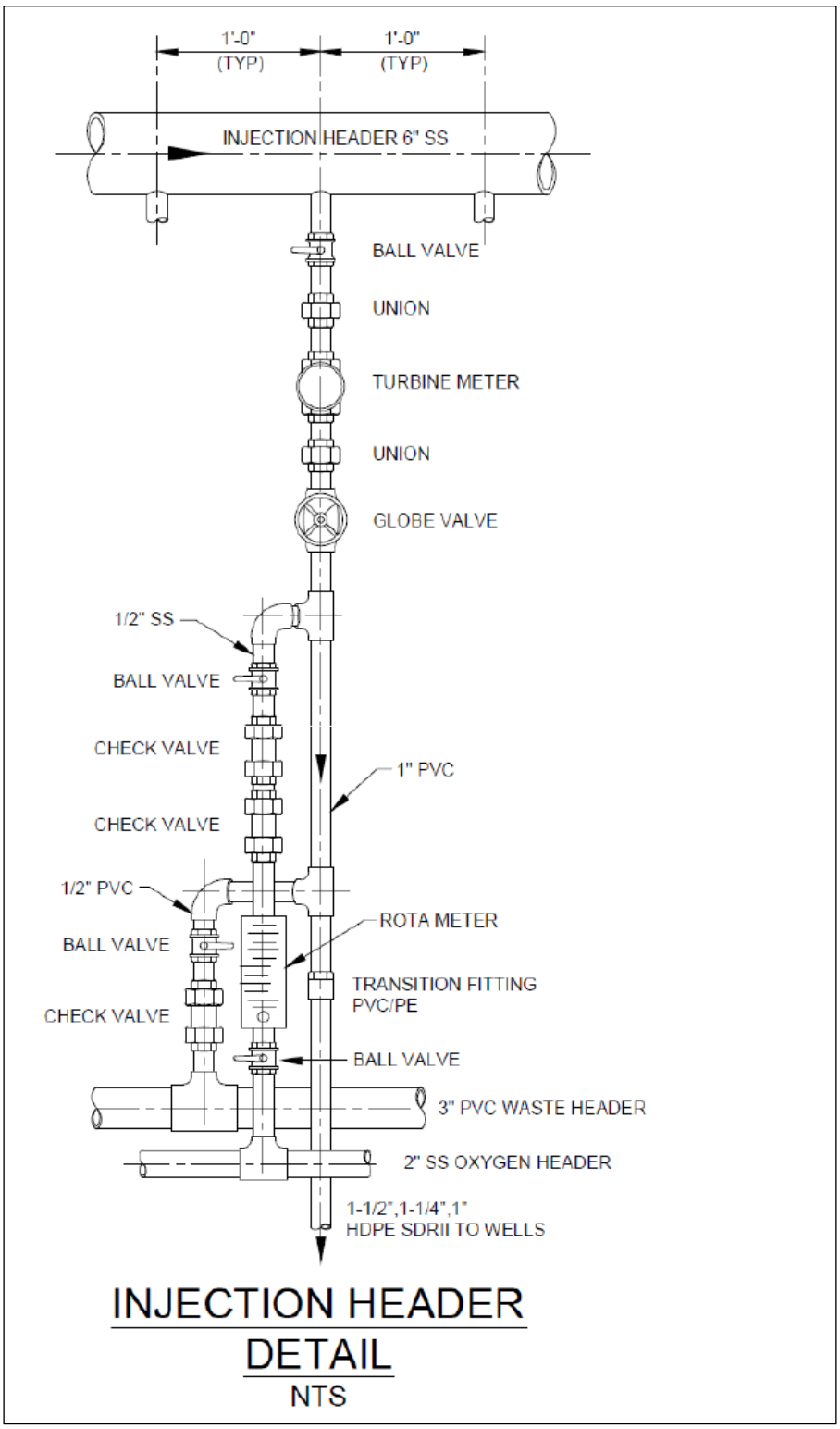


Figure7. Injection Well Header Detail



J. Wellfield Monitoring

Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity per 40 CFR § 144.51(j)(1). The following equipment must be installed in the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative sampling or measurement location:

1. a sampling port in the injectate trunkline to collect representative samples of the injectate for each wellfield;
2. instrumentation to continuously monitor and measure injectate and production flow rates for the daily recording of the injection and production flow rates for each wellfield; and
3. instrumentation to continuously monitor and measure injectate and production volumes for the monthly recording of the injection and production volumes for each wellfield.

K. Protective Automated Monitoring and Shut-off Devices

1. An instrumentation and control system must be installed to monitor pressure and flow and immediately detect and correct any anomalous condition.
2. The instrumentation and control system must meet the following requirements:
   a. Pressure and flow sensors must be installed for the purpose of leak detection on the main trunk lines connecting the Burdock Central Processing Plant and the Dewey Satellite Facility to the wellfields.
   b. Injection pressures and flow must be monitored through automated control and data recording systems that will include alarms and automatic controls to detect and control a potential release.
   c. Measurements must be collected and transmitted to both the Burdock Central Processing Plant and the Dewey Satellite Facility control systems.
   d. Alarms must be installed to provide immediate warning to operators should pressures or flows fluctuate outside of normal operating ranges to enable a timely response and implementation of appropriate action.
   e. Both external and internal shutdown controls must be installed at each header house to provide for operator safety and spill control. The external and internal shutdown controls must be designed for automatic and remote shutdown of each header house. In the event of an automatic header house shutdown, an alarm will occur and the flows of all injection and production wells in that header house will be automatically stopped. The alarm will activate a blinking light on the outside of the header house and will cause an alarm signal to be sent to the Burdock Central Processing Plant and the Dewey Satellite Facility control rooms.
   f. A control valve that will close when power is turned off or lost as a result of power failure must be used on the injection header to stop the flow to all injection wells.
   g. A pressure switch will be installed on each injection header to ensure that fluid pressure does not exceed the maximum designated injection pressure for the injection wells served by that header house. If the injection pressure reaches the maximum set value in the pressure switch, an automatic header house shutdown will occur.

PART VI. WELL WORKOVERS AND ALTERATION

A. Requirements for Well Stimulation, Workovers and Alterations

1. Well stimulations, workovers, and alterations must meet all conditions of the Permit.

2. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, and packer) or injection formation.

3. Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee must give advance notice to the Director. Any modification to well construction that is different from the approved well construction plan must be done by modification in accordance with 40 CFR § 144.39 and § 144.41.

4. The Permittee must record all work done on a Well Rework Record (EPA Form 7520-12) found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators, and must submit a revised well construction diagram, when the well construction has been modified. The Permittee must provide this and any other record of well workover, logging, or test data to the Director within thirty (30) days of the completion of the activity.

5. A successful demonstration of internal mechanical integrity is required following the completion of any well workover or alteration which affects the integrity of the casing, packer or tubing. Documentation of mechanical integrity test results must be included in the next Quarterly Monitoring Report, or sooner if the Permittee chooses. Injection operations must not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

6. If the activities were conducted within 45 days of the next Quarterly Monitoring Report, then the information must be submitted with the next Quarterly Monitoring Report.

B. Demonstration of Well Mechanical Integrity after Well Workover or Alteration

1. Following the completion of any well workover or alteration which affects the integrity of the casing or cement, the Permittee must submit to the Director a successful demonstration of internal mechanical integrity according to Part VII, Section C before recommencing injection activities into the well.
2. Injection operations must not be resumed until the Permittee has successfully demonstrated the well has mechanical integrity.
3. Documentation of mechanical integrity test results must be included in the next Quarterly Monitoring Report, or if the Permittee would like to recommence injection into the well sooner, the documentation of mechanical integrity test results may be submitted immediately to the Director.
4. If the workover is being conducted because of mechanical integrity loss, the Permittee must not resume injection until the Director has provided written approval.
5. If mechanical integrity cannot be successfully demonstrated following a workover, the well must be plugged and abandoned according to the approved plugging and abandonment plan in Part XI, Section C.

PART VII. MECHANICAL INTEGRITY

A. Definition of Mechanical Integrity

An injection well has mechanical integrity if:

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

B. Requirement to Demonstrate and Maintain Mechanical Integrity

1. The Permittee is required to ensure each injection well and production well maintains mechanical integrity at all times. Injection into a well that lacks mechanical integrity is prohibited.
2. Before the Authorization to Commence Injection is issued by the Director for each wellfield, the Permittee

must demonstrate that each wellfield injection and production well installed during development of the Injection Authorization Data Package Report has mechanical integrity according to 40 CFR § 146.8.

3. For injection and production wells constructed after the Director issues the initial Authorization to Commence Injection, the Permittee must send documentation to the Director demonstrating that each well has mechanical integrity.
4. The Permittee must receive written authorization from the Director prior to commencing operation of additional wells.
5. The Permittee must ensure the mechanical integrity tests in Table 13 are performed within the time frames specified. The internal mechanical integrity test must be performed according to the requirements in Section C of this Part. External mechanical integrity must be demonstrated according to Section D of this Part.
6. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations must be made.

Table 13. Well Testing Program

TYPE OF TEST	PURPOSE	DUE DATE
Pressure-Packer Test	To assess Internal Mechanical Integrity	Before Authorization to Commence Injection is issued for wells constructed before the wellfield pump test is conducted. For wells constructed after initial Authorization to Commence Injection, demonstration of mechanical integrity must be submitted to the Director for written approval before commencing operation. For all wellfield wells, periodically thereafter according to Part VII, Section G.
Well cementing records	To assess External Mechanical Integrity	At the completion of well construction

C. Internal Mechanical Integrity Test

1. Prior to initiation of injection activities in a wellfield, all injection, production, and monitoring wells must be field tested to demonstrate the mechanical integrity of the well casing.
2. The mechanical integrity of the well casing must be demonstrated using a pressure-packer test.
3. If the testing pressure drops less than 10 percent during the 10-minute test, the well casing has demonstrated acceptable mechanical integrity.
4. The Permittee must conduct the pressure-packer test procedure as follows:
   a. Seal bottom of the casing with a plug, downhole inflatable packer, or other suitable device.
   b. Fill the casing with water.
   c. Seal the top of the casing with a threaded cap, mechanical seal or downhole inflatable packer.
   d. Apply an induced pressure on the water column within the well casing using water or compressed gas.
   e. Monitor induced pressure with a calibrated pressure gauge.
   f. Increase induced pressure to 125% of the maximum operating pressure of the well field or 125% of the maximum operating pressure rating of the well casing, whichever pressure value is lower.

5. A well must maintain at least 90 percent of this pressure for a minimum of 10 minutes to pass the test.
6. If there are obvious leaks, or the pressure drops by more than 10 percent during the 10-minute period, the Permittee must check and/or reset the seals and fittings on the packer system and conduct another test.

D. Demonstration of External Mechanical Integrity

1. The well construction report must include detailed cementing records documenting that the requirements under Part V, Section E were met to demonstrate the absence of significant fluid movement through the well borehole-casing annulus.
2. Because this Area Permit is allowing cementing records to demonstrate external mechanical integrity, the monitoring program requirements in Part IX must be designed to verify the absence of significant fluid movement outside the injection interval through confining zones as required under 40 CFR § 146.8(c)(4).
3. The Director may require the Permittee to conduct remedial cementing between the well casing and the borehole wall if the well construction report cannot verify that the requirements under Part V, Section E were met.

E. Reporting Results of Initial Mechanical Integrity Demonstrations

The results of initial mechanical integrity tests must be submitted to the Director as required in Part IX, Section E.6.

F. Requirement to Plug and Abandon any Injection, Production or Monitoring Well for which Mechanical Integrity Cannot Be Demonstrated

1. If mechanical integrity cannot be demonstrated for any injection, production, or monitoring well after workovers and remedial actions have been performed, the Permittee must plug and abandon those wells according to the requirements under Part XI.
2. The Permittee must include these activities in the report on initial mechanical integrity demonstrations.

G. Ongoing Demonstration of Mechanical Integrity

1. After initial demonstration of mechanical integrity required in Sections B.2 and B.3 of this Part, the Permittee must demonstrate internal mechanical integrity of each injection well within five (5) years of the last successful mechanical integrity test even if the well is not active. The procedure and criteria for demonstrating internal mechanical integrity are found in Section C.4 of this Part.
2. Results of mechanical integrity tests must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless the mechanical integrity test occurred within 45 days before the due date of the Quarterly Monitoring Report. In that case, the mechanical integrity test results must be submitted with the following Quarterly Monitoring Report.
3. Failing to provide the Director with a successful demonstration of mechanical integrity in a timely manner will be a violation of this permit.
4. **Demonstration of External Mechanical Integrity**
   Because the well cementing record in the well construction report must be used to demonstrate external mechanical integrity as required under Section D of this Part, no repeat test is required.
5. **Demonstration of Mechanical Integrity after Well Workovers**
   In addition to these regularly scheduled demonstrations of mechanical integrity, the Permittee must demonstrate internal mechanical integrity following any workover that affects the integrity of the casing or cement of any injection or production wells within a wellfield as required under Part VI, Section B. The

Permittee must not resume injection after a well workover until the Director has issued writing approval to resume injection.

6. Additional or Alternative Mechanical Integrity Tests

The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director for demonstrating there is no movement of fluid into or between USDWs resulting from injection activity.

H. Notification Prior to Testing

Except for the initial mechanical integrity test required before injection or production well operation, the Permittee must notify the Director at least seven calendar days prior to any regularly scheduled mechanical integrity test. When the mechanical integrity test is conducted after well construction, well conversion, or a well rework, any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

I. Loss of Mechanical Integrity

1. If an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as increase in flow rate measured at injection well header or water flowing at the surface, etc.), the Permittee must notify the Director within 24 hours (see Part XII, Section D.10.e of this Permit), and the well must be shut-in within 48 hours unless the Director requires immediate shut-in.
2. Upon discovering that an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation, as soon as practically possible, the Permittee must collect water level measurements from the nearest monitoring wells in overlying aquifers and compare them to the previously collected water level data. If an increase in water level is observed, then the Permittee must collect fluid samples from the nearest monitoring wells in overlying aquifers, analyze the samples for excursion parameters and compare the data to previous analyses for these wells. If an excursion is confirmed according to Part IX, Section C.3, then the Permittee must follow the monitoring requirements under Part IX, Section C.4.
3. Within five days of when the loss of mechanical integrity became evident, the Permittee must submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan and the results of the recent monitoring well data required under 2 above that are available at the time of the five-day report.
4. Injection operations must not be resumed until after the Permittee has:
    i. has successfully repaired the well,
    ii. demonstrated the well has mechanical integrity,
    iii. demonstrated that monitoring for an excursion has occurred as required under Section I.2 under this Part and any excursion confirmed according to Part IX, Section C.3 resulting from the mechanical integrity loss is being addressed according to Part IX, Section C.4, and
    iv. received written approval to resume injection from the Director.

PART VIII. WELL OPERATION

The Permittee must adhere to the following requirements prior to and during injection and production well operation.

A. Injection between the outermost casing protecting USDWs and the well bore is prohibited.

B. The migration of ISR contaminants across the aquifer exemption boundary into USDWs is prohibited. The constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. The permit limit for each constituent is either the permit limit listed in Appendix B, Table B-1 or the or the aquifer background concentration as determined according to Part II, Section E.2.b.iv, whichever value is higher.

C. Requirements Prior to Commencing Injection in a Wellfield

1. General Requirements

The Permittee must not commence injection until:

a. Well construction is complete;
b. The well construction report is complete;
c. The Permittee has submitted the Injection Authorization Data Package Report described in Part II, Section H;
d. Initial demonstration of mechanical integrity pursuant to 40 CFR § 146.8 and Part VII, Sections B.2 and B.3 has been successful and documented; and
e. The Director has issued the written Authorization to Commence Injection.

2. Confirmation of Aquifer Baseline Potentiometric Surface

a. After the wellfield pump test has been completed and the static potentiometric surface for each aquifer has stabilized from the wellfield pump test, the static potentiometric water levels must be measured in every well in the monitoring system prior to the initiation of injection into the wellfield to determine the degree to which the injection interval potentiometric surface has recovered after the wellfield pump tests.
b. At that time the baseline static potentiometric surface for each aquifer must be established, along with a range of water level variance to be expected due to barometric pressure change, for comparison against operational water level measurements.

D. Injection Interval

1. Injection is authorized only within the approved vertical interval of the Inyan Kara aquifers.
2. Injection intervals and well screen or open hole intervals will be authorized only within the exempted portion of the Inyan Kara aquifer.
3. Well screen or open hole injection intervals must be determined based on results of wellfield delineation drilling and logging and injection and production well logging to determine the vertical thickness of the ore deposits.

E. Injection Pressure Limitation and MAIP Compliance Point

1. The Permittee must use a pressure gauge located either at each wellhead or at the injection manifold at each header house as the compliance point at which the MAIP is demonstrated not to exceed the permit limit set according to Part V, Section F.6.

2. The Permittee may use pressure gauges at the injection manifold only after verification that the injection pressure measured at the header house pressure gauge is greater than or equal to the injection pressure measured at the wellhead of each injection well connected to the header house as described under Part V, Section I.1.

F. Hydraulic Control of Wellfield

1. The Permittee must maintain hydraulic control of each wellfield from the initiation of injection through the end of groundwater restoration.
2. During ISR operation in each wellfield, the production wells must pump a larger volume of fluids out of the wellfield than the injection wells are injecting to maintain a hydraulic gradient directed inward toward the wellfield.
3. During post-ISR groundwater restoration, pumping wells must extract a greater volume of groundwater than the injection wells are pumping into the wellfield to maintain the inward hydraulic gradient.

4. Hydraulic Control of Wellfield during ISR Operation

a. During uranium recovery, the groundwater removal rate in each wellfield must exceed the lixiviant injection rate, creating a cone of depression within each wellfield.
b. This condition must be verified by:
    i. monitoring water levels in the injection interval perimeter monitoring wells that are below the baseline water levels established under Section C.2 of this Part the majority of the time;
    ii. continuous monitoring of injection and production flow rate and volume and
    iii. daily recording of flow rate of injection and production fluids for each wellfield.

5. Hydraulic Control of Wellfield during Groundwater Restoration

a. The Permittee must maintain hydraulic control of each wellfield until groundwater restoration has been completed through intermittent or continuous pumping of groundwater from the wellfield.
b. Hydraulic control must be verified by monitoring water levels in the injection interval perimeter monitoring wells that are consistently below the baseline water levels established under Section C.2 of this Part.
c. The Permittee must monitor the water levels in the wellfield perimeter monitoring well ring in accordance with the requirements in Part IX, Section B.1.e, Table 14.F and Part IX, Section C.

6. Notification of Completion of Groundwater Restoration

a. The Permittee must notify EPA in the next Quarterly Monitoring Report once groundwater restoration is completed for a wellfield.
b. At that time the requirement to maintain hydraulic wellfield control for the wellfield is no longer applicable.
c. However, the monitoring requirement for measuring water levels in all perimeter wellfield monitoring wells must be continued in order to verify the return of the natural groundwater gradient in the wellfield area.
d. Monitoring the water levels in the non-injection interval monitoring wells in overlying aquifer units must be conducted as required in Part IX, Section C until wellfield post-restoration stability monitoring is completed.

G. Injection Flow Rate and Injectate Volume

Because of the net extraction of groundwater within the wellfield during injection activities, there is no injection volume limit requirement in this Area Permit.

H. Injection Fluid Limitation

1. During the ISR process, the injection fluid is limited to ISR lixiviant consisting of wellfield groundwater with carbon dioxide and oxygen added.
2. During the groundwater restoration phase, the injectate will be limited to permeate from reverse osmosis (RO) treatment of groundwater extracted from the post-ISR wellfields, clean makeup water or groundwater recirculated within the wellfield.
3. Chemical reductant may be injected for the purposes of aquifer remediation after written authorization by rule from the Director.
4. If the Permittee determines that injection is required for groundwater restoration either within the wellfield or outside the wellfield due to an excursion or to inject a groundwater tracer, the Permittee must submit an authorization by rule proposal to the Director.

I. Tubing-Casing Annulus

The approved well construction design does not include requirements for a packer to seal off the annulus between the tubing and casing. There are no permit requirements under this section for the annulus between the well casing and the injection tubing. (The injection tubing is called the injection piping under Part V, Section E.3.)

PART IX. MONITORING, RECORDING AND REPORTING OF RESULTS

A. General Monitoring Requirements

1. Because this Area Permit allows cementing records to be used to demonstrate the absence of significant fluid movement to fulfill the external mechanical integrity demonstration requirement as described under Part VII, Section D, the monitoring program required under Section B of this Part must be designed to verify the absence of significant fluid movement through the confining zones per 40 CFR § 146.8(c)(4).
2. Monitoring observations, measurements, fluid samples, etc. taken for the purpose of complying with these requirements must be representative of the activity or condition being monitored.
3. Fluid samples collected for the purpose of compliance with the conditions of this Area Permit must be tracked and controlled using a Chain of Custody to verify the analytical results are applicable to the identified fluid sample.
4. To ensure that groundwater samples are representative of ambient groundwater conditions surrounding the well, groundwater samples must be collected according to the procedures in Part II, Sections E.2.b.
5. Fluid samples collected for the purpose of compliance with this Area Permit must be handled according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*.
6. Operating parameters must be observed and recorded under normal operating conditions, and all parameters must be observed simultaneously to provide a clear depiction of well operation.
7. All monitoring equipment to be installed, maintained and used according to manufacturer's directions and any applicable operating manuals.
8. Any equipment calibration must be conducted as specified by the manufacturer at the frequency specified by the manufacturer. Documentation of calibration must include the name of the person performing the

calibration and the date of calibration.

9. Required monitoring including type, intervals, and frequency must be sufficient to yield data which are representative of the monitored activity including when appropriate, continuous monitoring.
10. Pressures are to be measured in pounds per square inch (psi).
11. Fluid volumes are to be measured in gallons.
12. Fluid rates are to be measured in gallons per minute (gpm).

B. Monitoring Parameters, Frequency, Records and Reports

Monitoring parameters and frequency are specified in Section 1 below.

1. Monitoring Parameters and Frequency

a. Monitoring information is to be collected, recorded and reported for all parameters at the frequency indicated, even during periods when the well is not operating.
b. Injection pressure must be continuously monitored at the pressure gauges installed on each header house injection manifold and manually recorded at least daily for each header house.
c. The injection and production flow rates must be continuously monitored for each wellfield and must be recorded daily from monitoring devices at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1) requirement that samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.
d. Monthly injection and production volumes must be continuously monitored and recorded for each wellfield from monitoring performed at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1) requirement that samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.
e. Parameters must be monitored and recorded as indicated in Table 14.
f. Monitoring information and results must be included in the Quarterly Monitoring Report.
g. Representative samples of the injectate for each wellfield must be collected and analyzed monthly for the analytes listed in Table 15.
h. The analytical methods included in Table 15 must be used for injectate sample analysis. Equivalent methods may be used after prior approval by the Director.

Table 14. Monitoring Parameters and Frequency

A. CONTINUOUSLY	
MONITOR	Injection Pressure (psig) at each header house
	Injection Rate (gpm) for each wellfield at injection trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1). Production rate (gpm) for each wellfield at production trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1).
	Injection volume (gallons) for each wellfield at injection trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1). Production volume (gallons) for each wellfield at production trunkline at the Burdock

	Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1).
B. DAILY	
OBSERVE AND RECORD	Injection Pressure (psig) at each header house (or each wellhead if Part V, Section I.2.g is used) Injection Flow Rate for each wellfield Production Flow Rate for each wellfield
C. WEEKLY EXCURSION MONITORING OF WELLS WHEN EXCURSION IS CONFIRMED	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels for impacted wells and the two adjacent non-impacted wells Impacted wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from monitoring wells described above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
D. 14-DAY INTERVAL EXCURSION MONITORING DURING ISR OPERATION	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels Wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from each well listed above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
E. MONTHLY	
RECORD	Monthly Average, Maximum, and Minimum values for Injection Pressure (psig)
	Maximum, minimum and average values for Daily Injection Rate (gpm) for each wellfield
	Maximum, minimum and average values for Daily Production Rate (gpm) for each wellfield
	Injected volume for that month (gallons) for each wellfield
	Produced volume for that month (gallons) for each wellfield
ANALYZE	Injectate flowing to each wellfield for parameters in Table 15 Expanding excursion monitoring well samples for water quality constituents in Table 8 per Part IX, Section C.4.g.
REPORT	Next scheduled Quarterly Report
F. 60 DAY INTERVAL EXCURSION MONITORING DURING GROUNDWATER RESTORATION AND POST-RESTORATION STABILITY MONITORING	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels Wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from each well listed above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
G. QUARTERLY	
ANALYZE	Samples from operational monitoring stock wells within permit area for chloride, total alkalinity, and specific conductance Samples from operational monitoring of domestic wells for excursion parameters, except for

	the annual sampling event that coincides with the NRC License requirement.
REPORT	Monthly Average, Maximum, and Minimum values for Daily Injection Pressure (psig)
	Monthly Average, Maximum, and Minimum values for Daily Injection Rate (gpm)
	Monthly Average, Maximum, and Minimum values for Daily Production Rate (gpm)
	14-day interval excursion monitoring results during ISR operation
	Injection volume for each wellfield for each month during the quarter (gallons)
	Production volume for each wellfield for each month during the quarter (gallons)
	Monthly Results of injectate fluid analysis in units listed in Table 15
	Summary of seismic events measuring 2.0 magnitude on the Modified Mercalli Intensity (MMI) scale or greater occurring within a fifty (50) mile radius of the Area Permit boundary.
	Well construction reports and initial mechanical integrity test results for new injection, production and monitoring wells
	Initial header house injection pressure verification reports
	60-day interval excursion monitoring results during groundwater restoration and post-restoration stability monitoring
	Quarterly sampling results from Operational Monitoring Wells
	Quarterly Operational Groundwater Monitoring sample results from domestic wells.
	Results from Post-operational groundwater samples per Part IX, Section B.3 as applicable.
	Results from Post-restoration stability monitoring samples per Part IX, Section B.4 as applicable.
	Weekly excursion monitoring of wells when excursion is confirmed
H. 24-HOUR REPORTING	
REPORT	Upon discovery that an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation as described under Part VII, Section I.
	Injection pressure measured above the MAIP for a header house.
	If any seismic event measuring 4.5 magnitude (MMI scale) or greater is reported within two miles of the permit boundary per Part IX, Section D.
	Any noncompliance which may endanger human health or the environment, including: • Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or • Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.
	Initial excursions as described in Part IX, Section E.9.a.
	An expanding excursion plume as described in Part IX, Section E.9.d
	Discovery that excursion indicator concentrations are increasing in excursion-impacted monitoring wells as described in Part IX, Section E.9.d.
	Upon discovery of any other noncompliance as described in Part XII, Section D.10.e.

I. ANNUALLY	
ANALYZE	Operational Monitoring samples from domestic wells for NRC list of analytes.
REPORT	Analytical results for Operational Monitoring samples from domestic wells.
	AOR update per Part V, Section H for each year construction is delayed at the Project Site

Table 15. Injection Fluid Characterization Parameters

Analyte	Reporting Units	Analytical Methods
Physical Properties		
pH	pH units	A4500-H B
Total Dissolved Solids	mg/L	A2540 C
Specific conductance	µmhos/cm	A2510B or E120.1
Specific Gravity	Ratio to density of water	ASTM D1429-13, SM 2710F
Commons Elements and Ions		
Alkalinity (as $CaCO_3$)	mg/L	A2320 B
Chloride	mg/L	A4500-Cl B; E300.0
Sulfate	mg/L	A4500-SO4 E; E300.0
Dissolved Metals		
Arsenic	mg/L	E200.8
Iron	mg/L	E200.7
Lead	mg/L	E200.8
Manganese	mg/L	E200.8
Selenium	mg/L	E200.8
Strontium	mg/L	E200.8
Uranium	mg/L	E200.7; E200.8
Vanadium	mg/L	E200.7; E200.8
Radionuclides		
Gross Alpha	pCi/L	E900.0
Gross Beta	pCi/L	E900.0
Radium -226	pCi/L	E903.0
Radium -228	pCi/L	E903.0

2. Operational Groundwater Monitoring

a. Domestic Wells

i. During operations, the Permittee must monitor all downgradient domestic wells within 1.2 miles of the boundary of each wellfield (as measured from the perimeter monitoring well ring), unless the well owners do not consent to sampling or the condition of the wells renders a well unsuitable for sampling.

ii. Wells to be monitored under this requirement are shown in Figure 8.

iii. Samples must be collected quarterly and analyzed for the three excursion parameters, except for the sample collected at the time of the annual monitoring sample required under the NRC license. The annual sample must be analyzed for the analytes in Table 5.7-2: *List of Baseline* Parameters in the NRC Safety Evaluation Report.

b. Stock Wells

i. During the design of each wellfield, all stock wells within ¼ mile of the perimeter monitoring well ring must be evaluated for the potential to be adversely affected by ISR operations or to adversely affect ISR operations.

ii. During operation, the Permittee must monitor all stock wells located within the project boundary (Figure 9) that were not plugged and abandoned due to impact on ISR operations.

iii. Samples must be collected quarterly and analyzed for water level and the three excursion indicators: chloride, total alkalinity, and specific conductance.

c. Monitoring Wells

i. The Permittee must monitor wells located hydrologically up-gradient and downgradient of ISR operations as part of the operational groundwater monitoring program.

ii. Monitoring wells included in the operational monitoring program must include wells completed in the alluvium, Fall River, Chilson, and Unkpapa aquifers.

iii. The proposed wells indicated in Table 16 (Well ID is TBD) and in Figures 10 and 11 must be installed before the first wellfield pump test is conducted in the Burdock Area.

iv. The monitoring wells must be monitored quarterly and analyzed for the water quality parameters listed in Table 8.

d. The operational monitoring well locations are shown in Figures 8 through 12 and are listed in Table 16.

Table 16. Monitoring Wells Included in Operational Monitoring Program

Well ID	Qrt- Qrt		Section	Township	Range	Relative Position
	Alluvium					
676	SESW		34	6S	1E	Burdock/Downgradient of land application
677	SWSW		4	7S	1E	Dewey/Downgradient near Beaver Creek
678	SWNE		9	7S	1E	Downgradient of Site Boundary
679	NWSE		27	6S	1E	Burdock/Up-gradient
707	SWNE		34	6S	1E	Burdock/Downgradient of Triangle Pit
708	SESW		3	7S	1E	Burdock/Downgradient of land application
709	SENW		15	7S	1E	Burdock/Downgradient of wellfields
DC-1	NWSW		30	6S	1E	Dewey/Up-gradient
DC-2	SESW		30	6S	1E	Dewey/Downgradient of land application
DC-3	NWNE		31	6S	1E	Dewey/Downgradient of wellfield
DC-4	NWNW		32	6S	1E	Dewey/Downgradient of wellfield
	Fall River					
631	SWSW		23	6S	1E	North of Site Boundary/Up-gradient
681	NENW		32	6S	1E	Dewey/Production Zone
688	NESW		11	7S	1E	Burdock/Overlying Production Zone
694	NWNW		15	7S	1E	Burdock/Downgradient
695	SESE		32	6S	1E	Dewey/Downgradient
698	NESW		2	7S	1E	Burdock/Downgradient
706	NENE		21	6S	1E	North of Project Site/Up-gradient
TBD	SWNE		34	6S	1E	Burdock/Downgradient of Triangle Pit
TBD	NWSE		2	7S	1E	Burdock/Downgradient of Darrow Pit
	Chilson					
43	SWSE		34	6S	1E	Burdock/Downgradient of Triangle Pit
680	NESW		11	7S	1E	Burdock/Production Zone
689	NENW		32	6S	1E	Dewey/Production Zone
696	NWNW		15	7S	1E	Burdock/Downgradient
697	SESE		32	6S	1E	Dewey/Downgradient
705	NENE		21	6S	1E	North of Project Site/Up-gradient
3026	SESE		1	7S	1E	Burdock/Up-gradient
TBD	SWSE		2	7S	1E	Burdock/Downgradient of Darrow Pit
	Unkpapa					
690	NESW		11	7S	1E	Burdock/Underlying Production Zone
693	NENW		32	6S	1E	Dewey /Underlying Production Zone
703	SWSE		1	7S	1E	Burdock/At Up-gradient Edge of Wellfield

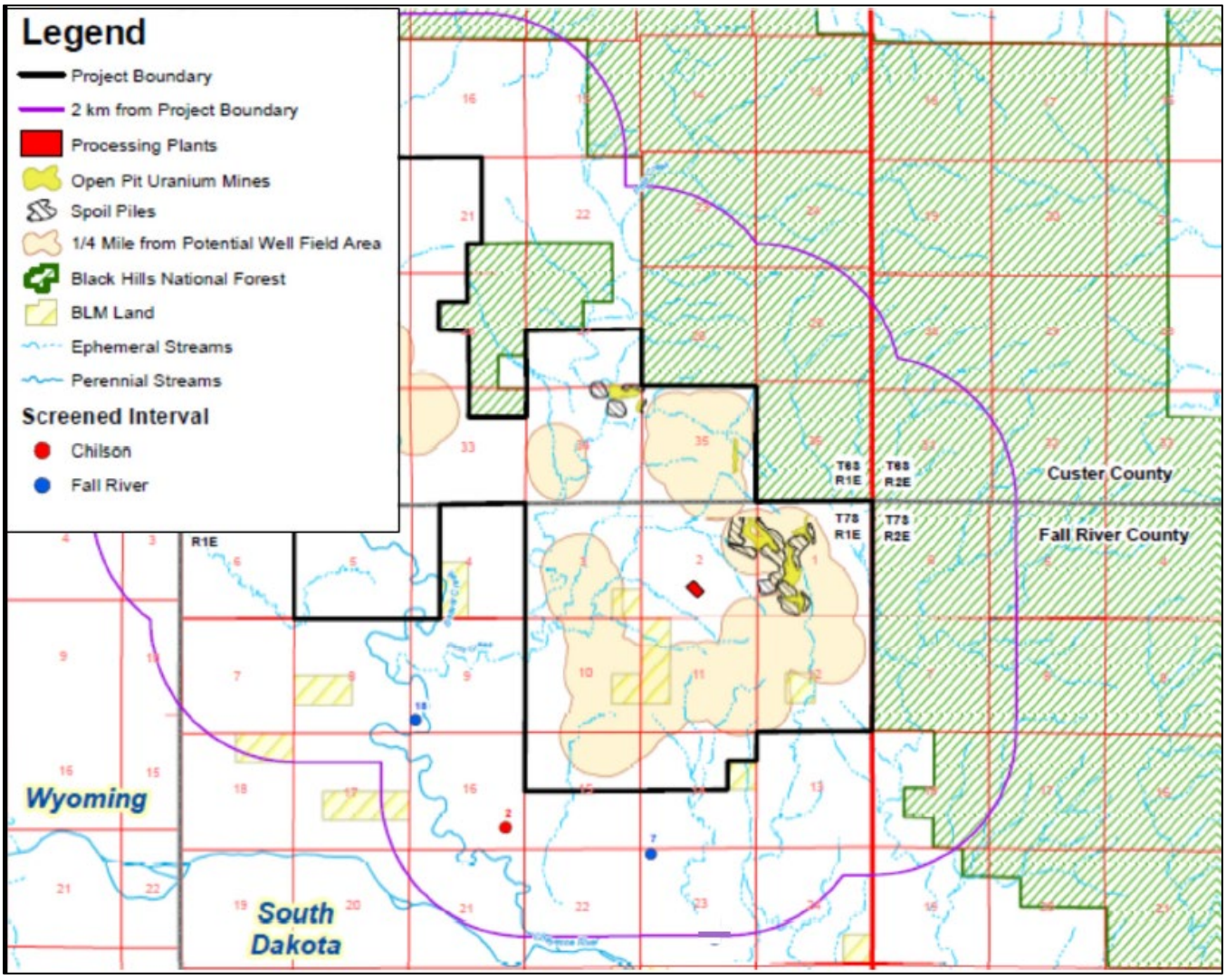


Figure 8. Operational Monitoring Wells – Three Domestic Wells: Hydro IDs 2, 7 and 18

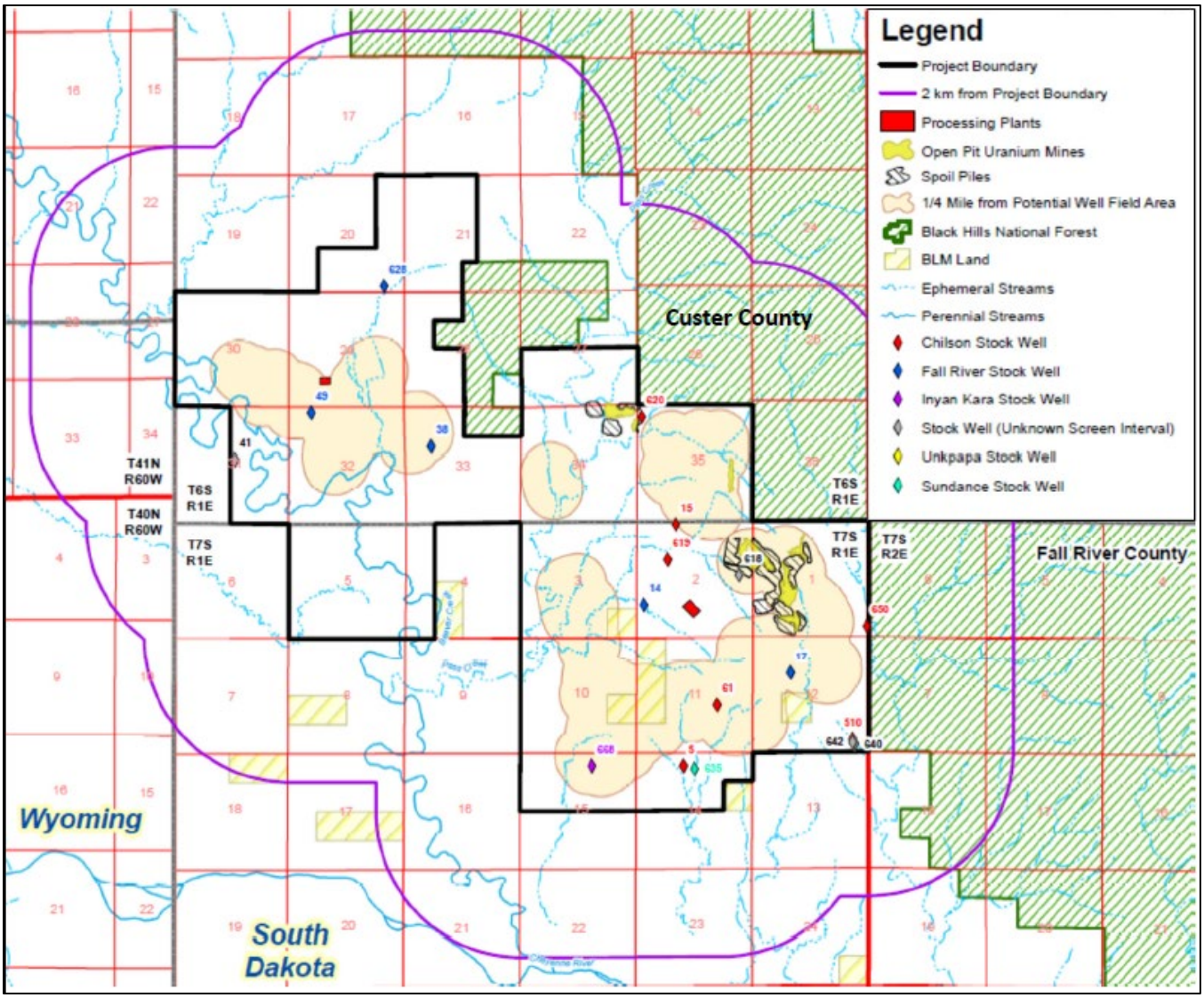


Figure 9. Operational Monitoring Wells - Stock Wells

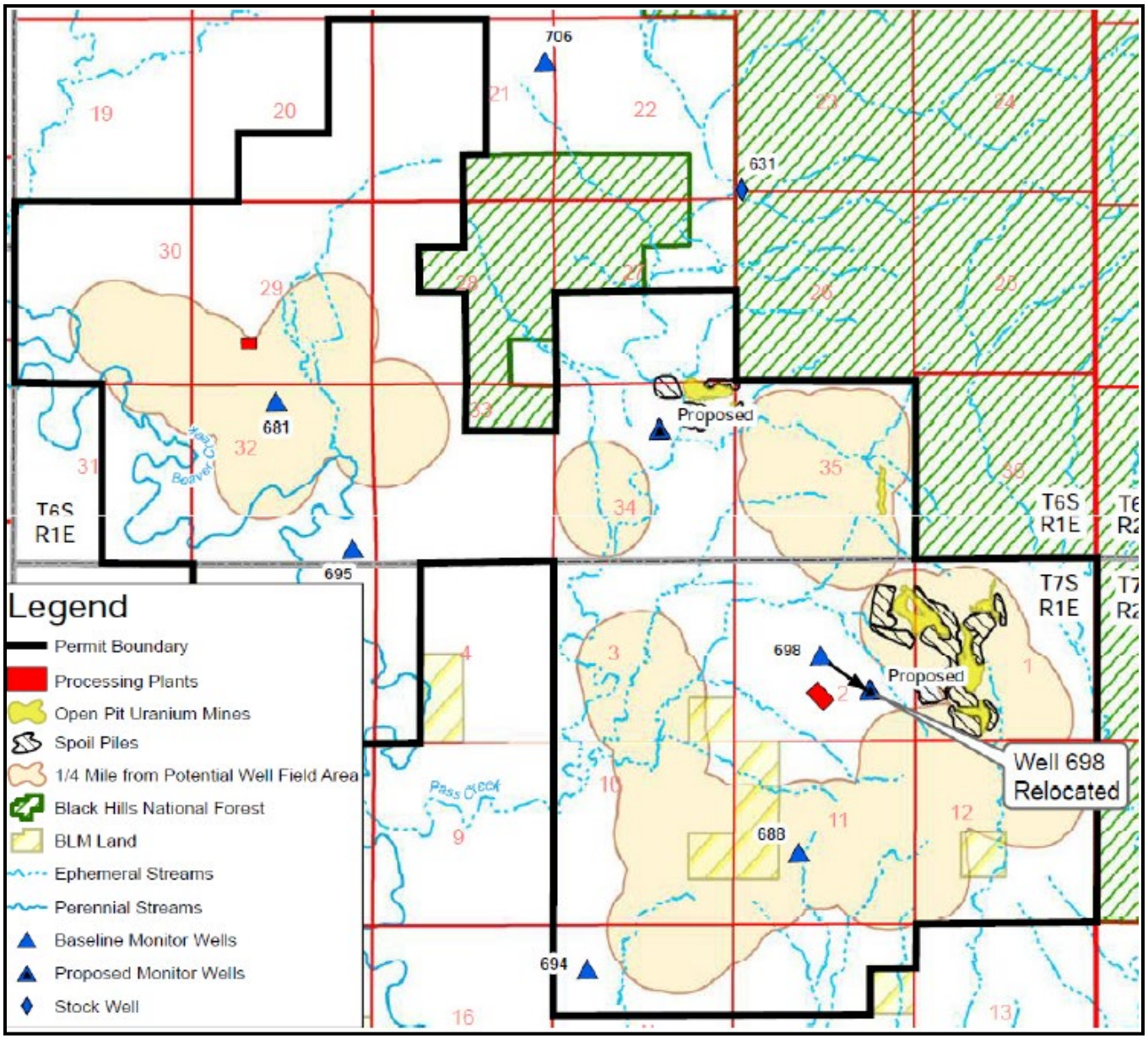


Figure 10. Fall River Operational Monitoring Wells

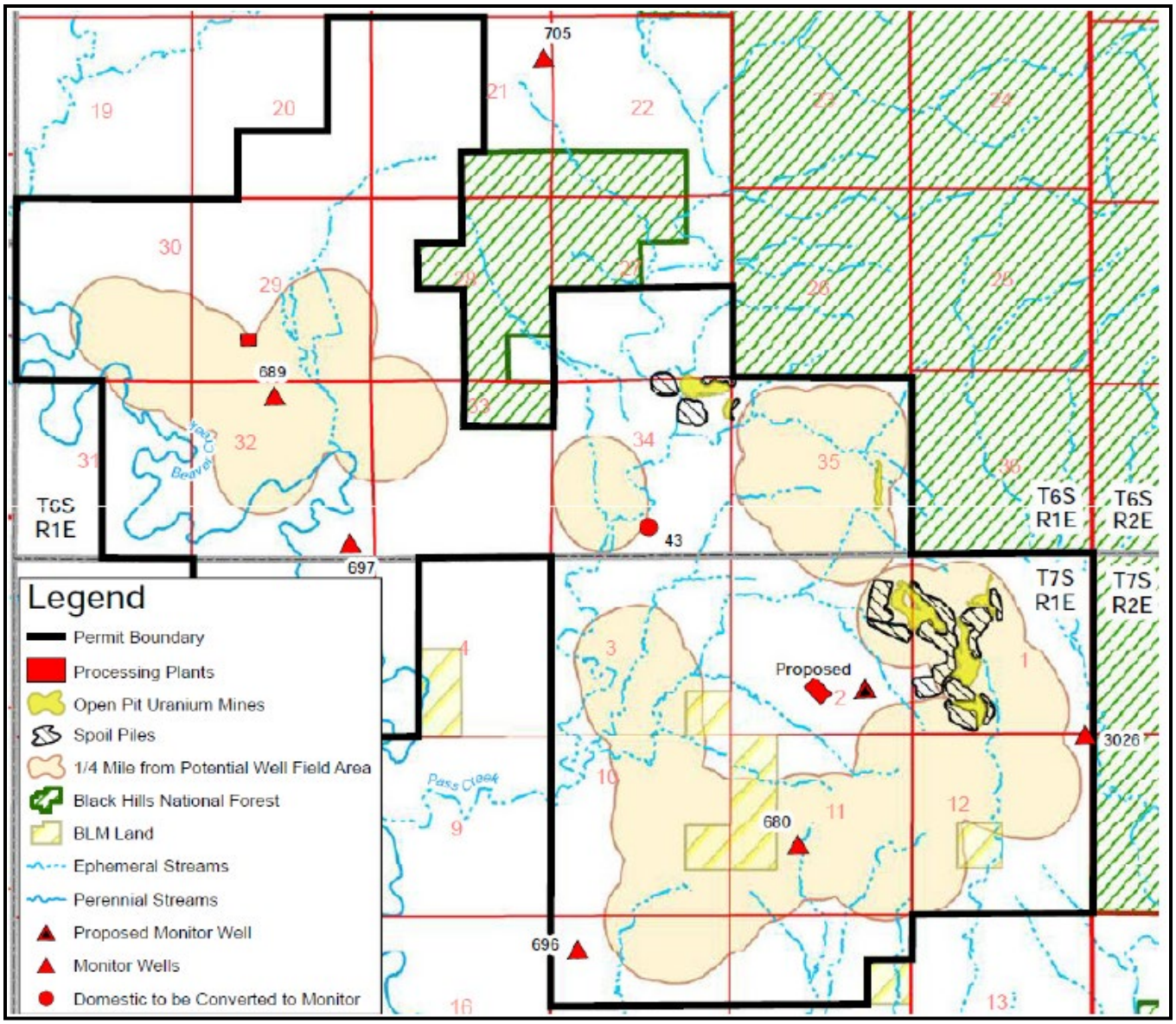


Figure 11. Chilson Operational Monitoring Wells

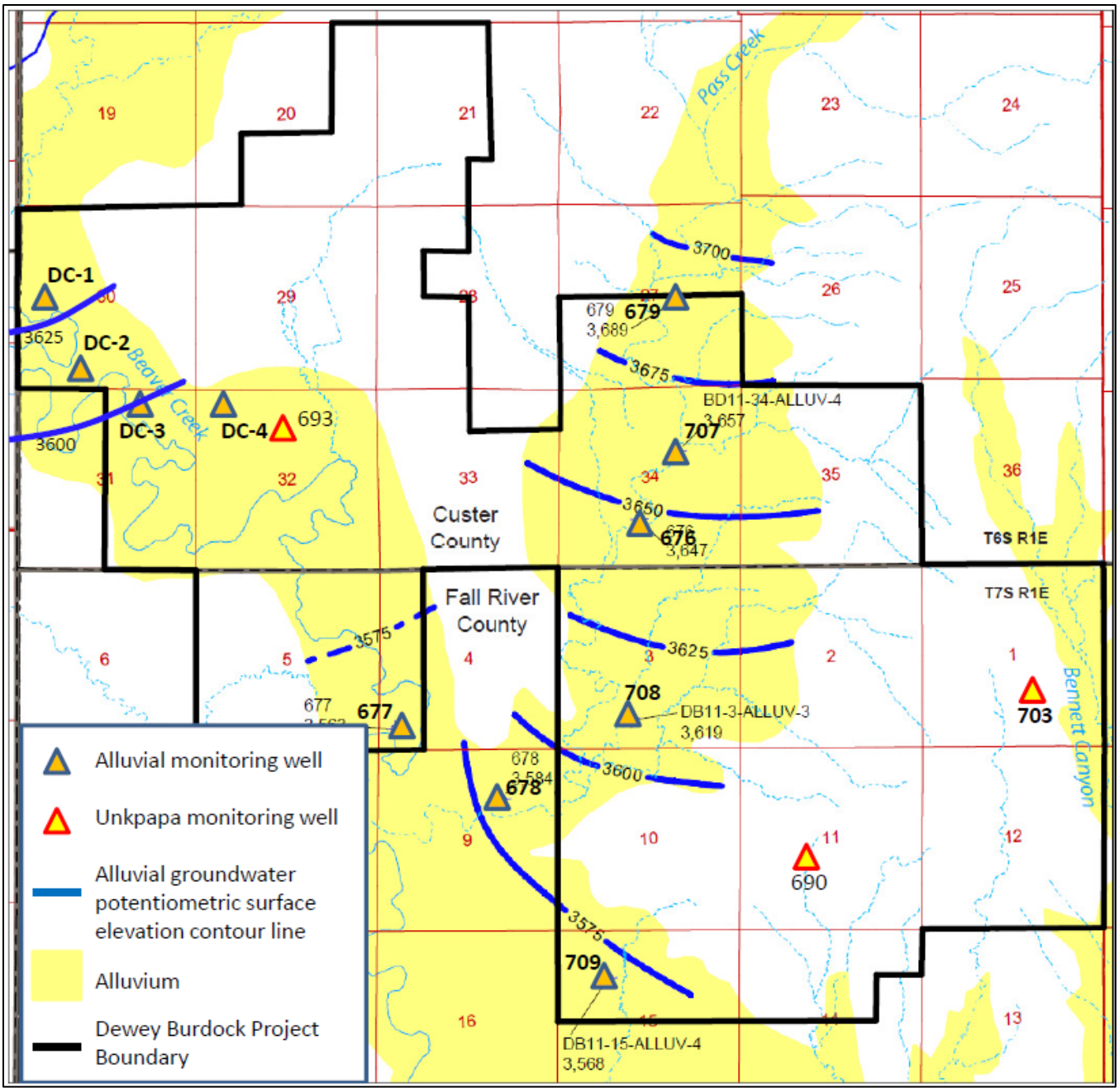


Figure 12. Unkpapa and Alluvial Operational Monitoring Wells

3. **Post-Operational Groundwater Monitoring**
   a. After completing ISR operations and prior to initiating the wellfield restoration process, groundwater samples may be collected at the Permittee's discretion from the wellfield injection interval wells used to determine Commission-approved background concentrations as discussed under condition 11.3 of the NRC license and analyzed for parameters listed in Table 8, including radium-228.
   b. Any ISR contaminant listed in Appendix B, Table B-1 having a concentration at or below the permit limit or the groundwater background concentration at all injection interval wells within the wellfield may be excluded from geochemical modeling described under Part IV, Section B of this Permit.
   c. If radium-228 is not detected in a well, then this parameter may be omitted from the analyte list for analysis of subsequent samples from that well.

4. **Post-Restoration Stability Monitoring**
   a. Groundwater samples must be collected quarterly from injection interval wells used to determine Commission Approved Background concentrations as discussed under condition 11.3 of the NRC license and analyzed for parameters listed in Table 8.
   b. Additional samples must be collected as necessary for evaluation of any areas with high contaminant concentrations.

5. **Monitoring records must Include:**
   a. Chain of Custody for fluids samples
   b. The date, exact place, and time of sampling or measurements;
   c. The individual(s) who performed the sampling or measurements;
   d. The date(s) analyses were performed;
   e. The individual(s) who performed the analyses;
   f. The analytical techniques or methods used; and
   g. The results of such analyses.

C. Excursion Monitoring

1. **During ISR Operations**
   a. **Groundwater Level Measurements:** Monitoring for excursions during ISR operations must consist of measuring water levels in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells twice a month and no more than 14 days apart in any given month.
   b. **Groundwater Sampling and Analysis:** Groundwater samples must be collected from injection interval wellfield perimeter monitoring well and non-injection interval monitoring wells and analyzed for chloride, total alkalinity and specific conductance twice a month and no more than 14 days apart in any given month.
2. **During Groundwater Restoration and Post-Restoration Stability Monitoring**
   a. **Groundwater Level Measurements:** Monitoring for excursions during groundwater restoration and post-restoration stability monitoring must consist of measuring water levels in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells every 60 days**.**
   b. **Groundwater Sampling and Analysis:** Groundwater samples must be collected from injection interval wellfield perimeter monitoring well and non-injection interval monitoring wells and analyzed for the excursion parameters: chloride, total alkalinity and specific conductance every 60 days.

3. **Criteria for Confirmation of an Excursion**

   If the concentrations of any two excursion indicator parameters exceed their respective Upper Control Limit (UCL) , as established under the NRC License, or any one excursion indicator parameter exceeds its UCL by 20 percent, the excursion criterion is exceeded and a verification sample must be taken from that well within 48 hours after results of the first analyses are received. If the verification sample confirms that the excursion criterion is exceeded, the well must be placed on excursion status. If the verification sample does not confirm that the excursion criterion is exceeded, a third sample must be taken within 48 hours after the results of the verification sample are received. If the third sample shows that the excursion criterion is exceeded, the well must be placed on excursion status. If the third sample does not show that the excursion criterion is exceeded, the first sample will be considered an error and routine excursion monitoring will be resumed (the well is not placed on excursion status).

4. **During a Confirmed Excursion Event**

   a. **Notify the Director within 24 hours:** If an excursion has been confirmed under Section C.3 of this Part, the Permittee must notify the Director within 24 hours of receiving the confirmation sampling results.

   b. **Groundwater Level Measurements:** For an excursion event that has been confirmed according Section C.3 above, monitoring must consist of measuring the water levels every seven (7) days in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells impacted by the excursion.

   c. **Groundwater Sampling and Analysis:** Groundwater samples must be collected every seven (7) days from all impacted wellfield monitoring wells and analyzed for the excursion parameters: chloride, total alkalinity and specific conductance.

   d. **Monitoring Nearest Unimpacted Wellfield Perimeter Monitoring Wells:** For injection interval excursions impacting wellfield perimeter monitoring wells, the nearest injection interval wellfield perimeter monitoring wells on each side of the impacted well(s) that have not been impacted by the excursion must also be monitored weekly according to Sections C.4.**a** and C.4.**b** above to verify that the excursion plume is not expanding.

   e. **Criteria for Expanding Excursion Plume:**

      i. If excursion monitoring shows that an adjacent unimpacted wellfield perimeter monitoring well or an adjacent unimpacted non-injection interval monitoring well becomes impacted by an existing excursion, the excursion is now considered to be an expanding excursion plume.

      ii. Even if no adjacent monitoring wells are impacted by an existing excursion as described in Section 4.e.***i*** above, if excursion monitoring shows increasing concentrations in excursion parameters over four consecutive sampling periods, the excursion is now considered to be an expanding excursion plume.

   f. **Verification Actions for Expanding Excursion Plume:**

      i. A verification sample must be taken from the newly impacted adjacent well(s) within 48 hours after results of the first analyses are received.

      ii. If the verification sample confirms that the excursion criterion is exceeded, the well must be placed on excursion status and the excursion is considered to be an expanding plume. The Permittee must conduct the activities required under Section C.5 of this Part below.

      iii. If the verification sample does not confirm that the excursion criterion is exceeded, a third sample must be taken within 48 hours after the results of the verification sample are received. If

the third sample shows that the excursion criterion is exceeded, the well must be placed on excursion status and the excursion is considered to be an expanding plume.

iv. If the third sample does not show that the excursion criterion is exceeded, the first sample will be considered an error. Routine weekly excursion monitoring must continue but the well is not placed on excursion status and the excursion is not considered to be an expanding excursion plume.

g. Additional Requirements for Expanding Excursion Plumes

i. For monitoring wells impacted by expanding excursion plumes, in addition to the monitoring required under Sections C.4.b and C.4.c of this Part above, the Permittee shall collect a groundwater sample from the impacted well(s) and analyze the sample(s) for the water quality parameters in Table 8.

ii. The Permittee must continue to analyze groundwater samples from impacted monitoring wells described under Section C.g.i above for the water quality parameters in Table 8 on a monthly basis until **excursion parameter concentrations** show decreasing concentrations for three consecutive weekly sampling periods required under Section C.4.c of this Part above. Table 8 water quality parameter analytical results must be used to calibrate the geochemical model required under Section C.5 of this Part below.

iii. After the excursion is corrected, the Permittee must collect a final sample from each impacted non-injection interval monitoring well and analyze it for the water quality parameters in Table 8 to determine if additional aquifer remediation is required in the excursion-impacted area.

5. Geochemical Modeling for Expanding Excursion Plumes

a. If monitoring under Section C.4.f of this Part shows that concentrations of ISR contaminants included in Appendix B, Table B-1 are detected above background in a monitoring well impacted by an expanding excursion plume, the Permittee must notify the Director within 24 hours as required by Section E.9.d.i of this Part.

b. The background concentration for an ISR contaminant is the Commission-approved background concentration for that monitoring well determined according to NRC License condition 11.3.

c. The Permittee must conduct the following verification steps to determine if ISR contaminant concentrations exceed background concentrations:

i. If one ISR contaminant exceeds its background concentration by 20% or two or more ISR contaminants exceed background concentrations by 10%, within 48 hours the Permittee must collect a follow-up confirmation groundwater sample from the monitoring well and analyze it for the ISR contaminants with concentrations above background.

ii. If the second sample confirms elevated concentrations of ISR contaminants meeting criteria in Section C.5.***c.i*** above, then the Permittee must initiate the activities under Section C.5.***d*** below. If not, within 48 hours the Permittee must collect a third groundwater sample from the monitoring well and analyze it for the ISR contaminants with concentrations above background.

iii. If the third sample does not show ISR contaminant concentrations above background, then the Permittee does not need to initiate the activities under Section C.5.***d*** below.

d. Upon verification that ISR contaminants have increased in concentrations above background concentrations, the Permittee must conduct the following activities:

i. As required by Section E.9.d.ii of this Part, the Permittee must notify the Director within 24 hours of receiving the verification sampling results and follow-up in 5 days with a brief written report providing a schedule for the following activities.
ii. The Conceptual Site Model must be updated with all available information list in Part IV, Section A.1 for the non-injection interval aquifer impacted by the expanding plume.
iii. The Permittee must initiate the geochemical modeling process.

e. The geochemical model must:
i. Be calibrated to flow and geochemical conditions present at the excursion site and excursion parameter concentrations measured in the monitoring well(s);
ii. Evaluate the extent of the excursion plume;
iii. Determine the potential for the excursion plume to reach the aquifer exemption boundary at the current rate of expansion; and
iv. Estimate the concentrations of ISR contaminants at the aquifer exemption boundary, taking into account the effects of dispersion and natural attenuation based on the geochemistry of the aquifer unit.

f. After reviewing the model results, the Director will determine what actions the Permittee should take to protect USDWs, including the installation of additional monitoring wells and aquifer remediation, if needed.

6. Requirement to Remediate Excursions

The Permittee must take appropriate action to recover an excursion and continue excursion monitoring at all impacted monitoring wells until the excursion parameter concentrations meet non-excursion levels for four consecutive monitoring periods in all impacted monitoring wells. Non-excursion levels means no single excursion parameter exceeds 20% of its UCL and no two excursion parameters exceed their respective UCLs in any monitoring well.

D. Seismic Activity Monitoring

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service known as the Earthquake Notification Service (ENS), which reports real-time earthquake events for any area specified by the user. Details for the ENS can be found at: https://earthquake.usgs.gov/ens/

1. The Permittee must subscribe to this service and check daily for notification emails from the service.
2. The Permittee must notify the Director within twenty-four (24) hours of any seismic event measuring 4.5 magnitude (MMI scale) or greater reported within two miles of the permit boundary.
3. If any seismic event of magnitude 4.5 (MMI scale) or greater is reported within two miles of the permit boundary, the Permittee must immediately cease injection.
4. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes.
5. Injection must not resume until the Permittee has obtained approval to recommence injection from EPA.
6. The Permittee must record any seismic event measuring 2.0 magnitude (MMI scale) or greater occurring within fifty miles of the permit boundary and report such events to EPA on a quarterly basis.

E. Reporting Requirements

Monitoring may be reported on a project or field basis rather than individual well basis where manifold monitoring is used.

1. Reporting requirements must, at a minimum, include:

a. Quarterly reporting to the Director on required monitoring required by this Permit;
b. Results of mechanical integrity demonstrations as required under Sections 6 and 7 below and any other periodic test required by the Director.
c. Updates to the Conceptual Site Model required under Part IV, Section A.3.

2. Following authorization to begin injection into a wellfield, the Permittee must submit Quarterly Monitoring Reports to the Director containing the monitoring information required in Section B of this Part whether the wellfield is operating or not.
   a. Reporting periods and due dates for Quarterly Monitoring Reports are shown in Section E.8.b, Table 17 of this Part.
   b. An electronic format may be used to submit monitoring information using the data fields included on EPA Form 7520-8 *Injection Well Monitoring Report* found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm as a guide.
   c. However, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-8 indicates otherwise.

3. Injection Authorization Data Package Reports

Injection Authorization Data Package Reports must be prepared and submitted to the Director for each wellfield in order to obtain written Authorization to Commence Injection in that wellfield. These data packages may be submitted when completed and do not have to be submitted on the Quarterly Monitoring Report schedule shown below. The Injection Authorization Data Package Reports must be signed according to Part XII, Section D.9 and certified using the paragraph included under Part XII, Section D.9.d. The information may be submitted in a standardly available electronic format but must be accompanied by a letter containing the required certification.

4. Injection, Production and Monitoring Well Completion Reports

a. After an injection, production or monitoring well has been completed, the Permittee must submit a well completion report including the information in EPA Form 7520-9 *Completion Form for Injection Wells* with attachments.
b. The report may be in electronic format including the completion information for a number of wells. The EPA Form 7520-9 can be found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm.
c. The well construction report must also contain the manufacturer-specified maximum operating pressure for all components of the injection or production well.
d. The cementing procedure must be documented in detail in each well completion report.
e. Remedial cementing may be required if the Director determines the well cementing record is not adequate for demonstration of external mechanical integrity.
f. Injection well completion reports must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless well construction was completed within 45 days of the next Quarterly Monitoring Report due date.

g. If well construction was completed within 45 days of the next Quarterly Monitoring Report due date, the well completion report must be submitted with the following Quarterly Monitoring Report.

5. Demonstration that Manifold Monitoring of Injection Pressure is Comparable to Wellhead Monitoring

a. Demonstration must consist of a list of injection pressures measured at each wellfield injection wellhead compared to the injection pressure measured at the pressure gauge at each header house and the time and date each injection pressure measurement was collected.
b. The Permittee must conduct a bounding analysis demonstration for each header house that manifold monitoring is comparable to individual well monitoring using the maximum anticipated carbon dioxide and oxygen injection rates.
c. The Permittee must make an effort to record the measurements at the same time from wellhead pressure gauge and the header house pressure gauge.
d. The report must consist of
    i. injection well identification numbers,
    ii. injection pressure measured at each wellhead,
    iii. time and date of measurement,
    iv. header house identification number for the injection well,
    v. header house injection pressure measured,
    vi. time and date of measurement,
    vii. maximum anticipated flow rate of carbon dioxide for the header house and
    viii. maximum anticipated flow rate of oxygen for each injection well.
e. This information must be included in the next Quarterly Report after the information is compiled.
f. After the initial demonstration for a wellfield, if adjustments are made to the oxygen flow rate or carbon dioxide flow rates outside the range of the bounding analysis, then a new demonstration is required.

6. Initial Internal Mechanical Integrity Reports

The initial mechanical integrity test results required under Part VII, Sections B.2 and B.3 must be submitted to the Director in order to obtain written Authorization to Commence Injection. The mechanical integrity test results may be submitted when completed and do not have to be submitted on the Quarterly Monitoring Report schedule shown below. The mechanical integrity test results must be signed according to Part XII, Section D.9 and certified using the paragraph included under Part XII, Section D.9.d. The information may be submitted in electronic format but must be accompanied by a letter containing the required certification.

7. Ongoing Demonstrations of Mechanical Integrity

The results from ongoing mechanical integrity tests must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless the mechanical integrity test was completed within 45 days of the next Quarterly Monitoring Report due date. In that case, the information must be submitted with the following Quarterly Monitoring Report.

8. Quarterly Monitoring Reports

a. The Permittee must include the monitoring parameters listed under Section B of this Part in the Quarterly Monitoring Report as specified here.

b. The Permittee must submit the Quarterly Monitoring Reports to Director according to the schedule included in Table 17.
c. At minimum, the Permittee must include in the Quarterly Monitoring Reports the following information:
    i. Monthly physical, chemical and other relevant analytical results of injection fluids.
    ii. Monthly average, maximum and minimum values for injection pressure, flow rate and volume.
    iii. Quarterly mechanical integrity test results, a list of any wells failing mechanical integrity test and remedial actions taken, and a list of wells anticipated to undergo mechanical integrity testing during the next quarter.
    iv. Operational monitoring results.
    v. Excursion monitoring results.
    vi. Post-restoration wellfield post-restoration stability monitoring results.
    vii. Any seismic events measuring 2.0 magnitude (MMI scale) or greater within a 2-mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website.
    viii. Any well maintenance activities.
    ix. Updates to the Conceptual Site Model required under Part IV, Sections A.3 and A.4.

d. The Permittee must sign and certify the monitoring reports according to the Draft Area Permit Part XII, Sections D.9 and D.9.d.
e. The Permittee may submit quarterly Monitoring Reports in electronic format, but the electronic data must be accompanied by a letter containing the required certification.

U.S. Environmental Protection Agency – Region 8
Chief, SDW Enforcement Branch, Mailcode: 8ENF-W-SDW
Enforcement and Compliance Assurance Division
1595 Wynkoop Street
Denver, CO 80202-1129

f. The Permittee must include in the monitoring reports raw data and graphical analysis for the current reporting period to date.
g. The Permittee must tabulate each calendar quarter, the maximum, minimum, and average monthly values for each continuously monitored parameter specified for the injection wells.
h. The Permittee must include a narrative description of any deviations from permit limitations that occurred during the reporting period.
i. The Permittee must describe any maintenance activities, mechanical integrity test activities, and other significant events that took place during the reporting period.

Table 17. Schedule for Submitting Quarterly Monitoring Reports

QUARTER	REPORTING PERIOD	REPORT DUE TO EPA
1st Quarter	January 1 – March 31	May 15
2nd Quarter	April 1 – June 30	August 15
3rd Quarter	July 1 – September 30	November 15
4th Quarter	October 1- December 31	February 15

9. Excursion Reporting

a. Initial Excursion Reporting

If an excursion has been confirmed under Section C.3 of this Part, the Permittee must notify the Director within 24 hours per Part XI, Section C.4.a and, within 5 days, follow up with a written report that provides the following information:

i. Location of excursion,
ii. Monitoring wells impacted,
iii. Date of previous excursion monitoring activities in the area, and
iv. Actions to correct the excursion.

b. 60 Day Excursion Reporting

i. Within 60 days of the excursion confirmation, the Permittee must submit a written report describing the excursion event, recovery actions taken and the recovery action results.
ii. If monitoring wells are still on excursion status when the report is submitted, the report will also contain a schedule for submittal of future reports describing the excursion event, recovery actions taken, and results obtained.

c. Reporting an Expanding Excursion Plume

i. If an expanding excursion is verified as described in Section C.4.f of this Part, the Permittee must notify the Director of an expanding excursion plume within 24 hours per Part XI, Section C.4.a and follow up with a written report within 5 days.
ii. The written report must contain an estimation of how far excursion plume may have traveled, including a map showing estimated extent of the expanding excursion plume.

d. Reporting Increase in Concentration of ISR Contaminants in Impacted Monitoring Wells

i. The Permittee must notify the Director within 24 hours as required by Section C.5.a of this Part if monitoring under Section C.4.g of this Part shows that concentrations of ISR contaminants included in Appendix B, Table B-1 are detected above background in a monitoring well impacted by an expanding excursion plume.
ii. As required by Section C.5.d.i of this Part, the Permittee must notify the Director within 24 hours of receiving the verification sampling results and follow-up in 5 days with a brief written report providing a schedule for the following activities:
   A) The Conceptual Site Model must be updated with all available information list in Part IV, Section A.1 for the non-injection interval aquifer impacted by the expanding plume.
   B) The Permittee must initiate the geochemical modeling process.

PART X. RECORDKEEPING REQUIREMENTS

A. Records of Permit Application Data

The Permittee must keep records of all data used to complete permit applications and any supplemental information submitted under 40 CFR § 144.31 for a period of at least 3 years from the date the application is signed.

B. Records of Monitoring Data

The Permittee must retain records of all monitoring information, including the following:

1. Calibration and maintenance records and data from continuous monitoring instrumentation, copies of all reports required by this permit, for a period of at least 3 years from the date all wells have been plugged and abandoned.
2. Well completion reports.
3. The nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures specified under § 144.52(a)(6), or under part 146 subpart G as appropriate.
4. Mechanical integrity test results, description and results of any other tests required by EPA, and any well workovers completed.
5. System failures and follow-up actions.
6. The Permittee must also maintain an electronic database containing well completion and mechanical integrity test records for all injection wells and provide it for EPA use upon request.
7. Records of all monitoring activities must be retained and made available for inspection. The Permittee must notify the Director as to the location where the records of monitoring activities are maintained and notify the Director if this location changes.
8. At the end of the retention period, the owner or operator must deliver the records to the EPA Regional Administrator or obtain written approval from the Regional Administrator to discard the records.

C. Retention Schedule for Well Plugging and Abandonment Reports

1. The Plugging and Abandonment Reports required under Part XI, Section D must be retained for at least 3 years from the date of the submission unless the Director requests an extension.
2. At the conclusion of the retention period, the reports will be delivered to the Director upon request.

PART XI. PLUGGING AND ABANDONMENT

A. Notification of Well Abandonment, Conversion or Closure

1. Except for the plugging and abandonment of a well that cannot demonstrate mechanical integrity under Part VII and will be replaced by a newly constructed well meeting the requirements in Part V, the Permittee must notify the Director in writing at least forty-five (45) days prior to:
   a. plugging and abandoning an injection well;
   b. converting to a non-injection well, other than a wellfield production well; and
   c. closure of the project.
2. Notification must include demonstration that the NRC considers the wellfield groundwater to be restored before the Director will authorize the closure of wellfield injection and production wells.
3. In accordance with 40 CFR § 146.10(a)(4), the plugging and abandonment plan required in 40 CFR §§ 144.51(o) and 144.52(a)(6) must demonstrate adequate protection of USDWs per 40 CFR § 146.10(a)(4).
4. Before approving well closure, the Director may prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to ensure adequate protection of USDWs per 40 CFR § 146.10(a)(4).

B. Well Plugging Requirements

1. Prior to abandonment, each Class III injection well must be plugged with bentonite or cement grout in a manner which prevents the movement of fluids into or between USDWs.
2. Each well must be plugged in accordance with the approved plugging and abandonment plan and with 40 CFR § 146.10.

C. Approved Plugging and Abandonment Plan

1. Wells must be plugged with bentonite grout if the weight of the bentonite grout column is greater than the bottom hole pressure or must be plugged with cement grout placed from the bottom of the well or hole to within eight feet of the ground surface. Cement grout must be placed from eight feet below ground surface to within three feet of the ground surface. The top three feet may be filled with native material. If a pipe cannot be lowered inside the well casing to place grout from the bottom to the top, the well may be plugged by making a tight connection to the top of the casing and pumping a volume of cement grout, sufficient to fill the well, under pressure into the well. Bentonite grout must not be used if the well is being plugged by making a tight connection to the top of the casing and pumping the grout in under pressure. If it cannot be verified that a well's casing was grouted in accordance with this chapter, an effort must be made to plug the annulus between the casing and the borehole wall from the bottom of the annulus up to the ground surface with the same type of material or materials required for plugging inside the casing.
2. Records must be kept of each well cemented including at a minimum the following information:
   a. well ID, total depth, and location
   b. driller, company, or person doing the cementing work
   c. total volume of grout placed down hole
   d. viscosity and density of the grout
3. The Permittee must remove any surface casing or cut off surface casing below ground and set a cement surface plug on each well plugged and abandoned.
4. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

D. Plugging and Abandonment Report

1. Within 60 days after plugging a well or at the time of the next quarterly report (whichever is less) the owner or operator must submit a report to the Director. If the quarterly report is due less than 15 days before completion of plugging, then the report must be submitted within 60 days. In accordance with this requirement, a Plugging and Abandonment Report (EPA Form 7520-13) must be submitted to the Director.
2. The plugging report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:
   a. A statement that the well was plugged in accordance with the approved plugging and abandonment plan in Section C of this Part; or
   b. Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan specifying the differences.
3. Documentation must be provided to verify that the quantity of sealing material placed in the well is at least equal to the volume of the empty hole.

4. The Plugging and Abandonment Reports will be retained for at least 3 years from the date of the submission unless the Director requests an extension. If requested, at the conclusion of the retention period, the reports will be delivered to the Director.

PART XII. CONDITIONS APPLICABLE TO ALL UIC PERMITS

A. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance or Termination

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR § 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a non-injection well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice must adequately demonstrate that the financial responsibility requirements of 40 CFR § 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the Permittee changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee must give advance notice to the Director, and must obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers must meet all conditions as set forth in this permit. The Permittee must record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and must provide this and any other record of well workovers, logging, or test data to EPA with the next quarterly report. If the quarterly report is due within 30 of the activity, then the Permittee must include the information in the subsequent quarterly report.

B. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

C. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR part 2 (Public Information).

Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

D. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Need to Halt or Reduce Activity Not a Defense

It must not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

3. Duty to Mitigate

The Permittee must take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

4. Proper Operation and Maintenance

The Permittee must at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate Permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

5. Permit Actions

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

6. Property Rights

This Permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information

The Permittee must furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee must also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

8. Inspection and Entry

The Permittee must allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;
b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,
d. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Signatory Requirements

All reports or other information requested by the Director must be signed and certified as follows:

a. All reports required by this permit and other information requested by the Director must be signed as follows:
    i. for a corporation—by a responsible corporate officer, such as a president, secretary treasurer, or vice president of the corporation in charge of principal business function, or any other person who performs similar policy or decision-making functions for the corporation;
    ii. for partnership or sole proprietorship—by general partner or the proprietor, respectively; or
    iii. for municipality, state, federal, or other public agency—by either a principal executive or a ranking elected official.
b. A duly authorized representative of the official designated in paragraph (a) above also may sign only if:
    i. the authorization is made in writing by a person described in paragraph (a) above;
    ii. the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a wellfield, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and
    iii. the written authorization is submitted to the Director.
c. If an authorization under paragraph (b) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (b) of this section must be submitted to the Director prior to

or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph (b) of this section must make the following certification:

> *I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment.*

10. Reporting Requirements

Before written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Part XII, Sections D.9 and D.9.b of this permit and must be submitted to the EPA at the following address:

U.S. Environmental Protection Agency – Region 8
Chief, Underground Injection Control Section, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129

After written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under D.9 and D.9.b of this Part and must be submitted to the EPA at the following address:

U.S. Environmental Protection Agency – Region 8
Chief, Water Enforcement Branch, Mailcode: 8ENF-W-SD
Enforcement and Compliance Assurance Division
1595 Wynkoop Street
Denver, CO 80202-1129

All correspondence must reference the well name or wellfield name and location and include the EPA Permit number.

a. Planned changes. The Permittee must give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.
b. Anticipated noncompliance. The Permittee must give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
c. Monitoring Reports. Monitoring results must be reported at the intervals specified in this Permit.
d. Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit must be submitted no later than 30 days following each schedule date.
e. Twenty-four hour reporting. The Permittee must report to the Director any noncompliance which may

endanger human health or the environment, including:

i. Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

ii. Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

In addition, a follow up written report must be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission must contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

f. Information must be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region 8 Emergency Operations Center at (303) 293-1788.

g. The written report must also be provided to the Director in electronic format for release to the public and tribal governments on the EPA Region 8 UIC website.

h. Oil Spill and Chemical Release Reporting: The Permittee must comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center at **(800) 424-8802.**

i. Other Noncompliance. The Permittee must report all instances of noncompliance not reported under paragraphs Section D.10.b, Section D.10.e or Section D.10.h of this Part at the time the monitoring reports are submitted. The reports must contain the information listed in Section D.10.g of this Part and be provided to the Director in electronic format as required in Part XII, Section D.10.h.

j. Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee must promptly submit such facts or information to the Director.

PART XIII. FINANCIAL RESPONSIBILITY

A. Method of Providing Financial Responsibility

The permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§ 144.51(o), 146.10, and 146.92 of this chapter, and submitted a plugging and abandonment report pursuant to 40 CFR § 144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR § 144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility must become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is

acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

1. Types of Adequate Financial Responsibility

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

a. a surety bond with a standby trust agreement,
b. a letter of credit with a standby trust agreement,
c. a fully funded trust agreement, OR
d. an independently audited financial statement with a Chief Financial Officer's letter.

A surety bond acceptable to the Director must contain wording identical to EPA's model language and must be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70) and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

A fully funded trust agreement acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70). Annual reports from the financial institution managing the trust account must be submitted to the Director showing the available account balance.

An independently audited financial statement with a Chief Financial Officer's letter acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70) and must demonstrate the Permittee meets or exceeds certain financial ratios. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year.

A standby trust agreement acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70). Annual reports from the financial institution managing the standby trust account must be submitted to the Director showing the available account balance.

2. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, must submit 3 current independent plugging and abandonment cost estimates for the Director to accurately determine the likely cost to plug the well(s).

B. Insolvency

In the event of:

1. the bankruptcy of the trustee or issuing institution of the financial mechanism; or
2. suspension or revocation of the authority of the trustee institution to act as trustee; or
3. the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after

any event specified in 1, 2, or 3 above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or Permittee as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

C. Timing for Updated Cost Estimate and Demonstration of Financial Responsibility

1. The Permittee must provide annual updates by providing the Director with a list of wells planned for construction in the upcoming year and the demonstration of adequate Financial Responsibility for the new wells.
2. This information must be provided to the Director by December 1 every year, to provide time for the Director to review and approve the updated demonstration of Financial Responsibility by Jan 1 of the following year.

D. This surety fulfills a portion of the decommissioning activities cited in the U.S. Nuclear Regulatory Commission Materials License SUA-1600, pursuant to Title 10 Code of Federal Regulations Part 40, Appendix A, Criterion 9.

PART XIV. COMPLIANCE WITH APPLICABLE FEDERAL LAWS

UIC regulation 40 CFR § 144.4, Considerations under Federal law, specifies federal laws that the EPA must comply in issuing UIC permits. When any of these laws is applicable, its procedures must be followed. When the applicable law requires consideration or adoption of particular permit conditions or requires the denial of a permit, those requirements also must be followed.

A. The National Historic Preservation Act (NHPA) of 1966, 16 U.S.C. 470 et seq.

Section 106 of the NHPA and implementing regulations at 36 CFR part 800 require federal agencies to take into account the effects of their undertakings on historic properties.

In accordance with section 106 and the regulations at 36 CFR part 800, the Permittee must comply with the following measures:

1. The Permittee must abide by the Programmatic Agreement among U.S. Nuclear Regulatory Commission, U.S. Bureau of Land Management, South Dakota State Historic Preservation Office, Powertech (USA), Inc., and the Advisory Council on Historic Preservation Regarding the Dewey-Burdock In-Situ Recovery Project Located in Custer and Fall River Counties South Dakota (PA) (March 19, 2014).

2. When evaluated properties are eligible for the National Register of Historic Places, avoidance of the properties will be the preferred option. When avoidance is not possible and adverse effects will result, adverse effects will be resolved in accordance with Stipulation 5 of the PA: Resolution of Adverse Effects.

3. The Permittee will ensure that its employees and contractors involved in the Project are aware of and comply with the requirements of the PA. The Permittee may use measures such as initial orientation training and pre-job briefings to inform employees and contractors of their responsibilities under the PA in accordance with Stipulation 13a of the PA.

4. If a previously unknown cultural resource is discovered during the implementation of the Project, all ground-disturbing activities within 150 feet of the area of discovery must halt so as to avoid or

minimize impacts until the property is evaluated for listing on the NRHP by qualified personnel. The Permittee must ensure the steps listed under Stipulation 9 of the PA are followed.

B. The Endangered Species Act (ESA), 16 U.S.C. 1531 et seq.

Section 7(a)(2) of the ESA and its implementing regulations (50 CFR part 402) require the EPA to ensure, in consultation with the Secretary of the Interior or Commerce, that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of the designated critical habitat of such species.

1. EPA incorporates the following measures in the UIC permits to avoid, minimize or mitigate any potential impacts to federally-listed species:

a. In the event that construction is planned during the whooping crane and rufa red knot migration seasons or the northern long-eared bat (NLEB) active season, within five days prior to the initiation of any construction activities, a qualified biologist must conduct pre-construction surveys for these species and training for workers to assist with the identification of all listed species during construction and operation.
   i. Whooping crane migration seasons: migrates through South Dakota April 1 to mid-May and mid-September to mid-November.
   ii. Rufa red knot migration seasons: migrates through South Dakota mid-April to mid-May and mid-September to October 31.
   iii. NLEB active season: mid-April to October 31. The critical pup season is June 1 – July 31.

b. If the whooping crane, the rufa red knot or the northern long-eared bat are sighted within one-half mile of the well sites or associated facilities during construction or operation, the Permittee must contact EPA and the FWS immediately and all construction work within one-half mile of the species' location must cease. Powertech will work with the FWS and a qualified biologist to minimize surface operation activities within one-half mile of the species' location. In coordination with the FWS, work may resume after the species leave the area. For this measure and other ESA-related matters related to this project, the Permittee should contact the FWS and EPA by phone, followed up by an e-mail. The contact points are:
   - The FWS South Dakota Field Office – (605) 224-8693, email: southdakotafieldoffice@fws.gov
   - EPA Region 8 UIC Program – (303) 312-6079, email: minter.douglas@epa.gov

c. Any wells, equipment or buildings associated with the UIC wells authorized under the permit with a fixed location within the project area must be constructed to eliminate openings that look like a small cave or hibernacle to avoid the entrance of any northern long-eared bats.

d. Spills or leaks of chemicals and other pollutants at the UIC well site must be reported to the appropriate regulatory agencies. The procedures of the surface management agency must be followed to contain leaks or spills.

e. If supplemental lighting is used during construction or operation activities, as a protection measure for northern long-eared bat, the lights must be directed and/or sheltered to minimize the amount of light escaping the work or project site.

f. The Permittee must install netting, use bird balls or other acceptable bird deterrent method to prevent birds and bats from accessing all project ponds.

g. Tree removal activities within the project area must be conducted outside of the northern long-eared bat active season (mid-April to October 31). This will minimize impacts to the northern long-eared bat, including to NLEB pups during the critical pup season.

h. During the northern long-eared bat active season (mid-April to October 31), the Permittee must use a motion-activated camera to monitor the Triangle Mine vertical ventilation shaft located at NWNW Section 35, T6S, R1E for 5 days and nights and determine if bats are entering and exiting. If no bats are observed entering or exiting the shaft, the Permittee must investigate the shaft to determine if bats are inside the shaft. If no bats are inside the shaft, the Permittee must cover the entrance to the shaft with finer mesh to prevent bats from entering. If bats are observed in the shaft, the Permittee must work with South Dakota Game, Fish and Parks to evaluate methods for establishing an appropriate buffer zone around the shaft to prevent tree removal or wellfield construction activity. The buffer zone will need to take into account the fact that the shaft is only a few feet away from a road that is used by local residents and may be improved to use as an access road to the Project Site.

2. Record Keeping and Retention Requirements for Endangered Species Act Mitigation

The Permittee must document all activities related to compliance with Part XIV, Section B of this Permit. All records of such documentation must be retained and made available for inspection or upon request by the Director. The Permittee must notify the Director as to the location where the records of ESA mitigation activities are maintained and notify the Director if this location changes. All records must be retained until all wells have been plugged and abandoned after which the owner or operator must deliver the records to the Director or obtain written approval from the Director to discard the records

APPENDIX A
WELLFIELD CROSS SECTIONS

Figure A1. Cross Sections through Dewey Wellfields 1, 2 and 3

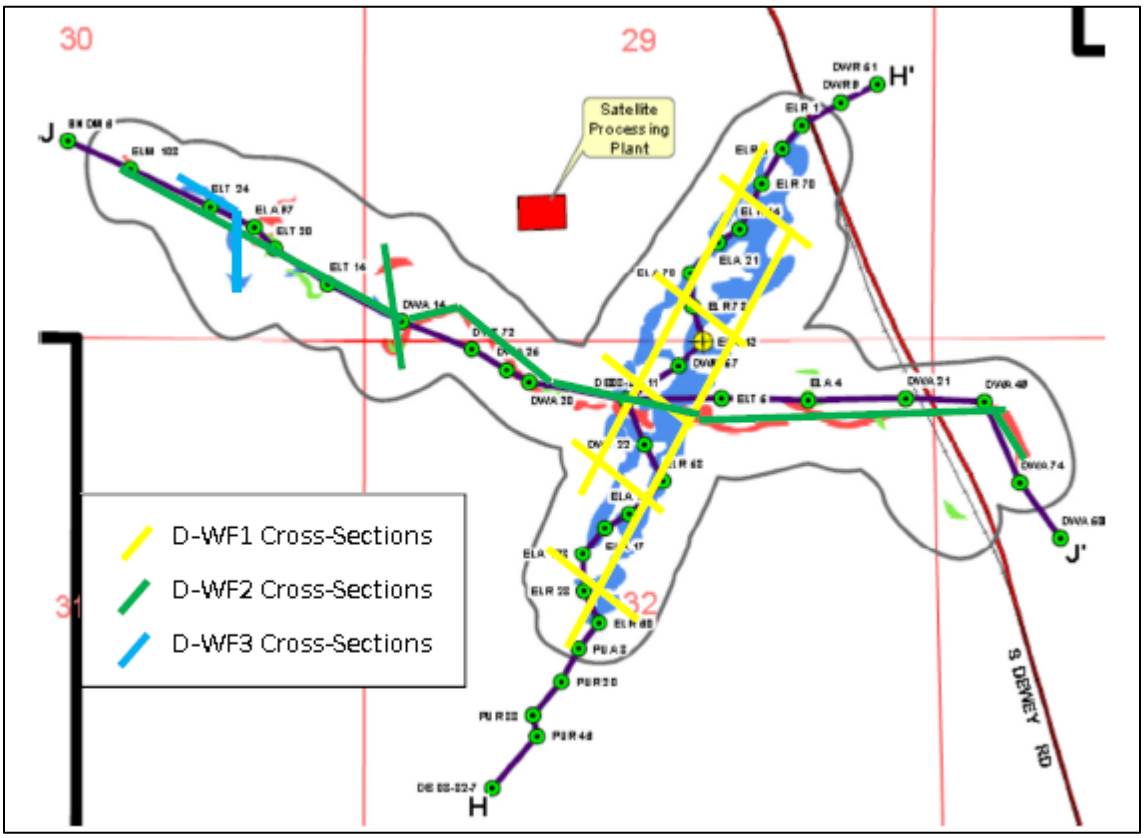


Figure A2. Cross Sections through Dewey Wellfield 4

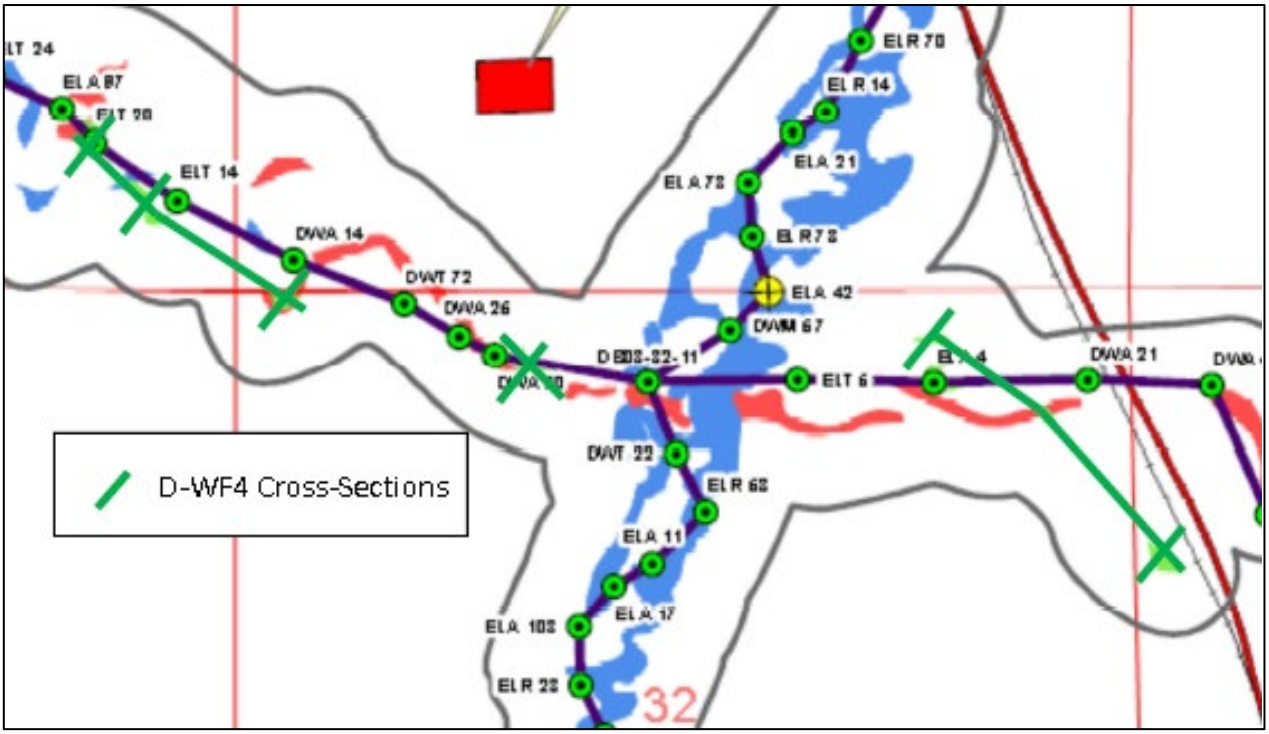


Figure A3. Cross Sections through Burdock Wellfield 4

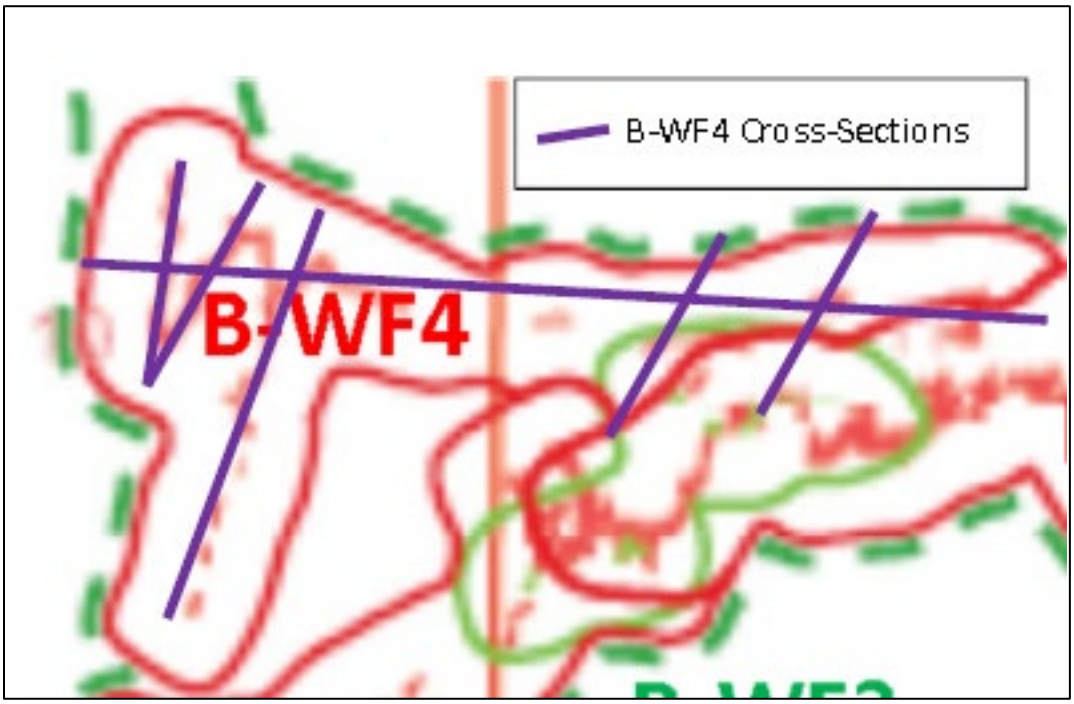


Figure A4. Cross Sections through Burdock Wellfields 5 and 9

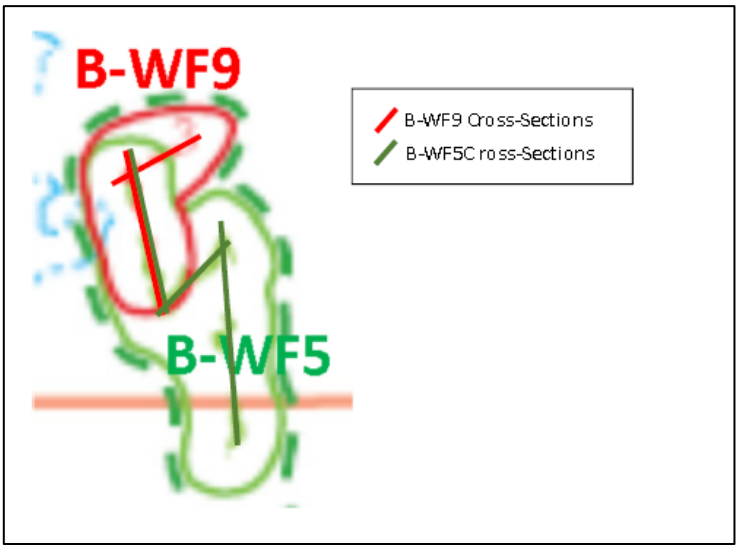


Figure A5. Cross Sections through Burdock Wellfields 6 and 7

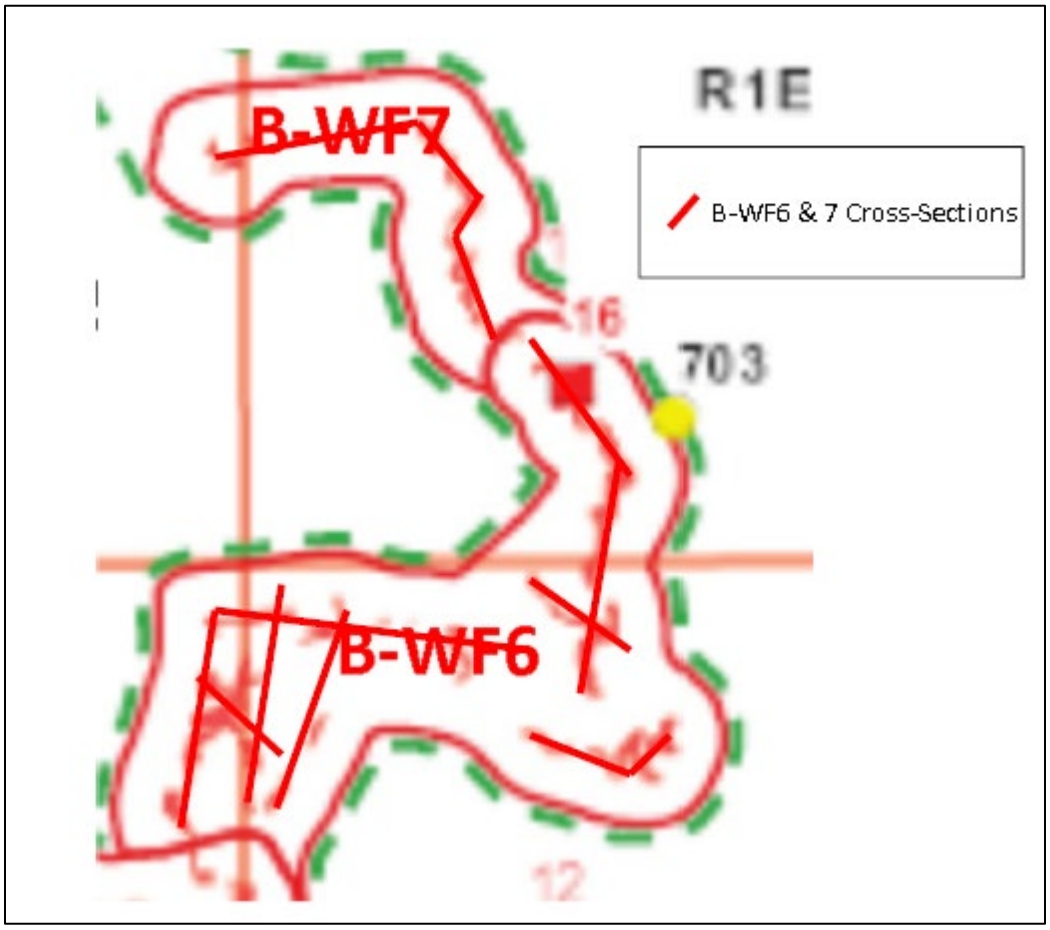


Figure A6. Cross Sections through Burdock Wellfield 8

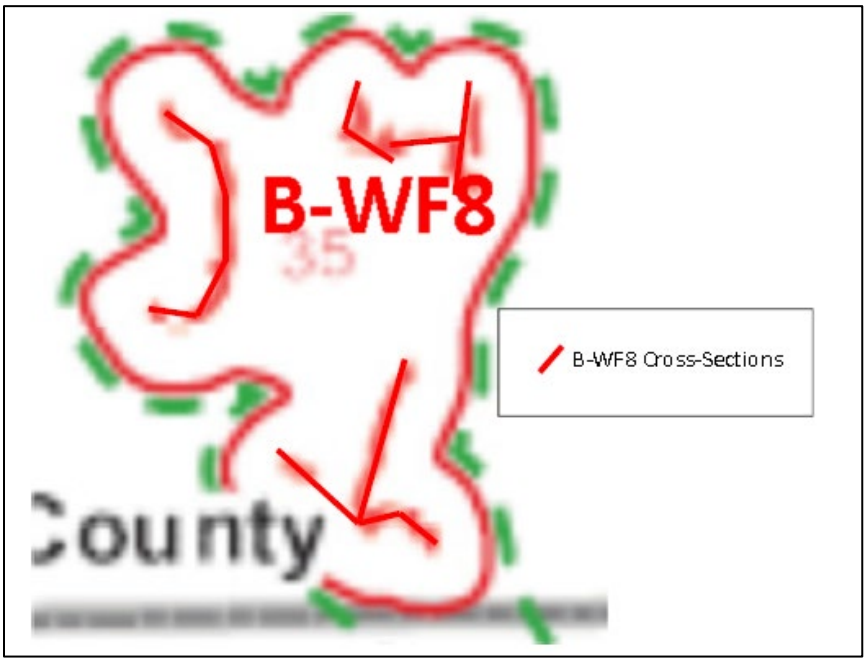
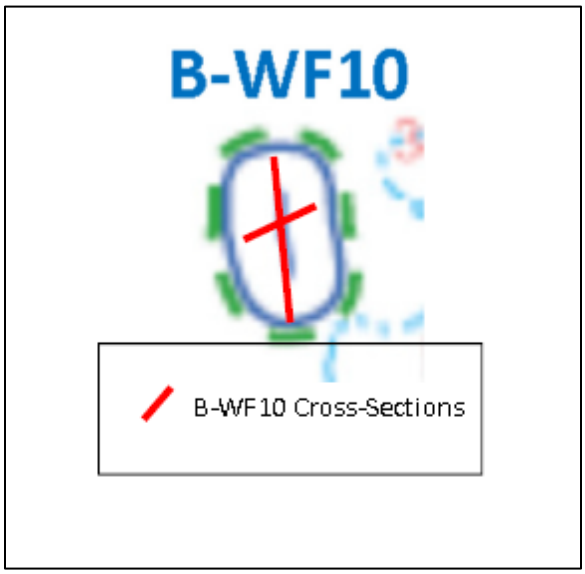


Figure A7. Cross Sections through Burdock Wellfield 10



APPENDIX B
ISR CONTAMINANT PERMIT LIMITS AT AE BOUNDARY

Table B-1. List of ISR Contaminants, Permit Limits, Standards Type and Required Analytical Method Minimum Detection Limit

Test Analyte/Parameter*	Permit Limit (mg/L)	Standard Type	Required Analytical Method Minimum Detection Limit (mg/L)
Antimony, Sb	0.006	MCL[1]	0.003
Arsenic, As	0.01	MCL	0.005
Barium, Ba	2	MCL	1
Beryllium, Be	0.004	MCL	0.002
Boron, B	6	HA-L[2]	3
Cadmium, Cd	0.005	MCL	0.0025
Chromium, Cr	0.1	MCL	0.05
Copper, Cu	1.3	LCR-Action Level[3]	0.65
Fluoride, F	4	MCL	2
Iron, Fe	5	R8-HBS[4]	2.5
Lead, Pb	0.015	LCR-Action Level[3]	0.0075
Manganese, Mn	0.3	HA-L	0.15
Mercury, Hg	0.002	MCL	0.001
Molybdenum, Mo	0.04	HA-L	0.02
Nickel, Ni	0.1	HA-L	0.05
Nitrate, NO_3^- (as Nitrogen)	10	MCL	5
pH	6.5-8.5 (pH units)	SMCL[5]	0.5 pH units resolution
Radium-226 + Radium-228	5 pCi/L (converted to mg/L)	MCL	2.5 pCi/L (converted to mg/L)
Selenium, Se	0.05	MCL	0.025
Silver, Ag	0.1	HA-L	0.05
Sodium, Na	20	HBS[6]	10
Strontium, Sr	4	HA-L	2
Sulfate, SO_4	500	HBS[7]	250
TDS	500	SMCL[5]	250
Thallium, Tl	0.002	MCL	0.001
Uranium, U	0.03	MCL	0.015
Vanadium, V	0.3	ATSDR MRL[8]	0.15
Zinc, Zn	2	HA-L	1

[1]MCL – Maximum Contaminant Level or Primary Drinking Water Standard
[2]HA-L – Health Advisory – Lifetime
[3]LCR-Action Level – Lead and Copper Rule action level
[4]R8-HBS – EPA Region 8 Health-Based Standard

[5]Secondary MCL
[6]EPA, 2003, Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on Sodium, EPA 822-R-03-006, 29 p.
[7]EPA, 2003, Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on Sulfate, EPA 822-R-03-007, 29 p.
[8]Based on Agency for Toxic Substances and Disease Registry oral intermediate Minimum Risk Level of 0.01 mg/kg-day using 80 kg and 2.4 L/day

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, COLORADO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

UNDERGROUND INJECTION CONTROL
FINAL
CLASS V AREA PERMIT

Date: September 2025

Area Permit No. SD52173-00000

Class V Deep Injection Well Area Permit
Dewey-Burdock Uranium In-Situ Recovery Project
Custer and Fall River Counties, South Dakota

Issued To

Powertech (USA) Inc.
P.O. Box 448
Edgemont, SD 57735

PART I. EFFECT OF PERMIT

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147,

Powertech (USA) Inc.
P.O. Box 448
Edgemont, SD 57735

hereinafter referred to as the "Permittee," is authorized to construct and operate wells in accordance with the conditions of this Area Permit.

Because this permit authorizes more than one injection well, it is an Area Permit and subject to the requirements found at 40 CFR § 144.33. The Permittee is allowed to engage in underground injection in accordance with the conditions of this Area Permit. The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable State or local laws or regulations.

This Area Permit authorizes the construction and operation of up to four (4) Class V disposal wells injecting only into the Minnelusa Formation within the Permit Area described below according to the conditions set forth in the Area Permit. The construction of more than four (4) injection wells injecting into the Minnelusa Formation injection zone is a violation of this permit. The Permittee may request to construct more than four (4) injection wells through a major modification to this permit according to 40 CFR § 144.39 and § 124.5, which would invoke the public review process required under 40 CFR part 124.

A. Class V Permit Area Boundary

Figure 1 shows the Dewey-Burdock Project Boundary (shown as a thick red line) and the Class V Permit Area in Custer and Fall River Counties, South Dakota.

B. Well Location

Approximate location information for the proposed DW No. 1 Class V injection well is shown in Table 1. The anticipated depths of the injection zone are based on well logs provided in the Class V Permit Application. Actual injection zone depths will be determined by well logs performed on each injection well as described in Part II, Section C.

Table 1. DW No. 1 Injection Well Proposed under the Class V Area Permit

Well Permit Number	Well Name	Approximate Latitude	Approximate Longitude	Proposed Injection Zone	Anticipated Injection Zone Depth (ft below ground surface)	Location within Permit Area
SD52173-08764	DW No. 1	43.469772181	-103.971938654	Minnelusa Formation	~1,615 - 2,355'	Burdock Area

Permit requirements herein are based on regulations found in 40 CFR parts 2, 124, 144, 146, and 147, which are in effect on the Effective Date of this Permit. The UIC regulations specific to South Dakota are found at 40 CFR § 147, Subpart QQ.

This Area Permit is based on representations made by the applicant and on other information contained in the Administrative Record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Area Permit and/or formal enforcement action.

This Area Permit is issued for a period of ten (10) years unless modified, revoked and reissued, or terminated under 40 CFR § 144.39, § 144.40, or § 144.41. This Permit may be adopted, modified, revoked and reissued, or terminated if the primary enforcement authority for this program is delegated to the State of South Dakota. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions must be directed to the State Program Director or designee.

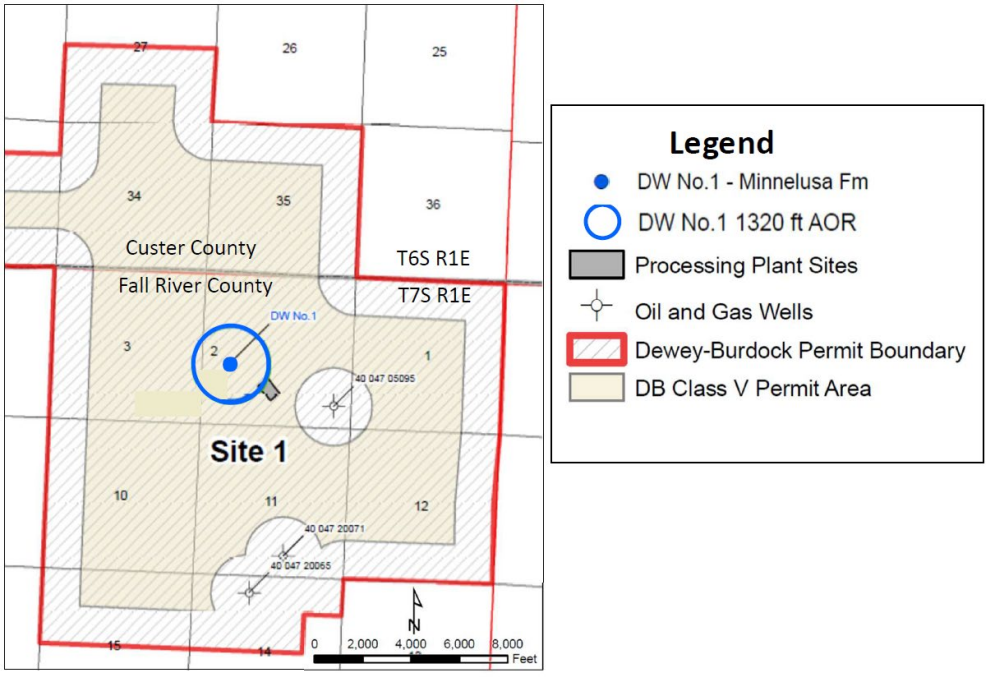
Effective Date: 30 days after signature date

_____

Sarah Bahrman, Acting Director*
Water Division

*NOTE: Throughout this Permit the term "Director" refers to either the Director of the Water Division (or authorized representative) or the Chief of the Water Enforcement Branch of the Enforcement and Compliance Assurance Division (or authorized representative).

Figure 1. Dewey-Burdock Class V Area Permit Boundary



PART II. REQUIREMENTS FOR AUTHORIZATION TO INJECT

In order to obtain Authorization to Inject for any injection well under this Permit, the information required under this Part must be provided to the Director for evaluation in an Injection Authorization Data Package Report which must include a descriptive narrative interpreting the results of logs and tests prepared by a knowledgeable log analyst. The report must include a description of the methods used during logging or testing. The Permittee must ensure the log and test requirements are performed within the time frames specified.

A. Information to Submit to the Director to Obtain an Authorization to Inject

For each injection well, the Permittee must provide the following information, further described in Sections B through I, to the Director for evaluation. After evaluating the information, the Director will determine if it is appropriate to issue a written Authorization to Inject.

1. Well logging information, formation testing data and laboratory data from drill hole cores demonstrating that the injection zone is separated from underground sources of drinking water (USDWs) by an overlying confining zone identified in well logs which is demonstrated to have low permeability and low hydraulic conductivity. The Permittee must include annotations on logs, where appropriate, to identify aquifers, injection zones and confining zones.
2. Evaluation of the Minnelusa aquifer injection zone fluids to confirm the injection zone formations are hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
3. Evaluation of the Madison aquifer fluids at the Madison water supply wells (if constructed), to provide additional confirmation that the injection zone is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
4. The Total Dissolved Solids (TDS) concentration of each perforated zone will be determined by two swab

samples. If any swabbed zone contains less than 10,000 mg/L TDS, the injection zone is a USDW. The Director will not authorize injection into an USDW under this Area Permit.

5. Calculations of critical pressures and injection-induced injection zone pressures for the injection zone based on site-specific information and 10 years of injection activity. This information must be used to demonstrate that each injection well is located at a sufficient distance from any feature so that there is not sufficient pressure to move fluids into USDWs.
6. Well construction completion report using EPA Form 7520-9 containing information demonstrating that the injection zone is isolated from USDWs by well casing and cement.
7. Location of well perforations within the approved injection zone.
8. Demonstration of internal and external mechanical integrity for each injection well.
9. Results of step rate testing to determine the site-specific maximum allowable injection pressure (MAIP) for each well.
10. Results of a temperature survey or radioactive tracer survey for each injection well to establish a baseline assessment of Part II Mechanical Integrity and provide injectivity profile information.
11. The testing procedures, results and interpretation of results for the formation testing required under Part II, Section D must be included in the Injection Authorization Data Package Report.

B. Collection of Drill Core in the Injection Zone and Confining Zones

1. The Permittee must collect drill core from the injection zone, the overlying confining zone formation and the underlying confining zone as described in Table 2 for the reasons stated in Table 2. Laboratory data may be supplemented by data from pressure transient testing and porosity information from the Borehole Compensated (BHC) Sonic log.
2. The Permittee must compare geologic logs from the first well with subsequent wells to demonstrate consistency and continuity of the geologic intervals.
3. The information must be included in the Injection Authorization Data Package Report for each Class V injection well.
4. The effective porosity and permeability, and the percentage of flow into each injection zone must be used as the input values in the equation used to calculate decline of injection zone pressure with distance away from the injection well described in Part II, Section F.2.

Table 2. Drill Core Collection for Laboratory Testing

CORE INTERVAL	PURPOSE	DUE DATE
While drilling each injection well, core samples must be collected in each Minnelusa injection zone.	For laboratory testing to determine the porosity, effective porosity and permeability of the injection zone	Prior to receiving Authorization to Inject
While drilling the first injection well, core samples must be collected within the Opeche Shale Confining Zone	For laboratory testing to determine the permeability and hydraulic conductivity of the overlying confining zone.	Prior to receiving Authorization to Inject
While drilling each Madison water supply well (if constructed), core samples must be collected from the Lower Minnelusa confining zone.	For laboratory testing to provide additional confirmation that the injection zone is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.	Within 30 days of core analysis

C. Well Logging Requirements

1. The Permittee must perform the logging operations listed in Tables 3, 4 and 5 on each injection well drill hole and casing.
2. Madison water supply wells (if constructed), the Permittee must conduct a minimum of mud logging, spontaneous potential logging, BHC sonic open-hole logging, and cement bond logs on the well surface and long string casing. Logs must be submitted to EPA within 30 days.
3. The reasons for conducting these well logs include:
   a. Defining the vertical extent of the injection zone and the overlying and underlying confining zones to confirm that the injection zone is separated from overlying and underlying USDWs by the confining zones;
   b. Verifying that there is adequate cement bond to prevent injected fluids from migrating outside of the authorized injection zone.

Table 3. Surface Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Dual Induction Laterolog	Open-hole formation evaluation	Prior to setting surface casing
Gamma Ray	Open-hole formation evaluation	Prior to setting surface casing
BHC Sonic	Open-hole formation evaluation	Prior to setting surface casing
Formation Density	Open-hole formation evaluation	Prior to setting surface casing
Caliper	Open-hole cement estimate	Prior to setting surface casing
Cement Bond Log[1]	Cement quality behind the surface casing	Prior to drilling out surface casing

[1] Recommendations for Cement Bond Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

Table 4. Long String Casing: Open Hole Logs

TYPE OF LOG	PURPOSE	DUE DATE
Mud Logging	Open-hole formation evaluation	During drilling
Dual Induction Laterolog	Open-hole formation evaluation	Prior to setting long string casing
Spontaneous Potential	Open-hole formation evaluation	Prior to setting long string casing
Gamma Ray	Open-hole formation evaluation	Prior to setting long string casing
BHC Sonic	Open-hole formation evaluation	Prior to setting long string casing
Formation Density	Open-hole formation evaluation	Prior to setting long string casing
Compensated Neutron	Open-hole formation evaluation	Prior to setting long string casing
Fracture Finder (Micro-resistivity)	Open-hole formation evaluation	Prior to setting long string casing
Caliper	Open-hole cement estimate	Prior to setting long string casing

Table 5. Long String Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Cement Bond Log[2]	Cement quality behind the long string casing	Prior to receiving Authorization to Inject
Casing Inspection Log	Long string casing quality	Prior to receiving Authorization to Inject

[2] Recommendations for Cement Bond Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

D. Formation Testing

1. Formation Tests to Conduct

For each aquifer listed in Table 6, the Permittee must conduct the formation tests listed in Table 7 for the purposes stated in Table 7.

Table 6. Aquifer to be Tested

Well Drill Hole	**Aquifers to be Tested**
DW No. 1	Each perforated zone in the Minnelusa Formation separated by a confining layer
Madison water supply wells (if constructed).	Stratigraphic intervals correlating to each perforated zone in the Minnelusa Formation separated by a confining layer at the injection wells, Madison aquifer

Table 7. Formation Testing Program

TYPE OF TEST	PURPOSE	DUE DATE
Open-hole fluid samples may be taken at the Permittee's discretion from each aquifer listed in Table 6 according to the requirements under Part II, Section D.2.	To allow Powertech to characterize the water quality from each aquifer specified in Table 6 prior to perforating and swab sampling.	Prior to receiving Authorization to Inject
Cased-hole swab samples must be taken from each Minnelusa perforated zone specified in Table 6 according to the requirements under Part II, Section D.2.	To demonstrate that each injection zone is not an USDW	Prior to receiving Authorization to Inject
Cased-hole potentiometric surface will be measured for each separate perforated zone	To determine potentiometric surface for each injection zone	Prior to receiving Authorization to Inject

Further characterization of each Minnelusa Injection zone with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.	To verify the Minnelusa injection zone and Madison aquifer are hydrologically separated as described in Part II, Section E.3.	Prior to receiving Authorization to Inject
Characterization of the Madison Formation water at the Madison water supply wells (if constructed), with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.	To verify the Minnelusa injection zone and Madison aquifer are hydrologically separated as described in Part II, Section E.3.	Within 30 days of acquisition of data
Madison water supply wells (if constructed). Measurement of additional parameters in the Madison aquifer required for updating the drawdown model of the Madison aquifer potentiometric surface described in Section 4.0 of the *Report to Accompany Madison Water Right Permit Application* submitted to the DENR Water Rights Program using site specific data.	To provide the input parameters for the drawdown model that will determine the expected drawdown in the Madison aquifer at each Madison water supply well with 10 years of pumping.	Within 30 days of acquisition of data.
Initial Temperature Survey Log[3]	To establish baseline temperatures of formations along well bore.	Prior to receiving Authorization to Inject

[3] Recommendations for Temperature Survey Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

2. Aquifer Fluid Sampling Requirements

a. The drilling program for each well must include the addition of a fluorescent dye tracer in the drilling fluids. The fluorescent dye tracer used for this purpose must be such that the Permittee is able to analyze for the presence of the tracer in aquifer fluid samples using field testing methods. The tracer must also be included as an analyte for laboratory testing of formation fluids to verify that no drilling fluid residual is present in the formation fluid samples. In the event that the dye dissipates in the drilling mud or formation fluid to the extent that it is not detectable during sampling, stabilized values of pH and conductivity during three successive casing volumes may be used to establish the presence of native formation fluids in accordance with Part II, Section 2.d.v.

b. Before aquifer sample collection, each aquifer must be isolated within the well or wellbore to prevent inflow of groundwater from other aquifers.

c. If open-hole samples are collected:

   i. For each isolated injection zone specified in Table 6, potentiometric surface elevations will be allowed to stabilize for 30 minutes. Fluid samples may then be collected.

   ii. A minimum of two fluid samples from each injection zone specified in Table 6 must be

collected. The second sample must be collected after one drill stem volume of groundwater has been removed after the collection of the first sample.

iii. The two fluid samples from each injection zone specified in Table 6 must be analyzed for TDS, Specific Gravity, pH, and Conductivity using the analytical methods shown in Table 8. Equivalent analytical methods may be used after prior approval by the Director. Analytical results must be reported in the units listed in Table 8.

iv. One drill stem volume of groundwater must be removed for the collection of each sample.[4]

d. Cased-hole Samples:

i. Potentiometric surface data must be determined for each perforated zone

ii. Swab sampling should take place prior to any formation stimulation or any other procedure where fluids may enter the formation and contaminate the naturally occurring formation water

iii. The sampling procedure should follow immediately after perforating a zone in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water.

iv. From each tubing volume recovered, measure the time, volume of fluid recovered, pH, and conductivity

v. When fluorescent dye is no longer detectable and pH and conductivity have stabilized (0.1 pH units and + 3% µmhos/cm, respectively) during three successive tubing volumes, collect two representative sample (one each, from two successive swab runs) for complete water analysis, measuring for each of the parameters and methods listed in Table 8.

vi. Except as may be required by the analytical method(s) shown in Table 8, samples must be analyzed for dissolved fractions.

vii. Equivalent analytical methods or total recoverable analysis may be used after prior approval by the Director.

e. The Permittee must include the following information in the Injection Authorization Data Package Report submitted to the Director:

i. Methods for aquifer isolation;

ii. Methods for sample collection;

iii. Methods for insuring fluid sample is representative of the aquifer conditions; and

iv. Methods for fluorescent dye tracer sampling, field testing and analysis.

[4] The EPA recommends that the Permittee consider capturing and storing aquifer fluids pumped to the surface in tanks to be used for aquifer testing involving injection.

Table 8. List of Analytes, Approved Analytical Methods and Reporting Units for Aquifer Fluid Testing

Analytes	Analytical Methods	Reporting Units
1. Total Alkalinity (as $CaCO_3$)	A2320B	mg/L
2. Arsenic	E200.8	mg/L
3. Barium	E200.8	mg/L
4. Bicarbonate Alkalinity (as $CaCO_3$)	A2320B (as HCO_3)	mg/L
5. Cadmium	E200.8	mg/L
6. Calcium	E200.7	mg/L
7. Carbonate Alkalinity (as $CaCO_3$)	A2320B	mg/L
8. Chloride	A4500-Cl B; E300.0	mg/L
9. Chromium	E200.8	mg/L
10. Specific Conductance	A2510B or E120.1	µmhos/cm at 25°C
11. Fluoride	E300.0	mg/L
12. Lead	E200.8	mg/L
13. Lead-210	E905.0 Mod.	pCi/L
14. Magnesium	E200.7	mg/L
15. Mercury	E200.8	mg/L
16. pH	A4500-H B	pH units
17. Potassium	E200.7	mg/L
18. Radium-226	E903.0	pCi/L
19. Radium-228	E904.0	pCi/L
20. Selenium	E200.8, A3114 B	mg/L
21. Silver	E200.8	mg/L
22. Sodium	E200.7	mg/L
23. Specific Gravity	ASTM D1429-13, SM 2710F	Ratio to density of water
24. Strontium	E200.8	mg/L
25. Sulfate	A4500-SO_4 E; E300.0	mg/L
26. Thorium -230	ASTM D3972-90	pCi/L
27. TDS	A2540C	mg/L
28. Drilling Fluid Tracer		
29. Uranium	E200.7, E200.8	mg/L
30. Uranium (Natural)	ASTM D3972-90	pCi/L

3. Demonstration that the Injection Zone Is Not an USDW

USDW means an aquifer or its portion:

a) 1) Which supplies any public water system; or

2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/L TDS.

b) Which is not an exempted aquifer

In order for the Director to issue Authorization to Inject, the Permittee must demonstrate the Minnelusa aquifer is not an USDW. This demonstration will be made by individual analysis of swab samples taken from each perforated zone immediately after perforating the zone. If the Permittee is able to demonstrate, based on analytical results from swab samples collected as required under Part II, Sections D.2, that the TDS of the injection zone fluids are 10,000 mg/l or greater, then the injection zone is not an USDW. If the TDS analyses of injection zone fluids are less than 10,000 mg/L, the injection zone is considered an USDW. This permit does not authorize injection into an USDW. If any Minnelusa injection zone is determined to be an USDW based on testing, the Permittee must obtain an aquifer exemption and a major a permit modification as described in Part IV, Section E in order to inject into the aquifer.

E. Evaluation of Confining Zones

The confining zones for the injection zone and approximate depths and thicknesses for each confining zone are shown in Table 9. The approximate depths and thicknesses are estimated from well logs included in the Class V permit application.

Table 9. Depths to Confining Zones for the Minnelusa Injection Zone in the Dewey and Burdock Areas

Injection Zone (Area)	Formation Name	Depth to Top (ft)	Depth to Base (ft)	Thickness (ft)
Minnelusa (Burdock)	Upper: Opeche Shale	1,520	1,615	95
	Lower: Lower Minnelusa Formation	2,355	2,765	410
Minnelusa (Dewey)	Upper: Opeche Shale	1,855	1,950	95
	Lower: Lower Minnelusa Formation	2,704	3,100	396

1. **Determination of Actual Depth and Thickness of Confining Zones**
   - **a.** The Opeche Shale is the upper confining zone immediately overlying the Minnelusa porosity injection zone. Logs from the DW No. 1 Class V injection well must be submitted to the Director for review of the Opeche Shale thickness at the location of each injection well. The Permittee must include annotations on the logs indicating the top and the base of the Opeche Shale.
     - i. The Permittee must also include annotations on the logs indicating the top of the Minnelusa Formation,
     - ii. The permittee must also include annotations on the logs indicating the top of the Red Marker within the Minnelusa porosity injection zone, and the expected depth of the shale markers indicating the top of the Lower Minnelusa confining zone shown in Table 9.
   - **b.** The Permittee must also provide logs of the Opeche Shale and the Minnelusa Formation from the Madison water supply wells (if constructed). The Permittee must include annotations on the logs indicating 1) the top and base of the Opeche Shale, 2) the top of the Minnelusa Formation, 3) the Red Marker within the Minnelusa, 4) the shale markers indicating the top of the Lower Minnelusa confining zone, and 5) the top of the Madison Formation.
2. **Core Sample Collection from Confining Zones**
   - **a.** During the drilling of the first injection well, core samples within the Opeche confining zone must be collected.

b. During the drilling of each Madison water supply well (if constructed), core samples must be collected within the Lower Minnelusa Formation lower confining zone.

c. The core samples must be analyzed in a laboratory to determine permeability and hydraulic conductivity of each confining zone.

3. Further Characterization of the Minnelusa Injection Zone Fluids and the Madison Aquifer

a. Evaluation of Anion/Cation Concentration and Potentiometric Surface Elevation Differences

i. The analytical results reporting units for samples from the Minnelusa injection zones and Madison aquifer samples (if Madison water supply wells are constructed) must be provided for the following anions and cations as both mg/L and milliequivalents/L as shown in Table 8. The milliequivalents/L concentrations must be determined individually and collectively as listed below:

A) Sodium + Potassium
B) Calcium
C) Magnesium
D) Chloride + Fluoride
E) Bicarbonate + Carbonate, and
F) Sulfate

ii. The milliequivalents/L results must also be plotted in the format of the Stiff Diagram shown in Figure 2.

iii. The Permittee must include in the Injection Authorization Data Package Report a written summary of the differences in formation fluid water quality and potentiometric surface elevation data of the Minnelusa injection zone and the Madison aquifer, including any data collected during the drilling, logging and testing of the Madison water supply wells (if constructed).

A) The Permittee must use this information to evaluate the effectiveness of the lower Minnelusa confining zone as described in Section 3.3.3 of the Class V Area Permit Fact Sheet.

B) The written statement must include characterization of the Minnelusa injection zone fluids, using the concentrations of the anions and cations listed above and reported in units of milliequivalents/liter, to verify that the concentration distribution matches the expected pattern found in areas where the Minnelusa injection zone and the Madison aquifer are hydrologically separated by a competent confining zone.

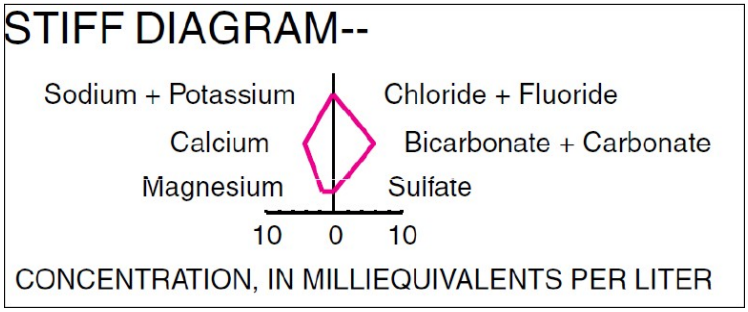


Figure 2. Format of Stiff Diagram for Anion and Cation Concentrations in the Minnelusa Injection Zone and the Madison Aquifer

b. Calculation of Potentiometric Surface Drawdown at the Madison Water Supply Wells (if constructed)

i. After the testing of the Madison aquifer has provided the information on the potentiometric surface and other parameters required, the Permittee must generate a drawdown model of the change in the potentiometric surface of the Madison aquifer that can be expected to result from 10 years of pumping the Madison aquifer at each of the Madison water supply wells.

ii. This information must be used for the calculations required under Part II, Section F.1.

F. Injection Zone Pressure and Maximum Injection Rate Calculations

1. Calculation of Critical Pressure Rise in the Minnelusa Injection Zone

The Permittee must calculate the critical pressure rise that is needed within each injection zone to move fluids into adjacent USDWs along a hypothetical pathway through the confining zone. For the Minnelusa injection zone, this would be the critical pressure rise needed to move injection zone fluids into the Unkpapa/Sundance and Madison at DW No.1.

2. Calculation of Injection-Induced Injection Zone Pressure

a. For each injection well, the Permittee must calculate the injection zone formation pressures resulting from 10 years of injection activity at the injection rate needed to dispose of the maximum anticipated volume of treated ISR waste fluids versus distance away from each injection well. Cumulative effects of injection from multiple wells must be considered as applicable.

b. The Permittee must compare the injection-induced pressure values calculated in Part II, Section F.2.a with the critical pressures calculated in Part II, Section F.1 to determine the distance from each injection well at which the injection-induced pressure is not greater than the critical pressure to move injection zone fluids out of the injection zone and potentially and into an USDW.

c. The Permittee must use this information to demonstrate that each injection well is located a sufficient distance away from abandoned oil and gas test wells and the Dewey Fault to prevent the potential for movement of fluids into USDWs.

d. The Permittee must use the diffusivity equation included in the Class V permit application as demonstrated by Lee, 1982, using site-specific data for the input values. At the discretion of the Director, the Permittee may use input values from published reports and must include the reference and justification for using such input values.

3. Calculation of Maximum Injection Rate for Each Class V Injection Well

a. After the Permittee has calculated the critical pressure rise for each injection zone and the injection-induced injection zone pressure according to distance from each injection well using the injection rate needed to dispose of the maximum volume of treated ISR waste fluids and 10 years of injection activity, the Permittee must calculate a maximum injection rate for each injection well. The maximum injection rate must be determined such that the critical pressure in each injection zone is not exceeded 1,000 feet away from the nearest potential breach in confining zones, as discussed in Sections 4.4.2, 5.4.3 and 7.7.2 of the Class V Area Permit Fact Sheet. This maximum injection rate must ensure that no injection zone fluids move out of the injection zone through a pathway in the confining zones.

b. The Permittee must include the maximum injection rates calculated for each Class V well in the Injection Authorization Data Package Report to be reviewed by the Director to determine the maximum injection rate permit limit for each injection well. The maximum injection rate permit limits set by the Director will be included in the Authorization to Inject document.

4. Calculation of Pressure Effects of Additional Minnelusa Injection Wells

If the Permittee constructs additional Class V injection wells that will be injecting into the Minnelusa injection zone, the critical pressure calculated under Part II, Section F.1 and the injection-induced injection zone pressure calculated under Part II, Sections F.2 must be performed taking into account the pressure effects of having more than two injection wells injecting into the Minnelusa injection zone.

5. Modification to Calculations for Extended Injection Activity

If this Permit is renewed or modified for a period longer than 10 years, calculations of critical pressure rise, injection-induced pressure, and maximum injection rate must be re-evaluated for the revised period of injection, including the effects of drawdown in the Madison aquifer under Section E.3.b and additional Minnelusa injection wells under Section F.4 of this Part.

G. Injection Well Completion Report

1. Each injection well must be constructed according to the requirements in Part III.
2. After well construction has been completed, the Permittee must submit for each Class V injection well the EPA Completion Form 7520-9 for Injection Wells with attachments. EPA Form 7520-9 can be found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators.

H. Initial Demonstration of Mechanical Integrity

1. Prior Notification Requirement

Before conducting the initial mechanical integrity tests on each Class V injection well, the Permittee must notify the Director a minimum of 30 days prior to the testing date to give the Director, or an authorized representative, an opportunity to witness the test.

2. Internal Mechanical Integrity: Tubing-Casing-Annulus (TCA) Pressure Mechanical Integrity Test

The Permittee must conduct the TCA pressure test for each injection well to demonstrate internal mechanical integrity. The TCA pressure test procedures are found at Part V, Section C.6.b.

3. External Mechanical Integrity: Cement Bond Logs of the Surface Casing and the Long String Casing

The Permittee must submit the results of the cement bond logs conducted on the surface casing and long string casing of each injection well as required under Part II, Section C, Table 3 and Table 5 to the Director for the demonstration of External Mechanical Integrity. The Cement Bond Log must demonstrate 80% bonding through the confining zones. The Director may require additional logging and testing, or remedial cementing if a Cement Bond Log does not demonstrate External Mechanical Integrity.

I. Formation Testing Involving Injection

1. The Permittee must conduct the formation tests listed in Table 10 for the purposes stated in the table.
2. Limited injection is permissible prior to receiving Authorization to Inject only for the purposes of conducting the formation testing listed in Table 10.
3. The testing procedures, results and interpretation of results must be submitted to the Director for evaluation as described in Table 10.

Table 10. Formation Testing Involving Injection

TYPE OF TEST	PURPOSE	DUE DATE
Step Rate Test	Initial test to determine site specific fracture gradient and fracture pressure to use for calculating MAIP permit limit for each well. Injection pressures must be measured at the surface and bottom hole to determine friction loss for each well.	Prior to receiving Authorization to Inject
Initial Temperature or Radioactive Tracer Survey	Baseline assessment of Part II Mechanical Integrity, and injectivity profile information.	After MAIP has been determined from the Step Rate Test, but prior to receiving Authorization to Inject

4. Step Rate Test and Determination of Maximum Allowable Injection Pressure

a. **Fracture Pressure:** The Permittee must run an injection Step Rate Test for each injection well to determine the site-specific pressure at which fractures form in the injection zone at each injection well location. During the Step Rate Test, the Permittee must monitor injection rate, surface injection pressure, and bottom hole injection pressure within 50 ft of the top of the injection zone. The Step Rate Test must be run using the injection tubing and packer. The Step Rate Test results must be submitted to the Director for evaluation.

b. **Fracture Gradient:** After fracture pressure for the injection zone has been determined based on the Step Rate Test results, the fracture gradients can be calculated according to the following formula:

$$fg=FP/d$$

FP = bottom-hole fracture pressure measured in the injection zone interval (from Step Rate Test)
fg = fracture gradient (calculated value)
d = depth to pressure sensor

c. **Maximum Allowable Injection Pressure:** The site specific maximum allowable injection pressure (MAIP) must be set at 90% of the surface pressure causing fracturing in the injection zone. The Area Permit sets a specific gravity limit of 1.0113 and this value must be used for specific gravity in the calculation. The MAIP permit limit for each injection well will be included in the Authorization to Inject approval document issued by the Director.

d. **Loss in Pressure due to Friction**: There may be a pressure loss due to friction between the injectate and the injection tubing. Step Rate Test results will determine this friction loss.

5. Initial Temperature Survey or Radioactive Tracer Survey

a. After the Step Rate Test has been conducted to identify injection zone fracture pressure, the Permittee must conduct an initial temperature survey or radioactive tracer survey for each injection well while injecting at a pressure below the injection zone fracture pressure but not below the MAIP permit limit.

b. The Permittee must take into account the pressure loss due to friction and the specific gravity of the injectate to ensure that the pressure in the injection zone is below the fracture pressure but not below MAIP.

c. The results of the test must be submitted to the Director in the Injection Authorization Data Package Report.

Recommendations for Radioactive Tracer Survey procedures can be found at the EPA Region 8 UIC website: https://www.epa.gov/uic/uic-epa-region-8.

J. Evaluation of the Injection Authorization Data Package Reports

1. Well Testing Information

The Director will evaluate the information provided in the Injection Authorization Data Package Reports and may issue a written Authorization to Inject only after finding:

a. Stratigraphic logs, aquifer potentiometric surface measurements and water quality data for the Minnelusa injection zones that demonstrate adequate confinement is present and provides hydrologic isolation of the injection zone from USDWs;

b. The laboratory analyses core samples from the Opeche Shale upper confining zone core demonstrate that confining zone permeability and hydraulic conductivity values are adequate for preventing migration of fluid out of injection zone;

c. For Madison water supply wells (if drilled): The laboratory analyses of Lower Minnelusa lower confining zone cores demonstrating that confining zone permeability and hydraulic conductivity values are adequate for preventing migration of fluid out of injection zone;

d. The TDS concentration within all Minnelusa injection zones is greater than 10,000 mg/L thus demonstrating that the injection zone is not an USDW;

e. Critical pressure rise and injection zone pressure calculations, considered together with the maximum injection rate permit limit, demonstrate that the injection well is located a sufficient distance from any feature that has the potential to serve as a pathway for fluid migration out of the injection zone into an USDW;

f. If more than one injection well is targeting the Minnelusa injection zone, the Permittee has accounted for the pressure effects of having more than one injection well in calculating the critical pressure rise, the injection-induced injection zone pressure and the maximum injection rate for each Class Vwell.

g. The well construction completion report demonstrates that each injection zone is isolated from USDWs by well casing and cement, meeting the requirements of Part III, Section D, and that there is a bond between at least 80% of the well casing and cement through the confining zones as demonstrated by the cement bond log;

h. The well perforations are located within the approved injection zone with the top perforation no less than 50 feet below the base of the lowest USDW intersecting the well bore;

i. The initial temperature survey or radioactive tracer survey provides baseline conditions for comparison with future logs required under Part V, Section C.6.c;

j. Both internal and external mechanical integrity are demonstrated for the injection well; and
k. Step Rate Test data provide the injection zone fracture pressure for the injection well allowing the Director to set a permit limit for the MAIP for the injection well calculated using the formula in Part II, Section I.4.c.

2. Pond Design Criteria and Cumulative Effects Analysis of Wellfield Operations

Before the Director will issue written Authorization to Inject, the Permittee must submit information to the Region 8 Air Program for the EPA to determine the applicability of the 40 CFR part 61 subpart W regulations, and if necessary, receive construction approval from the EPA.

PART III. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing, and packer.

A. During well construction intersected aquifers must be isolated to prevent intermingling of formation fluids.

B. Approved Well Construction Plans

The details of the approved well construction plan are summarized in Table 11 and Figure 3.

The Permittee is required to document the thickness and lithology of the Lower Minnelusa confining zone in well logs of the Madison water supply wells (if constructed), as described under Part II, Section C.

Table 11. Well Casing and Cement Summary

	Burdock
	DW No.1 (Figure 3)
Conductor Casing Size (in)	13-3/8”
Conductor Casing Depth (ft)	~60’
Surface Casing Depth (ft)	50 ft below the base of the Sundance aquifer (~970’)
Surface Casing Size (in)	9-5/8”
Surface Casing Cement Interval (ft)	From base of Surface Casing to surface (0 - ~970’)
Surface Casing Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.
Long string Casing Depth (ft)	328’ below the top of the Red Marker (~2,355’)
Long string Casing Size (in)	7” or 5-1/2”
Long string Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.
Long string Cement Interval (ft)	From base of Long string Casing to surface (0’ - ~2,355’)
Total Depth (ft)	~328’ below the top of the Red Marker (~2,355’)

FIGURE 3

PERMIT REVIEW WORKSHEET

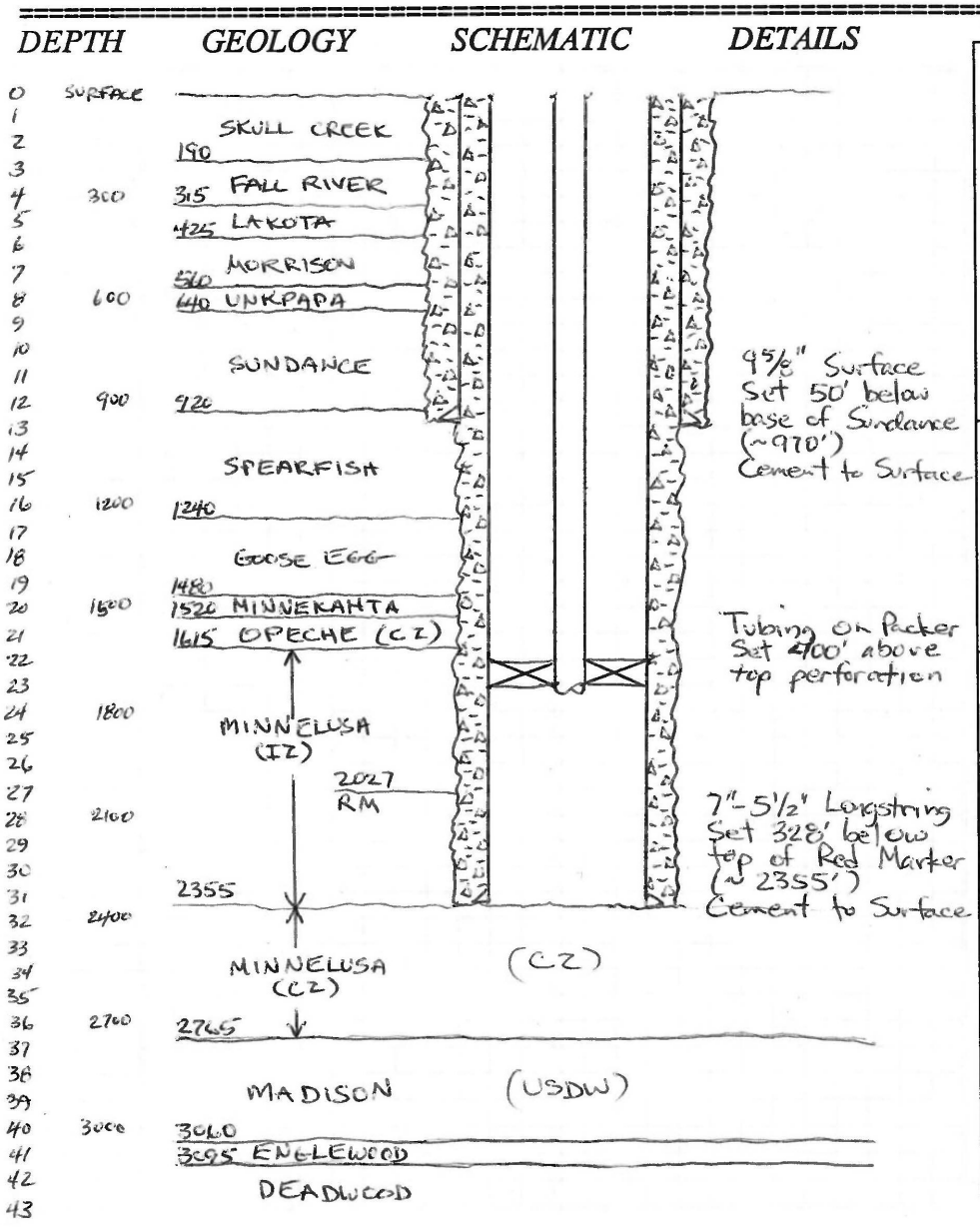
WELL NAME Dewey Burdock DW#1 OPERATOR Powertech

S 2 T 7S R 1E Fall River COUNTY, SD

CATEGORY : ☐ RA ☑ NEW CONSTRUCTION ☐ NEW CONVERSION from _____

LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND

WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD Class V



LOGS
- ☐☐ CBL/VDL/γ-RAY
- ☐☐ OAL
- ☐☐ CASING INSP
- ☐☐ RTS
- ☐☐ TEMP
- ☐☐ DIL
- ☐☐ γ-RAY
- ☐☐ RESISTIVITY
- ☐☐ CONDUCTIVITY
- ☐☐ SP
- ☐☐ SONIC (ϕ)
- ☐☐ N-DENSITY
- ☐☐

TESTS
- ☐☐ PORE PRESSURE
- ☐☐ PERMEABILITY
- ☐☐ IZ SAMPLE
- ☐☐ SOURCE SAMPLE
- ☐☐ SRT
- ☐☐ MIT
- ☐☐

C/A
- ☐☐ PRESSURE LIMIT
- ☐☐ REMEDIAL CMT

WELLHEAD EQUIP
- ☐☐ GAUGES
- ☐☐ STAB GAUGES
- ☐☐ FLOWMETER
- ☐☐ RATE INDICATOR
- ☐☐ SAMPLE TAP
- ☐☐

OPERATION
- ☐☐ COMPLETION RPT
- ☐☐ WORKOVER RPT
- ☐☐ AE _____
- ☐☐ Vmax _____
- ☐☐ Pmax _____
- ☐☐ MON _____
- ☐☐ RPT _____

PERMIT NUMBER SD52173-08764

FIGURE 3 – DW No. 1 Well Construction Schematic

C. Changes to Approved Well Construction Plans

1. Changes in construction plans during construction may be approved by the Director as minor modifications (40 CFR § 144.41). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director in accordance with 40 CFR § 144.52(a)(1).
2. After initial well construction is complete, any subsequent changes in well construction that are different from approved specifications described under Part III of this Area Permit will require a modification in accordance with 40 CFR § 144.39, § 144.41, and § 124.5.
3. After well construction has been completed, the Permittee must submit for each Class V injection well EPA Form 7520-9 *Completion Form for Injection Wells* with attachments. EPA Form 7520-9 is found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators.

D. Casing and Cement

1. The well or wells must be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water.
2. The well casing and cement must be designed for the life expectancy of the well.
3. The Permittee must isolate all USDWs by placing cement between the outermost casing and the well bore;
   a. The Permittee must isolate the injection zone by placing sufficient cement to fill the calculated space between the casing and the well bore from the total depth (TD) to the surface; and
4. The Permittee must use cement:
   a. Of sufficient quantity and quality to withstand the maximum operating pressure; and
   b. Which is resistant to deterioration from formation and injection fluids; and
   c. In a quantity no less than 120% of the calculated volume necessary to cement off a zone.
5. A float shoe may be used with a float collar one or two joints up from the bottom of the casing as field conditions dictate.
6. Centralizers must be placed at a minimum of one on every fifth casing joint.
7. The Director may require remedial cementing if it is shown to be inadequate by a cement bond log or other demonstration of external mechanical integrity.

E. Well Casing Perforations

1. Perforation of an injection well must not be conducted until after:
   a. All logs and tests have been performed to identify the depths of the injection zone and confining zones; and
   b. The logs and tests have been analyzed by a knowledgeable log analyst to correctly identify the extent of the injection zone for each well.
2. The top perforation must be no higher than the approved top of the injection zone and at least 50 feet below the base of the lowermost USDW intersecting the well bore.
3. Additional perforations may be added to an approved injection zone after initial construction is complete in accordance with Part IV, Section F.3.

F. Injection Tubing and Packer

1. All Class V deep wells constructed under this Area Permit must inject fluids through tubing with a packer set immediately above the injection zone. The packer must be set no more than 100 feet above the uppermost perforation in the approved injection zone. The packer setting depth may be changed provided it remains no more than 100 feet above the uppermost perforation in the approved injection zone and the Permittee provides notice and obtains the Director's approval for the change.

2. The tubing and packer must be designed for the expected service.
3. The tubing and packer must be chemically compatible with injected fluids.

G. Tubing-Casing Annulus (TCA) Fluid

1. The annulus space between the injection tubing and the well casing must be sealed and filled with fresh water containing a corrosion inhibitor.
2. The annulus fluid may contain additives as deemed necessary by the Permittee. A description of annulus fluid additives must be included in the well construction report.
3. The Permittee must notify the Director prior to any changes being made to the annulus fluid additives.

H. Sampling and Monitoring Devices

1. The Permittee must install and maintain in good operating condition at the wellhead:
   a. A fluid sampling point located at a conveniently accessible location at the wellhead to enable collection of representative samples of the injectate;
   b. Pressure gauges measuring injection pressure and annulus pressure;
   c. One-half (1/2) inch stab or threaded fittings, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to at least 500 psi above the Maximum Allowable Injection Pressure (MAIP) specified in Part IV, Section H:
      i. on the injection tubing; and
      ii. on the tubing-casing annulus;
   d. Continuous recording devices located to monitor and record injection pressure, TCA pressure, injection rate, and cumulative volume.
   e. A crown valve on the wellhead that will allow a lubricator and well logging equipment to be rigged up and run into the well while the well remains on injection.
   f. A pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when the MAIP specified in Part IV, Section H is exceeded at the wellhead.
   g. Protective automated monitoring and shutoff system with control switches to notify the operator in the event that any of the Area Permit conditions related to minimum or maximum permit limits are met. The system must be designed to cause injection operations to cease until the problem is identified and corrected.
2. A diagram of the preliminary wellhead schematic diagram is included as Figure A-1 in Appendix A of this Area Permit. The Permittee must submit to the Director an as-built final wellhead schematic diagram as part of the well construction completion report.

I. Surface Facilities

A diagram of the proposed surface facilities to which the Class V injection wells will be connected is included as Figure A-2 in Appendix A or this Area Permit. The Permittee must provide an as-built final schematic diagram of the surface facilities as part of the well construction completion report.

J. Requirements for Adding Injection Wells DW No. 2, DW No. 3, and DW No. 4 to this Area Permit

1. The Permittee must not construct wells DW No. 2, DW No. 3, and DW No. 4 under this Area Permit until construction has been approved in accordance with the procedures under this Section.

2. Prior to constructing additional wells under this Area Permit, the Permittee must seek authorization to construct by submitting the following materials to the Director:
   a. a cover letter requesting authorization to construct the well and referencing Area UIC Permit **SD52173-00000**;
   b. a completed EPA 7520-6 injection well application form for each well;
   c. a wellbore diagram of the proposed injection wells;
   d. a topographic map showing the location of the additional wells within the Dewey-Burdock Project Area; and
   e. a list of all wells penetrating the Confining Zone within the Area of Review (AOR) of the new wells including cementing records and cement bond logs for any new wells within the AOR not previously evaluated by the EPA.
   f. Submittal of estimates for well plugging according to the terms in this permit.
   g. Submittal of evidence for Financial Responsibility according to the terms in this permit.
3. Once the EPA has confirmed that the proposed injection well meets permit conditions, the Director will authorize construction by written communication to the Permittee.
4. This Area Permit authorizes the Permittee to construct and test wells only in accordance with the terms and conditions of this Permit.

K. Postponement of Construction

1. The Permittee must present an annual Area of Review (AOR) update to the Director until construction of the Class V injection wells commences. The AOR update must include identifying the location, depth, completion interval, and, if applicable, evidence that the Minnelusa injection zone was isolated for any new wells within the permit area. This update will be due and included as part of the Annual Reporting describe in Table 15.
2. In order to obtain authorization for construction and operation of wells DW No. 2, DW No. 3, and DW No. 4, the Permittee must follow the permit requirements under Part II of this Area Permit.
3. If authorization for DW No. 2, DW No. 3, and DW No. 4 is added to this Area Permit, there is no requirement for the Permittee to commence construction of the well within one year of authorization of the additional well(s).

L. Well Stimulation, Workovers and Alterations

1. Well stimulations, workovers, and alterations must meet all conditions of the Permit. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, and packer) or injection formation.
2. Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee must give advance notice to the Director. Any modification to well construction that is different from the approved specifications described under Part III of this Area Permit will require a modification of this Area Permit in accordance with 40 CFR § 144.39, § 144.41, and § 124.5.
3. The Permittee must record all work done on a Well Rework Record (EPA Form 7520-12) found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators, and must submit a revised well construction diagram, when the well construction has been modified. The Permittee must provide this and any other records of well workover, logging, or test data to the Director within thirty (30) days of the completion of the activity.

4. A successful demonstration of internal mechanical integrity is required following the completion of any well workover or alteration which affects the integrity of the casing, packer or tubing. Injection operations must cease until the well has successfully demonstrated mechanical integrity. Documentation of mechanical integrity test results must be included in the next Quarterly Monitoring Report, or sooner if the Permittee chooses. Injection operations must not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.
5. If an acidizing operation is conducted on well perforations, then a temperature survey log must be conducted to verify that the integrity of cement above the perforations has not been compromised by exposure to the acid. Documentation of temperature survey log results must be included in the next Quarterly Monitoring Report.

PART IV. WELL OPERATION

A. Injection between the outermost casing protecting USDWs and the well bore is prohibited.

B. The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into an USDW, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may otherwise adversely affect the health of persons.

C. Requirements Prior to Commencing Injection.

1. Injection operation is prohibited for an injection well until the requirements herein have been met and the Director issues a written Authorization to Inject.
2. The Permittee must not commence injection until:
   a. The Permittee has submitted the Injection Approval Data Package to the Director for evaluation;
   b. The Permittee has submitted the results of the Step Rate Test and the Director has set a MAIP for the injection well;
   c. The Permittee has submitted the results from the initial temperature survey or Radioactive Tracer Survey to the Director for evaluation; and
   d. The Director has issued the written Authorization to Inject.

D. Mechanical Integrity

1. The Permittee is required to ensure each injection well maintains mechanical integrity at all times. Injecting into a well that lacks mechanical integrity is prohibited. An injection well has mechanical integrity if:
   a. There is no significant leak in the casing, tubing, or packer (Internal Mechanical Integrity); and
   b. There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (External Mechanical Integrity).
2. The methods for demonstrating mechanical integrity are found in Part V, Section C.6 of this Area Permit. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations must be made.

E. Requirements if the Injection Zone is an USDW

This Permit does not authorize injection into USDWs. If any Minnelusa injection zone is determined to be an USDW based on testing, the Permittee must obtain an aquifer exemption and a major permit modification according to the requirements of 40 CFR § 144.39 and § 124.5 in order to inject into the Minnelusa formation.

F. Approved Injection Zone and Perforations

1. The Permittee must not perforate an injection well until after:
   a. All logs and tests have been performed to identify the depths of the injection zone and confining zones, and
   b. The logs and tests have been analyzed by a knowledgeable log analyst to correctly identify the extent of the injection zone for each well.
2. Injection is allowed only within the approved injection zone depths based on well drill hole logs and only after the Director has issued written Authorization to Inject. The approximate depth to the injection zone for well DW No. 1 is shown in Table 1 of this Area Permit. The site-specific depth to each injection zone for each well under the Area Permit will be established by the well logging required under Part II, Section C. The approved top of each injection zone must be no less than 50 feet below the base of the lowest USDW intersected by the well bore. The Authorization to Inject will include the actual top and bottom depths of the approved injection zones based on well open hole logs.
3. Additional injection perforations may be added once the following requirements are met:
   a. The Permittee provides notice to the Director in accordance with Part III, Section L for well Workovers and Alterations. The Permittee must also follow the requirements for the Injection Pressure Limit found in Part IV Section H, which may result in a change to the permitted MAIP.
   b. The new perforations must remain within the approved injection zone,
   c. The top perforation is no higher than the approved top of the injection zone,
   d. Fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and
   e. The Permittee has received approval from the Director for the perforations.
4. After the addition of perforations, the Permittee must follow the requirements for well Workovers and Alterations under Part III, Section L.
5. In no case shall the operation of the injection well cause the movement of injected or formation fluids outside of the approved injection zone.

G. Injectate Specific Gravity Limit

The injectate specific gravity must not exceed 1.0113.

H. Injection Pressure Limit

1. Except during stimulation injection, pressure at the wellhead must not exceed a maximum which must be calculated to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone.
2. In no case shall injection pressure cause the movement of injection or formation fluids into an USDW.
3. The permitted MAIP, measured at the wellhead, must be established based on site-specific conditions at each injection well location according to Part II, Section I.4. The MAIP for each Class V injection wells will be included in the Authorization to Inject.
4. The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director to ensure that the requirements in paragraph 1 above are fulfilled. The Permittee may be required

to conduct a Step Rate Test or other suitable test to provide information for determining the fracture pressure and fracture gradient of the injection zone.

I. Injection Volume Limit

Because there is no aquifer exemption area associated with this Area Permit, there is no injection volume limitation.

J. Injection Rate Limit

The monthly average injection rate must not exceed the injection rate limits approved by the Director in the written Authorization to Inject based on calculations under Part II, Section F.3.

K. Approved Injectate

1. Injection fluid is limited to waste fluids from the ISR process generated by the Dewey-Burdock Project. These waste fluids include groundwater produced from well construction, laboratory waste fluids, well field production bleed, concentrated brine generated from the reverse osmosis treatment of groundwater produced from the well field during groundwater restoration, restoration bleed not processed by reverse osmosis, yellowcake wash water, bleed from effluent and precipitation circuits, sumps, membrane cleaning solutions, groundwater sweep solutions, and plant washdown water. The groundwater pumped from any portion of the Inyan Kara aquifers for the purpose of remediating an excursion is also approved for injection into the Class V injection wells.
2. The injection of fluids with constituent concentrations above the hazardous waste or radioactive waste concentration limits is prohibited. The injectate must meet the permit limits set in Part V, Section D.2.a, Table 14.

L. Tubing-Casing Annulus (TCA) Pressure

The Permittee must ensure that the TCA fluid is maintained under an induced pressure at all times. The tubing-casing annulus pressure must be maintained at a minimum of 100 psi above the injection pressure. If this pressure cannot be maintained, the Permittee must cease injection and inspect the long string casing, cement and the injection tubing and test for mechanical integrity.

PART V. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

A. Annual Pressure Falloff Test

1. The pressure falloff test must be conducted initially within one year after injection begins and annually thereafter. If the well has not injected since the previous pressure falloff test was conducted, another pressure falloff test is not required until injection begins again. The time interval for each test should not be less than nine (9) months or greater than 15 months from the previous test to ensure that the tests will be performed at relatively even intervals throughout the life of the injection well. The falloff testing report should be submitted to the Director no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the Area Permit and may result in an enforcement action. Any exceptions should be approved by the Director prior to conducting the test.
2. The Permittee is required to prepare a plan for running the yearly pressure falloff test. The Permittee must use the EPA guidelines to develop a site-specific plan. The “UIC Pressure Falloff Testing Guideline” is found at https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf. The final test plan must

be submitted to the Director for review at least 30 days prior to conducting the annual pressure falloff test.

3. The Permittee must follow the same test procedure for the initial and subsequent tests, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. The Permittee must analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and an estimate of the well skin effect and reservoir flow conditions. The report must also compare the test results with the previous year's test data, unless it is the first test performed at that well, and must be prepared by a knowledgeable analyst.

B. Seismicity

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service known as the Earthquake Notification Service (ENS), which reports real-time earthquake events for any area specified by the user. Details for the ENS can be found at: **https://earthquake.usgs.gov/ens/.**

The Permittee must subscribe to this service and check daily for notification emails from the service. The Permittee must notify the Director within twenty-four (24) hours of any seismic event measuring 4.5 magnitude (MMI scale) or greater reported within two miles of the permit.

1. If any seismic event of magnitude 4.5 (MMI scale) or greater is reported within two miles of the permit boundary, the Permittee must immediately cease injection.
2. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes.
3. Injection must not resume until the Permittee has obtained approval to recommence injection from the Director.
4. The Permittee must record any seismic event measuring 2.0 magnitude (MMI scale) or greater occurring within fifty miles of the permit boundary and report such events to the Director on a quarterly basis.

C. Ongoing Demonstration of Mechanical Integrity

1. The Permittee must demonstrate mechanical integrity prior to commencing injection and periodically thereafter. The schedule for ongoing demonstration of mechanical integrity is shown in Table 12.

Table 12. Schedule for Ongoing Demonstration of Mechanical Integrity

Well Status	Schedule for Demonstration of Mechanical Integrity
Actively Injecting Well	5 years from last successful demonstration of mechanical integrity
Temporarily Abandoned Well (no injection for 24 consecutive months)	Before the end of 24 months of no active injection and every 2 years from the last successful demonstration of mechanical integrity

2. In addition to these regularly scheduled demonstrations of Mechanical Integrity, the Permittee must demonstrate Internal Mechanical Integrity following any workover which affects the tubing, packer or casing per Part III, Section L.

3. The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity.

4. Mechanical integrity test results must be submitted to the Director with the next Quarterly Report after completion of the tests, unless the test was conducted within 60 days of the Quarterly Report due date. In that case, mechanical integrity test results must be included in the subsequent Quarterly Report.

5. Notification Prior to Testing

a. Before conducting the regularly scheduled mechanical integrity tests on each Class V injection well, the Permittee must notify the Director a minimum of 30 days prior to the testing date to give the EPA an opportunity to witness the test. The Director may allow a shorter notification period if it would be sufficient to enable the EPA to witness the mechanical integrity test.

b. When the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, any prior notice is sufficient.

c. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

6. Mechanical Integrity Test Methods and Criteria

a. EPA-approved methods must be used to demonstrate mechanical integrity. The Permittee must refer to recommendations for well test procedures found at https://www.epa.gov/uic/uic-epa-region-8.

b. Internal Mechanical Integrity: TCA Pressure Mechanical Integrity Test Procedure

The Permittee must conduct the following internal mechanical integrity test to verify there are no leaks in the well tubing, casing or packer.

i. Stabilize well pressure and temperature.
ii. Install ball valve or similar type of "bleed" valve on annulus gate valve.
iii. Pressurize annulus to a minimum of 100 psig with liquid and shut-in pump side gate valve. If typical operating annulus pressures are above 100 psi, higher pressures acceptable to the Director and compatible with the well completion configuration will be used. The pressure to be used will be detailed in proposed procedures supplied with notification of testing.
iv. Install calibrated and certified gauge on "bleed" type valve. The annulus may need to be pressurized and bled off several times to ensure an absence of air.
v. Monitor and record pressure for one hour.
vi. For a test to pass, the pressure may not fluctuate more than 10 percent during the one-hour test.
vii. At the conclusion of the test, lower the annulus pressure to normal operating pressure.

c. External Mechanical Integrity

The Permittee must conduct a temperature survey or a radioactive tracer survey in accordance with Table 12 to assess the ability of the cement behind the long string casing to prevent movement of injected fluids out of the approved injection formations.

7. Unanticipated Loss of Mechanical Integrity

a. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as increase of pressure in the annulus, water flowing at the surface, etc.), the Permittee must verbally notify the Director within 24 hours (see also Part VII, Section D.11.e of this Permit), and the well must be shut-in within 48 hours unless the Director requires immediate shut-in.

b. Within five days, the Permittee must submit a follow-up written report that documents circumstances that resulted in the mechanical integrity loss and how it was addressed. If the mechanical integrity loss has not been resolved, the report should include the proposed plan to reestablish mechanical integrity.
c. Injection operations must not be resumed until after the well has successfully demonstrated mechanical integrity pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.
d. The annulus pressure must be maintained at a minimum of 100 psi above the injection pressure.

D. Monitoring Methods, Parameters and Frequency

1. Monitoring Methods

a. Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements must be representative of the activity or condition being monitored.
b. Injectate samples must be collected at a location between the last treatment process and the injection wellhead.
c. The analytical methods included in Table 14 must be used for injectate sample analysis. Except as may be required by the analytical method(s) shown in Table 14, injectate samples must be analyzed for dissolved fractions. Equivalent methods or total recoverable analysis may be used after prior approval by the Director.
d. Injection pressure, annulus pressure, injection rate, and cumulative injected volumes must be observed and recorded under normal operating conditions, and all parameters must be observed simultaneously to provide a clear depiction of well operation.
e. Pressures are to be measured in pounds per square inch (psi).
f. Fluid volumes are to be measured in standard oilfield barrels (bbl) or gallons (gal).
g. Fluid rates are to be measured in barrels per day (bbl/day) or gallons per minute (gpm).

2. Monitoring Parameters and Frequency

a. Injectate Monitoring

i. The injectate must be monitored as required in Tables 13 and 14.

Table 13. Injectate Sampling Requirements

Injectate Parameter	Purpose	Frequency
Injected Fluid Sample Analysis Specific Gravity	To determine if the injected fluid meets permit limit for specific gravity shown in Table 14.	Weekly
Injected Fluid Water Sample Analysis	To determine if the injected fluid meets permit limits in Table 14.	Quarterly and whenever there is a change in the waste stream

Table 14. Analytes to Monitor in Injectate, Reporting Units, Permit Limits and Analytical Methods

Analyte	Reporting Units	Permit Limit[1]	Analytical Methods
Arsenic	mg/L	5.0	E200.8
Barium	mg/L	100.0	E200.8
Cadmium	mg/L	1.0	E200.8
Chromium	mg/L	5.0	E200.8
pH	pH units	>2 and <12.5	A4500-H B
Lead	mg/L	5.0	E200.8
Lead-210	pCi/L	10	E905.0 Mod.
Mercury	mg/L	0.2	E200.8
Polonium-210	pCi/L	40	RMO-3008
Radium (Total)	pCi/L	60	E903.0/E904.0
Radium-228	pCi/L	60	E904.0
Specific Gravity	Ratio to density of water	1.0113	ASTM D1429-13, SM 2710F
Selenium	mg/L	1.0	E200.8, A3114 B
Silver	mg/L	5.0	E200.8
Sulfate	mg/L	None	A4500-SO4 E; E300.0
TDS	mg/L	None	A2540C
TSS	mg/L	None	EPA 160.2
Thorium-230	pCi/L	100 pCi/L	ATSM D3972-90M
Uranium	mg/L	None	E200.7, E200.8
Uranium (Natural)	pCi/L	300 pCi/L	ATSM D3972-90M

[1] Permit limits for metals and radionuclides are for dissolved fractions.

ii. If thorium -230, lead-210 and polonium-210 are not detected in the waste stream after the first four quarters, the Permittee is not required to analyze for thorium-230, lead-210 and polonium-210 in subsequent quarters. If a new wellfield is brought online, then analysis will be required for the full suite of analytes, including thorium-230, lead-210 and polonium-210. If thorium-230, lead-210 and polonium-210 are not detected in the modified waste stream after the first four subsequent analyses, thorium -230, lead-210 and polonium-210 analyses will not be required for subsequent monitoring until a new wellfield is brought online.

iii. A waste stream change, as referenced in Table 13 above, consists of a new waste stream being added to the injectate such as:

A) a new well field coming on line;
B) aquifer restoration beginning in a well field;
C) when laboratory fluid wastes are added in for the first time; or
D) a new laboratory procedure or laboratory chemical is used.

b. Monitoring of Well Operating Parameters

The parameters listed in Table 15 are to be monitored as indicated in Table 15 even during periods when the well is not operating.

3. Monitoring, Recording and Reporting Schedules

The monitoring information listed in Table 15 must be recorded and reported according to the schedules listed below.

Table 15. Monitoring, Recording and Reporting Requirements for Well Operating Parameters

A.	CONTINUOUS MONITORING
MONITOR	Injection Rate (bbl/day or gpm)
	Injection Pressure (psig)
	Cumulative Injected Volume (bbl or gal)
	TCA Pressure (psig)
	Differential Pressure between Injection Pressure and TCA Pressure
	Seismic events greater than or equal to 2.0 (MMI Scale) within a fifty (50) mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website.
RECORD	Monthly for Cumulative Injected Volume Daily for other parameters Seismic events greater than or equal to 2.0 (MMI Scale) within fifty (50) miles of the project Boundary.
REPORT	Include in Quarterly Report

B.	WEEKLY MONITORING
OBSERVE	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is actively injecting. If annulus pressure falls below 100 psi above the injection pressure, or changes more than 10% within a week, observe TCA fluid level at that time and determine why the differential pressure fell below permit limits.
RECORD	TCA fluid level for active injection well. Any additions or subtractions of fluid to/from the annulus head tank.
ANALYZE	Samples of injectate fluid for specific gravity at the Dewey and the Burdock sites.
REPORT	Include in Quarterly Report

C.	TWICE MONTHLY MONITORING
OBSERVE	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is NOT actively injecting, if pressure decreases by more than 10% within a month, observe TCA fluid level at that time and determine why the differential pressure fell below permit limits.
RECORD	TCA fluid level for wells NOT actively injecting, when pressure decreases by more than 10% within a month. Any additions or subtractions of fluid to/from the annulus head tank.
REPORT	Include in Quarterly Report

D.	MONTHLY MONITORING
RECORD	Maximum, minimum and average values for Injection Pressure (psig)
	Maximum, minimum and average values for Annulus Pressure (psig)
	Maximum, minimum and average values for Daily Injection Rate (bbl/day or gpm)
	Maximum, minimum and average values for Injected Fluid Specific Gravity
	Injected volume for that month (bbl or gal)
	Cumulative volume of injectate for that month (bbl or gal)
	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is NOT actively injecting
REPORT	Include in Quarterly Report

E.	MONITORING IF WASTE STREAM CHANGES
ANALYZE	Injectate fluid for the analytes listed above using the analytical methods shown in Table 14. Equivalent analytical methods may be used with prior approval from the Director.
REPORT	Within 30 days of sample collection

F.	QUARTERLY MONITORING
ANALYZE	Injectate fluid for the analytes listed above using the analytical methods shown in Table 14. Equivalent analytical methods may be used with prior approval from the Director.
REPORT	Monthly average, maximum, and minimum values for Injection Pressure (psig)
	Monthly average, maximum, and minimum values for Annulus Pressure (psig)
	Monthly average, maximum, and minimum values for Daily Injection Rate (bbl/day or gpm)
	Monthly average, maximum, and minimum values for Injected Fluid Specific Gravity
	Injected volume for each month during the quarter (bbl or gal)
	Cumulative volume injected since the well began injection operations (bbl or gal)
	Results of injectate fluid analysis in units shown in Table 14.
	Summary of monthly reviews of seismic events greater than or equal to 2.0 (MMI Scale) within a fifty (50) mile radius of the Area Permit boundary.

G.	ANNUAL MONITORING
ANALYZE	Conduct pressure falloff test. Submit plan to the Director a minimum of 30 days in advance of the falloff test. Use EPA guidelines to develop a site-specific plan. "UIC Pressure Falloff Testing Guideline" is found at https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf. The Permittee must follow the same test procedure for the initial and subsequent tests, so that valid comparisons of reservoir pressure, permeability, and porosity can be made.
REPORT	The Permittee must analyze test results and provide a report, prepared by a knowledgeable analyst, with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report must also compare the test results with previous year's test data, unless it is the first test performed at that well. The Permittee must report any changes to wells within the Area of Review (newly drilled wells, depth changes for existing wells, or alterations to plugged wells) made during the reporting year.

H.	MONITORING EVERY TWO YEARS
ANALYZE	Conduct Internal and External Mechanical Integrity Tests before the end of 24 months of non-injection if a well has not been used for injection for 24 consecutive months
REPORT	Mechanical Integrity Test (MIT) results in next Quarterly Report unless the MIT was conducted within 60 days before the due date of the next Quarterly Report. In that case, the MIT results shall be due in the following Quarterly Report. A failed MIT must be reported verbally within 24 hours with a written report due in 5 days.

I.	MONITORING EVERY FIVE YEARS
ANALYZE	Conduct Internal and External Mechanical Integrity Tests within five (5) years from previous successful demonstration of mechanical integrity.
REPORT	Mechanical Integrity Test results in next Quarterly Report unless the MIT was conducted within 60 days before the due date of the next Quarterly Report. In that case, the MIT results must be due in the following Quarterly Report. A failed MIT must be reported verbally within 24 hours with a written report due in 5 days.

4. Monitoring Records

Monitoring records must include:

a. The date, exact place, and time of sampling or measurements;
b. A description of how the sample was collected;
c. The individual(s) who performed the sampling or measurements;
d. The date(s) analyses was performed;
e. The individual(s) who performed the analyses;
f. The analytical techniques or methods used; and
g. The results of such analyses.

E. Records Retention

1. Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit must be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended at any time prior to its expiration by request of the Director.
2. Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6). The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee must continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.
3. The Permittee must notify the Director as to the location where injection well records are maintained. The Permittee must notify the Director within 30 days if this location changes.

F. Quarterly Reports

Following authorization to begin injection, the Permittee must submit Quarterly Reports to the Director summarizing the results of the monitoring required above, and whether the well is operating or not. Reporting periods and due dates for Quarterly Reports are shown in Table 16. EPA Form 7520-8 *Injection Well Monitoring Report* (found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators) may be used to submit the Quarterly Reports, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Table 16. Reporting Periods and Due Dates for Quarterly Reports

REPORTING QUARTER	REPORTING PERIOD	REPORT DUE TO THE DIRECTOR
1st Quarter	January 1 – March 31	May 15
2nd Quarter	April 1 – June 30	August 15
3rd Quarter	July 1 – September 30	November 15
4th Quarter	October 1- December 31	February 15

G. Protective Automated Monitoring and Shut-Off Devices

1. Injection activities at each Class V deep injection well must be monitored with an automated control system with control switches to notify the operator if certain operating conditions are encountered. A high injection pressure switch (set at or below the Area Permit maximum) and a low annulus differential pressure switch (set above the Area Permit minimum) must shut-off injection pump power and notify the operator so that the well can be fully isolated and secured.
2. In the event that any of the Area Permit conditions related to minimum or maximum set points are met, injection operations must cease until the problem is identified and corrected. The system must not be manually restarted by an operator until compliance is verified.
3. The automated control system must operate continuously except in the event of power failure, when all well operation activities must halt.
4. Any alarms, automatic shutdowns due to permit limits and power failures must be recorded in a narrative, along with causes and actions taken to correct the situation, and included in the next Quarterly Report.
5. If fluid injection occurs during the period of any week, annulus fluid level shall be visually monitored a minimum of once per week at the annulus fluid head tank by the use of a level indicator or a sight glass. Any additions or subtractions of fluid from the annulus tank shall be recorded for monitoring purposes and reported on a quarterly basis per permit requirements.
6. *Monthly operator inspections*: If fluid injection occurs during the period of any month, a trained operator must physically visit the site to inspect the facility at a minimum frequency of not less than once per month. This inspection must verify the correct operation of the remote monitoring system by review of items such as, but not limited to, a comparison of the values shown on mechanical gauges with those reported by the remote operating system.
7. *Weekly operator inspections*: Unless annulus pressure changes by more than 10 percent per week while the well is injecting, only one annulus fluid level per week must be required to be observed, recorded and reported when injection takes place.

8. *Annulus tank fluid level measurements*: When the well is not actively being used for injection, one annulus tank fluid level measurement must be taken, recorded and reported per month unless annulus fluid pressure decreases more than 10 percent per month. In such cases of increased annulus pressure change, annulus fluid level measurements must be taken, recorded and reported twice per month.
9. When not in use by a trained well operator, offloading connections must be secured and must be locked at the valves leading to wastewater tanks so that access is restricted to trained well operators.
10. In the event of well shut down, it may become necessary to transport treated ISR waste fluids (injectate) by truck to an alternate Class V injection well site within the proposed Class V Area Permit area. Offloading of fluid from transports must only occur with a trained operator physically present on site. A waste related log sheet and/or waste manifest file will be maintained documenting that a trained well operator allowed fluid to be unloaded. At a minimum, waste log entries are to include operator name, date, time, truck identification and approximate volume.
11. If the proposed Dewey-Burdock Class V injection wells are monitored and operated remotely, the following special conditions shall be applicable to each well. (For the purpose of this permit, remote monitoring is defined as injection into the wells when a trained operator is not present at the well site or in the monitoring control room but is still able to receive shut-down alarms and is still able to physically respond to the well controls or the wellhead within 15 minutes of a compliance alarm condition.)
    a. *Local operating system and remote monitoring system:* If remote monitoring is to be used to operate the well, an automatic paging system must be installed that is designed to alert designated on-call, off-site personnel in the event of a well alarm or shut-in. The paging system will be equipped with a back-up power supply.
    b. *Response to automatic shut-downs related to a Permit condition:* Automatic shut-downs of the operating well related to Area Permit compliance limits established for well operation must be investigated on-site by a trained operator within three (3) hours of pager notification of the occurrence.
    c. *Loss of power to the control system:* In the event that a power failure beyond the capability of the back-up power supply shuts down the control system, the well must be automatically shut-in.
    d. *Loss of dial tone:* If the automatic pager cannot get a dial tone for 90 minutes, the well must automatically be shut-in.
    e. *Restart of the well after an automatic shut-in:* Restart of the well after a shut-in related to an Area Permit condition alarm (including, but not limited to, injection pressure, annulus differential pressure, loss of dial tone for more than 90 minutes or control system power failure) shall require the physical presence of the operator to verify compliance before the well can be restarted.
    f. *Restart of the well after shut downs unrelated to a Permit condition:* If the well is shut-in for more than 48 hours for circumstances unrelated to Permit conditions, restart of the well shall require the physical presence of the operator.

PART VI. PLUGGING AND ABANDONMENT

A. Requirement for Director's Approval before Plugging and Abandonment of Class V Deep Injection Wells

The Permittee must not commence plugging and abandonment of a Class V Deep injection well until after receiving written authorization from the Director.

B. Notification of Well Abandonment, Conversion or Closure

The Permittee must notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project. Notification must include:

1. The status of Class III wellfields;
2. The number and status of Class III wells that have not been plugged and abandoned as required under the UIC Class III Area Permit; and
3. Any anticipated change to the approved plugging and abandonment plan.

C. Well Plugging Requirements

1. The well must be plugged in accordance with the Approved Plugging and Abandonment Plan and with 40 CFR § 146.10.
2. Prior to abandonment, the injection well must be plugged with cement in a manner which prevents the movement of fluids into or between underground sources of drinking water.
3. Prior to placement of the cement plug(s) the well must be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

D. Approved Plugging and Abandonment Plan

The Permittee must take the following steps prior to abandonment of the Class V wells:

1. Tubing, packer and other downhole apparatus must be removed.
2. A Cement Bond Log test must be run to evaluate the cement outside the outermost casing.
3. A temperature survey test must be done to confirm external mechanical integrity, if it has been more than 2 years since the last test was run. If any pathways are discovered in the external casing cement, then remedial cementing will be required.
4. A pressure falloff test must be run if it has been more than 6 months since the last test.
5. Each well will be filled with cement from total depth to surface using a minimum of two cementing stages with enough cement to fill calculated volume of inner casing.
6. Within sixty (60) days after plugging, the Permittee must submit a Plugging Record (EPA Form 7520-14) to the Director.
7. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation.

E. Changes to the Approved Plugging and Abandonment Plan

Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to the well being plugged.

F. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee must submit a report (EPA Form 7520-14) to the Director. The plugging report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:

1. A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or
2. Where actual plugging differed from the approved plugging and abandonment plan, an updated, approved version of the plan, on the form supplied by the Director, specifying the differences.

G. Inactive Wells

After any period of 24 months during which there is no injection activity for a well, the Permittee must:

1. Provide written notice to the Director at the end of 24 months of no injection activity;
2. Demonstrate internal and external mechanical integrity before the end of 24 months of no injection activity; and
3. Describe any other actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. In addition to demonstration of mechanical integrity, these actions must include demonstration of Financial Responsibility and any other applicable permit requirements designed to protect USDWs.

PART VII. CONDITIONS APPLICABLE TO ALL PERMITS

A. Changes to Permit Conditions

1. Modification, Reissuance or Termination

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR § 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class V injection well to a non-Class V or non-injection well. Conversion to another injection well class must not proceed until the Permittee receives a major modification to this Area Permit according to 40 CFR § 144.39 and § 124.5, which would invoke the public review process required under 40 CFR part 124. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice must adequately demonstrate that the financial responsibility requirements of 40 CFR § 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee

and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the Permittee changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

B. Severability

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

C. Confidentiality

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR part 2 (Public Information).

Claims of confidentiality for the following information will be denied:
- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

D. General Permit Requirements

1. Duty to Comply

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; Permit termination, revocation and reissuance, or modification; or denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in section 1423 of the SDWA.

2. Continuation of Expiring Permits

a. Duty to Reapply. If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least 180 days before this permit expires.

b. Permit Extensions. The conditions of an expired permit may continue in force in accordance with 5 U.S.C. § 558(c) until the effective date of a new permit, if:

   i. The Permittee has submitted a timely application which is a complete application for a new permit; and

   ii. The Director, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

c. Enforcement. When the Permittee is not in compliance with the conditions of the expiring or expired permit the Director may choose to do any or all of the following:

i. Initiate enforcement action based upon the permit which has been continued;

ii. Issue a notice of intent to deny the new permit. If the permit is denied, the owner or Permittee would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;

iii. Issue a new permit under part 124 with appropriate conditions; or

iv. Take other actions authorized by these regulations.

d. State Continuation. An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement authority. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit.

3. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate

The Permittee must take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance

The Permittee must at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate Permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information

The Permittee must furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee must also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry

a. The Permittee must allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

b. Enter the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

c. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

d. Inspect at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

e. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location

10. Signatory Requirements

a. All reports required by this permit and other information requested by the Director must be signed as follows:

i. for a corporation—by a responsible corporate officer, such as a president, secretary treasurer, or vice president of the corporation in charge of principal business function, or any other person who performs similar policy or decision-making functions for the corporation;

ii. for partnership or sole proprietorship—by a general partner or the proprietor, respectively; or

iii. for municipality, state, federal, or other public agency—by either a principal executive or a ranking elected official.

b. A duly authorized representative of the official designated in paragraph (a) above may sign only if:

i. the authorization is made in writing by a person described in paragraph (a) above;

ii. the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and

iii. the written authorization is submitted to the Director.

c. If an authorization under paragraph (b) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (b) of this section must be submitted to the Director prior to or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph (b) of this section must make the following certification:

> *I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment.*

11. Reporting Requirements

Before written Authorization to Inject is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Part VII, D.10 of this permit and must be submitted to the EPA at the following address:

Underground Injection Control Section Chief, 8WD-SDU
1595 Wynkoop Street
Denver, CO 80202-1129

After written Authorization to Inject is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Part VII, D.10 of this permit and must be submitted to the EPA at the following address:

UIC Enforcement Coordinator, 8ENF-W-SD
1595 Wynkoop Street
Denver, CO 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

a. Planned changes. The Permittee must give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

b. Anticipated noncompliance. The Permittee must give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

c. Monitoring Reports. Monitoring results must be reported at the intervals specified in this Permit.

d. Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit must be submitted no later than 30 days following each schedule date.

e. Twenty-four hour reporting. The Permittee must report to the Director within 24 hours any noncompliance which may endanger human health or the environment, including:

   i. Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or
   ii. Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

   In addition, a follow up written report must be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission must contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

f. Information must be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting the Chief of the Water Enforcement Branch of the Enforcement and Compliance Assurance Division, or by contacting the EPA Region 8 Emergency Operations Center at (303) 293-1788.

g. The written report must also be provided to the Director in electronic format for release to the public and tribal governments on the EPA Region 8 UIC website.

i. Oil Spill and Chemical Release Reporting: The Permittee must comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center at **(800) 424-8802**.

j. Other Noncompliance. The Permittee must report all instances of noncompliance not reported under paragraphs Part VII, Section D.11.b, Section D.11.e or Section D.11.i at the time the monitoring reports are submitted. The reports must contain the information listed in Part VII, Section D.11.g and be provided to the Director in electronic format as required in Part VII, Section D.11.h.

k. Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee must promptly submit such facts or information to the Director.

PART VIII. FINANCIAL RESPONSIBILITY

A. Method of Providing Financial Responsibility

The permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§ 144.51(o), § 146.10, and § 146.92 of this chapter, and the permittee has submitted a plugging and abandonment report pursuant to 40 CFR § 144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

1. Types of Adequate Financial Responsibility

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

a. a surety bond with a standby trust agreement,
b. a letter of credit with a standby trust agreement,
c. a fully funded trust agreement, OR
d. a financial test and corporate guarantee.

A surety bond acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA (40 CFR § 144.70) and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

A fully funded trust agreement acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA. Annual reports from the financial institution managing the trust account must be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must demonstrate that the Permittee meets or exceeds certain financial ratios. The permittee must meet the EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the permittee does not meet the financial ratios, notice to the EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

A standby trust agreement acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account must be submitted to the Director showing the available account balance.

2. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, must submit 3 current independent plugging and abandonment cost estimates for the Director to accurately determine the likely cost to plug the well(s).

B. Insolvency

In the event of:

1. the bankruptcy of the trustee or issuing institution of the financial mechanism; or
2. suspension or revocation of the authority of the trustee institution to act as trustee; or
3. the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (1), (2), or (3) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), of the U.S. Code that names the owner or Permittee as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

C. Updated Cost Estimate and Timing for Demonstration of Financial Responsibility
An updated cost estimate and a demonstration of financial responsibility must be effective prior to issuance of the Final Permit.

D. This surety addresses a portion of the decommissioning activities cited in the U.S. Nuclear Regulatory Commission Materials License SUA-1600, pursuant to Title 10 Code of Federal Regulations Part 40, Appendix A, Criterion 9.

PART IX. COMPLIANCE WITH APPLICABLE FEDERAL LAWS

UIC regulation 40 CFR §144.4, requires the EPA to comply with the following Federal laws when they apply to the issuance of UIC permits. When any of these laws is applicable, its procedures must be followed. When the applicable law requires consideration or adoption of particular permit conditions or requires the denial of a permit, those requirements also must be followed.

A. The National Historic Preservation Act (NHPA) of 1966, 16 U.S.C. 470 et seq.
Section 106 of the NHPA and implementing regulations (36 CFR part 800) require the EPA, before issuing a permit, to adopt measures when feasible to mitigate potential adverse effects of the permitted activity and properties listed or eligible for listing in the National Register of Historic Places. The NHPA's requirements are to be implemented in cooperation with State Historic Preservation Officers and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation.

The Permittee must comply with the following mitigation measures:

1. The Permittee must abide by the stipulations of the Programmatic Agreement (PA) among U.S. Nuclear Regulatory Commission, U.S. Bureau of Land Managment, South Dakota State Historic Preservation Office, Powertech (USA), Inc. and Advisory Council on Historic Preservation Regarding the Dewey-Burdock In-Situ Recovery Project Located in Custer and Fall River Counties South Dakota (PA) dated March 19, 2014 and adopted by EPA on November 13, 2020.
2. When evaluated properties are NRHP-eligible, avoidance of the properties will be the preferred option. When avoidance is not possible and adverse effects will result, adverse effects will be resolved in accordance with Stipulation 5 of the PA: Resolution of Adverse Effects.
3. The Permittee will ensure employees and/or contractors involved in all phases of the Project are aware of and comply with the requirements of the PA. The Permittee may use measures such as initial orientation training, as well as pre-job briefings to inform employees and contractors of their responsibilities under the PA.
4. In the event a previously unknown cultural resource is discovered during the implementation of the Dewey-Burdock Project, all ground disturbance activities must halt within 150 feet of the area of discovery to avoid or minimize impacts until the property is evaluated for listing on the NRHP by qualified personnel. The Permittee must ensure the steps listed under Stipulation 9 of the PA are followed.

B. The Endangered Species Act, 16 U.S.C. 1531 et seq.

Section 7(a)(2) of the Act and implementing regulations (50 CFR part 402) require the EPA to ensure, in consultation with the Secretary of the Interior or Commerce, that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of the designated critical habitat of such species.

EPA incorporates the following measures in this UIC permit to avoid, minimize or mitigate any potential impacts to federally-listed species:

1. In the event that construction is planned during the whooping crane and rufa red knot migration seasons or the northern long-eared bat (NLEB) active season, within five days prior to the initiation of any construction activities, a qualified biologist must conduct pre-construction surveys for these species and training for workers to assist with the identification of all listed species during construction and operation.
   a. Whooping crane migration seasons: migrates through South Dakota April 1 to mid-May and mid-September to mid-November.
   b. Rufa red knot migration seasons: migrates through South Dakota mid-April to mid-May and mid-September to October 31.
   c. NLEB active season: mid-April to October 31. The critical pup season is June 1 – July 31.
2. If the whooping crane, the rufa red knot or the northern long-eared bat are sighted within one-half mile of the well sites or associated facilities during construction or operation, the Permittee must contact EPA and the FWS immediately and all construction work within one-half mile of the species' location must cease. Powertech will work with the FWS and a qualified biologist to minimize surface operation activities within one-half mile of the species' location. In coordination with the FWS, work may resume after the species leave the area. For this measure and other ESA-related matters related to this project, the Permittee should contact the FWS and EPA by phone, followed up by an e-mail. The contact points are:
   - The FWS South Dakota Field Office – (605) 224-8693, email: southdakotafieldoffice@fws.gov
   - EPA Region 8 UIC Program – (303) 312-6079, email: minter.douglas@epa.gov
3. Any wells, equipment or buildings associated with the UIC wells authorized under the permit with a fixed location within the project area must be constructed to eliminate openings that look like a small cave or hibernacle to avoid the entrance of any northern long-eared bats.
4. Spills or leaks of chemicals and other pollutants at the UIC well site must be reported to the appropriate regulatory agencies. The procedures of the surface management agency must be followed to contain leaks or spills.
5. If supplemental lighting is used during construction or operation activities, as a protection measure for northern long-eared bat, the lights must be directed and/or sheltered to minimize the amount of light escaping the work or project site.
6. The Permittee must install netting, use bird balls or other acceptable bird deterrent method to prevent birds and bats from accessing all project ponds.
7. Tree removal activities within the project area must be conducted outside of the northern long-eared bat active season (mid-April to October 31). This will minimize impacts to the northern long-eared bat, including to NLEB pups during the critical pup season.

8. During the northern long-eared bat active season (mid-April to October 31), the Permittee must use a motion-activated camera to monitor the Triangle Mine vertical ventilation shaft located at NWNW Section 35, T6S, R1E for 5 days and nights and determine if bats are entering and exiting. If no bats are observed entering or exiting the shaft, the Permittee must investigate the shaft to determine if bats are inside the shaft. If no bats are inside the shaft, the Permittee must cover the entrance to the shaft with finer mesh to prevent bats from entering. If bats are observed in the shaft, the Permittee must work with South Dakota Game, Fish and Parks to evaluate methods for establishing an appropriate buffer zone around the shaft to prevent tree removal or wellfield construction activity. The buffer zone will need to take into account the fact that the shaft is only a few feet away from a road that is used by local residents and may be improved to use as an access road to the Project Site.

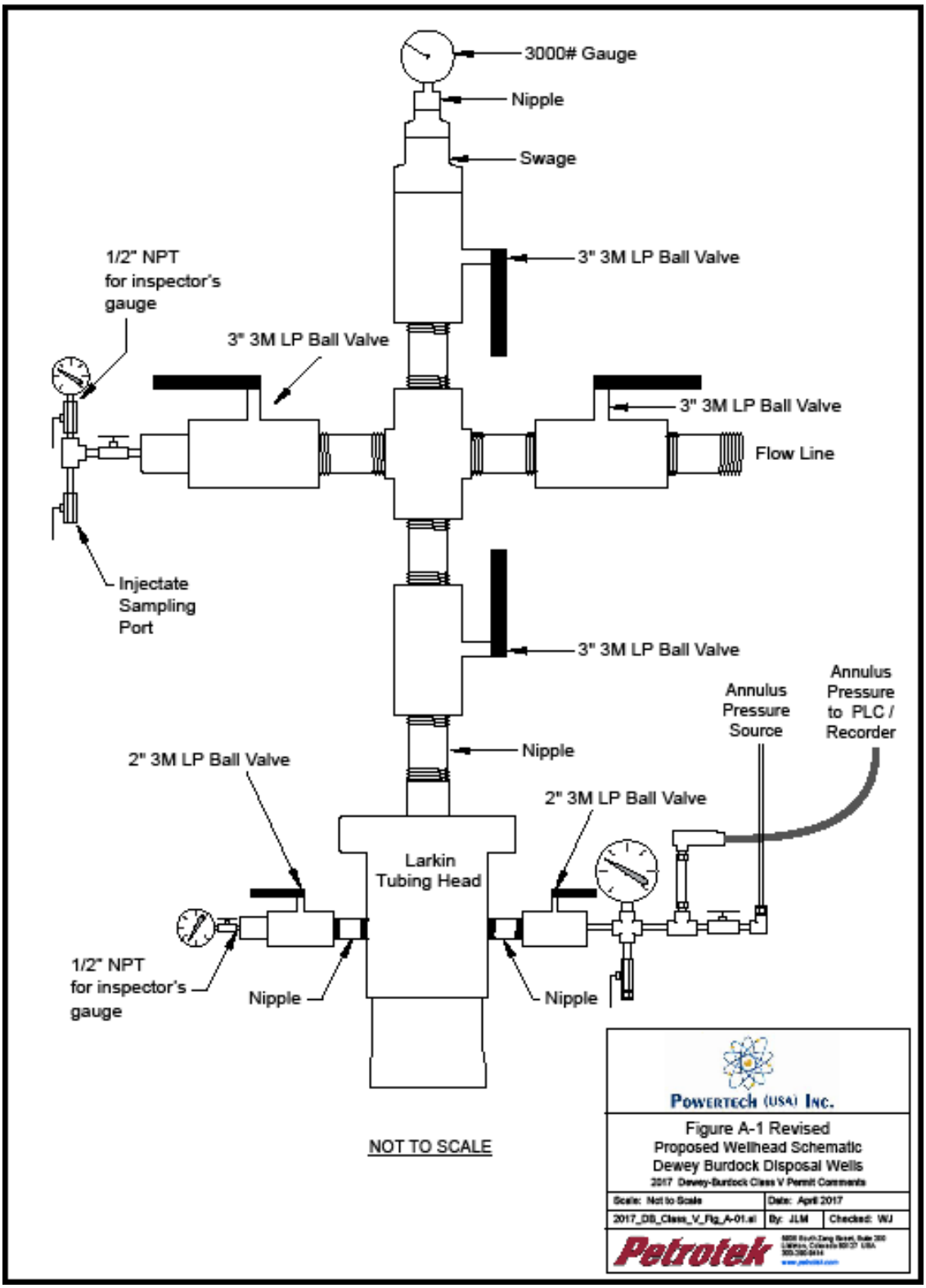
C. Record Keeping and Retention Requirements for Endangered Species Act Mitigation

The Permittee must document all activities related to compliance with Part IX, Section B of this Permit. All records of such documentation must be retained and made available for inspection or upon request by the Director. The Permittee must notify the Director as to the location where the records of ESA-related activities are maintained and notify the Director if this location changes. All records must be retained until all wells have been plugged and abandoned after which the owner or operator must deliver the records to the Director or obtain written approval from the Director to discard the records.

PART X. REFERENCES

Lee, John, 1982, Well Testing: Society of Petroleum Engineers of AIME: New York, 159 p.

Appendix A
Proposed Schematic Diagrams of the
Wellhead and Surface Facilities



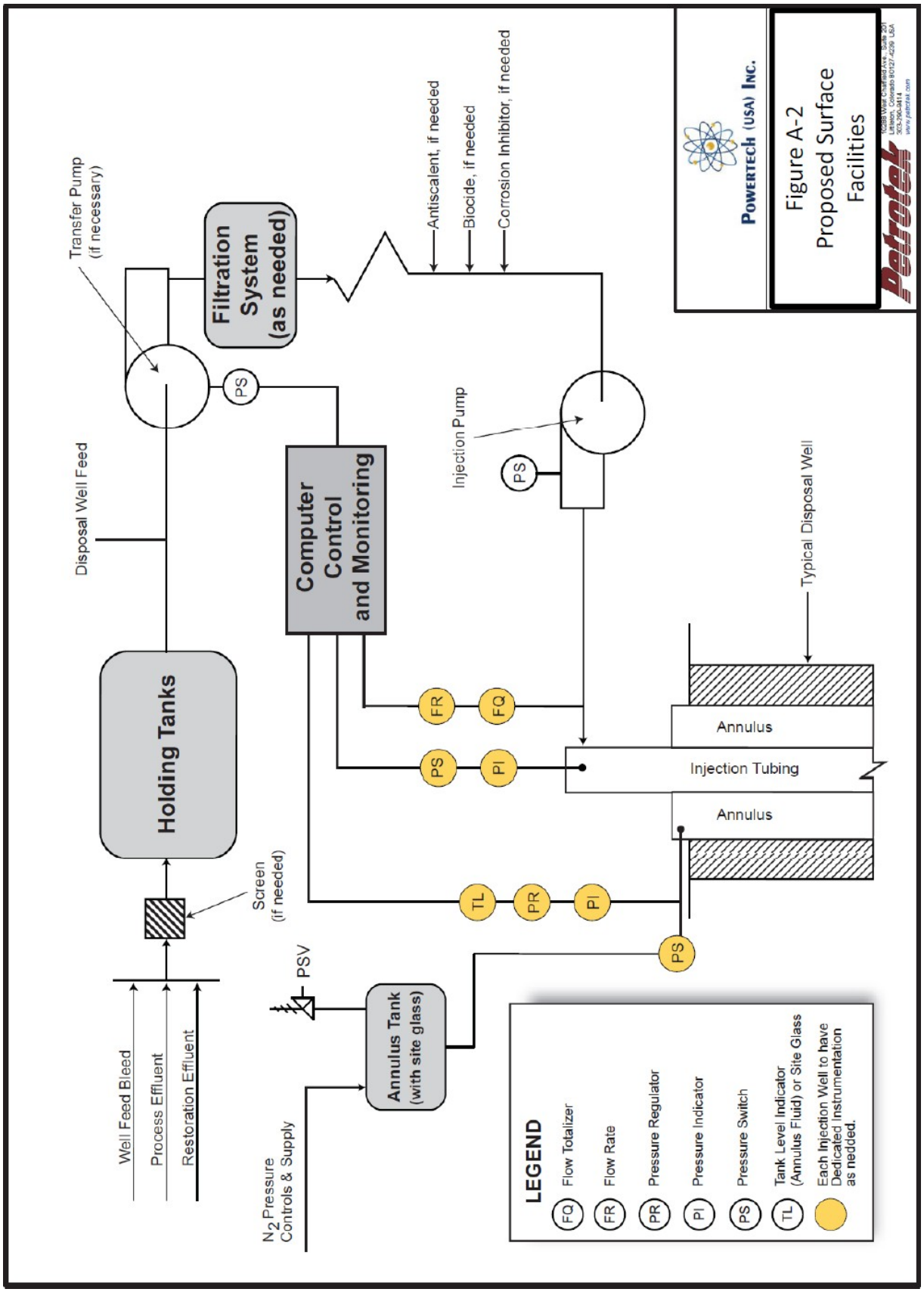


Figure A-2
Proposed Surface Facilities
POWERTECH (USA) INC.
Petrotek
Transfer Pump (if necessary)
Filtration System (as needed)
Antiscalent, if needed
Biocide, if needed
Corrosion Inhibitor, if needed
Disposal Well Feed
Computer Control and Monitoring
Injection Pump
Typical Disposal Well
Holding Tanks
Annulus
Injection Tubing
Annulus
Screen (if needed)
PSV
Annulus Tank (with site glass)
Well Feed Bleed
Process Effluent
Restoration Effluent
N2 Pressure Controls & Supply
LEGEND
FQ Flow Totalizer
FR Flow Rate
PR Pressure Regulator
PI Pressure Indicator
PS Pressure Switch
TL Tank Level Indicator (Annulus Fluid) or Site Glass
Each Injection Well to have Dedicated Instrumentation as needed.

UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

OGLALA SIOUX TRIBE,	)	
	)	
Petitioner,	)	No. 21-1167
	)	
v.	)	
	)	
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY	)	
	)	
	)	
Respondent.	)	
	)	

RULE 26.1 CERTIFICATE OF CORPORATE DISCLOSURE

Petitioner Oglala Sioux Tribe is a sovereign government. It has no parent corporations and issues no stock or shares. Black Hills Clean Water Alliance and NDN Collective are non-profit corporations with no parent corporations and issue no stock or shares.

Respectfully submitted,

/s/ Jeffrey C. Parsons
Jeffrey C. Parsons
Roger Flynn
Western Mining Action Project
P.O. Box 349
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Lyons, CO 80540
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stills@frontier.net
phone:(970)375-9231

Counsel for Petitioners

Filed this 12th day of November, 2025

CERTIFICATE OF SERVICE

I, Jeffrey C. Parsons, hereby certify that the foregoing was filed on November 12, 2025 through the Court's CM/ECF system, which will serve all registered counsel.

/s/ Jeffrey C. Parsons
Jeffrey C. Parsons