United States Nuclear Regulatory Commission Official Hearing Exhibit
In the Matter of: POWERTECH USA, INC.
(Dewey-Burdock In Situ Uranium Recovery Facility)
ASLBP #: 10-898-02-MLA-BD01
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Other:

POWERTECH (USA) INC.

9.0 ATTACHMENT J - STIMULATION PROGRAM

A stimulation program is not proposed for the Dewey-Burdock Project injection wells.

Well development (described in Section 11.4), which will include swabbing, will be used to improve well yield by enhancing hydraulic communication between the aquifer and the well.

10.0 ATTACHMENT K - INJECTION PROCEDURES

This attachment presents an overview of ISR operations, including injection procedures. It describes the general design of ISR well fields and specific design considerations for partially saturated conditions, historical mining operations, alluvium, and surface water features. It also discusses hydraulic well field control, groundwater restoration, lined retention ponds, and the project schedule.

10.1 Overview of Operations

The Dewey-Burdock Project will implement ISR methods for uranium extraction using a satellite facility and associated well fields within the Dewey portion of the project area and a CPP and associated well fields within the Burdock portion of the project area. The CPP will be used to produce the final uranium product (yellowcake or U_3O_8).

Uranium will be recovered by injecting lixiviant fortified with oxygen and carbon dioxide (barren lixiviant) into injection wells and recovering the resulting solution (pregnant lixiviant) from production wells. The uranium will be recovered from solution in IX vessels in the satellite facility or CPP. The CPP will include elution, precipitation, drying and packaging systems to recover the yellowcake.

Aquifer restoration will be completed following uranium recovery in each well field. During aquifer restoration, the groundwater in the well field will be restored in accordance with NRC requirements.

The vast majority of water withdrawn from the production wells will be reinjected as part of the ISR process, such that the net withdrawal rate will be only a small fraction of the gross pumping rate. A small portion of the production and restoration streams will not be reinjected to maintain an inward hydraulic gradient within each well field. This is referred to as the production or restoration bleed. The production and restoration bleed will be disposed using one of the two liquid waste disposal options.

The preferred liquid waste disposal option is underground injection of treated liquid waste in Class V deep disposal wells (DDWs). In this disposal option liquid waste will be treated to meet EPA non-hazardous waste requirements and injected into the Minnelusa and/or Deadwood Formations in four to eight DDWs being permitted pursuant to the Safe Drinking Water Act through the EPA UIC Program. It is anticipated that all liquid waste will be disposed using this option if sufficient capacity is available in DDWs.

The alternate liquid waste disposal option is land application. This option involves treatment in lined radium settling ponds followed by seasonal land application of treated liquid waste through

center pivot sprinklers. Land application would be carried out under a groundwater discharge plan, which is currently being permitted through DENR. Depending on the availability and capacity of DDWs, Powertech may use land application in conjunction with DDWs or by itself.

Ponds will be used in both liquid waste disposal options to treat the liquid waste, temporarily store liquid processing waste from the CPP, and temporarily store treated wastewater prior to disposal. Ponds will be designed and constructed in accordance with NRC license and DENR large scale mine permit requirements. Pond design information is found in Powertech (2011).

Solid wastes such as pond sludge; soils contaminated by spills or leaks; spills of loaded or spent IX resin; filter sand or other process media; and parts, equipment, debris (e.g., pipe fittings and hardware) and PPE that cannot be decontaminated for unrestricted release will be considered Atomic Energy Act-regulated wastes and will be disposed at an NRC or state-licensed facility in accordance with NRC license requirements.

Monitoring systems will be implemented to minimize potential impacts to the environment and public health. These include extensive groundwater monitoring, including establishing a perimeter monitor well ring around each well field and monitoring overlying and underlying water-bearing intervals to identify any unintended movement of ISR solutions. It also includes instrumentation and control systems to rapidly detect any potential pipeline leaks or spills.

A reclamation plan will be implemented in accordance with NRC license and DENR large scale mine permit conditions to restore groundwater, remove equipment, reclaim disturbed areas, and ensure that the project area meets all postmining land uses following ISR activities. See Section 15.3 for additional information.

10.2 Chemistry of Uranium ISR

The ISR process involves the oxidation and solubilization of uranium from its reduced state using a leaching solution (lixiviant). The lixiviant will consist of circulated groundwater with gaseous oxygen added to oxidize the solid-phase uranium to a soluble valence state and gaseous carbon dioxide added to form a complex with the soluble uranium ions so they remain in solution as they are transported through the ore body. As described in NRC guidance document NUREG-1569 (NRC, 2003), this lixiviant formulation will minimize potential groundwater quality impacts during uranium recovery and enable restoration goals to be achieved in a timely manner.

The chemistry of uranium oxidation and dissolution is described with the following equations:

Oxidation: $UO_2\ (\text{solid}) + \frac{1}{2}O_2\ (\text{in solution}) \rightarrow UO_3\ (\text{at solid surface})$

Dissolution: $UO_3 + 2\ HCO_3^- \rightarrow UO_2(CO_3)_2^{2-} + H_2O$

$UO_3 + CO_3^{2-} + 2HCO_3^- \rightarrow UO_2(CO_3)_3^{4-} + H_2O$

The principal uranyl carbonate ions formed as shown above are uranyl dicarbonate, $UO_2(CO_3)_2^{2-}$ [i.e., UDC], and uranyl tricarbonate, $UO_2(CO_3)_3^{4-}$ [i.e., UTC]. The relative abundance of each is a function of pH and total carbonate strength.

Once solubilized, the uranium-bearing groundwater will be pumped by submersible pumps in the well field production wells to the surface, where it will be ionically bonded onto IX resin. After the uranium is removed, the groundwater will be fortified with oxygen and carbon dioxide, recirculated and reinjected via the well field injection wells. When the IX resin is loaded with uranium, the loaded resin will be transferred to an elution (stripping) column, where the uranium will be eluted (stripped) from the resin using a saltwater solution. The resulting barren resin then will be recycled to recover more uranium. The saltwater eluate solution will be pumped to a precipitation process, where the uranium will be precipitated as a yellow, solid uranium oxide (yellowcake or U_3O_8). The precipitated uranium oxide then will be filtered, washed, dried and packaged in sealed containers for shipment for further processing to be used in the uranium fuel cycle.

10.3 Well Field Design

Each ISR well field will consist of a series of injection and production wells completed within the target mineralization zone. Prior to design and layout of the wells, the ore bodies will be delineated with exploration holes. These holes will be geologically and geophysically logged. Before drilling, each injection and production well will be assigned lateral coordinates, a ground surface elevation, depth to top of screened interval, and length of screened interval.

10.3.1 Injection and Production Wells

For all injection and production wells, the top of the screened interval will be at or below the base of the confining unit overlying the mineralized zone. The screened interval will be completed only across the targeted ore zone.

A typical (100 x 100 ft grid) well field layout is illustrated on Plate 10.1. This typical layout is based on the lateral distribution and grade of one of the uranium deposits within the project area.

The well patterns may differ from well field to well field, but a typical pattern will consist of five wells, with one well in the center and four wells surrounding it oriented in four corners of a square measuring between 50 and 150 feet on a side. Typically, a production well will be located in the center of the pattern, and the four corner wells will be injection wells. Figure 10.1 depicts a typical 5-spot well field pattern. The pattern dimensions will be modified as needed to fit the characteristics of each ore body. Other well field designs may be considered and evaluated in the well field hydrogeologic data packages.

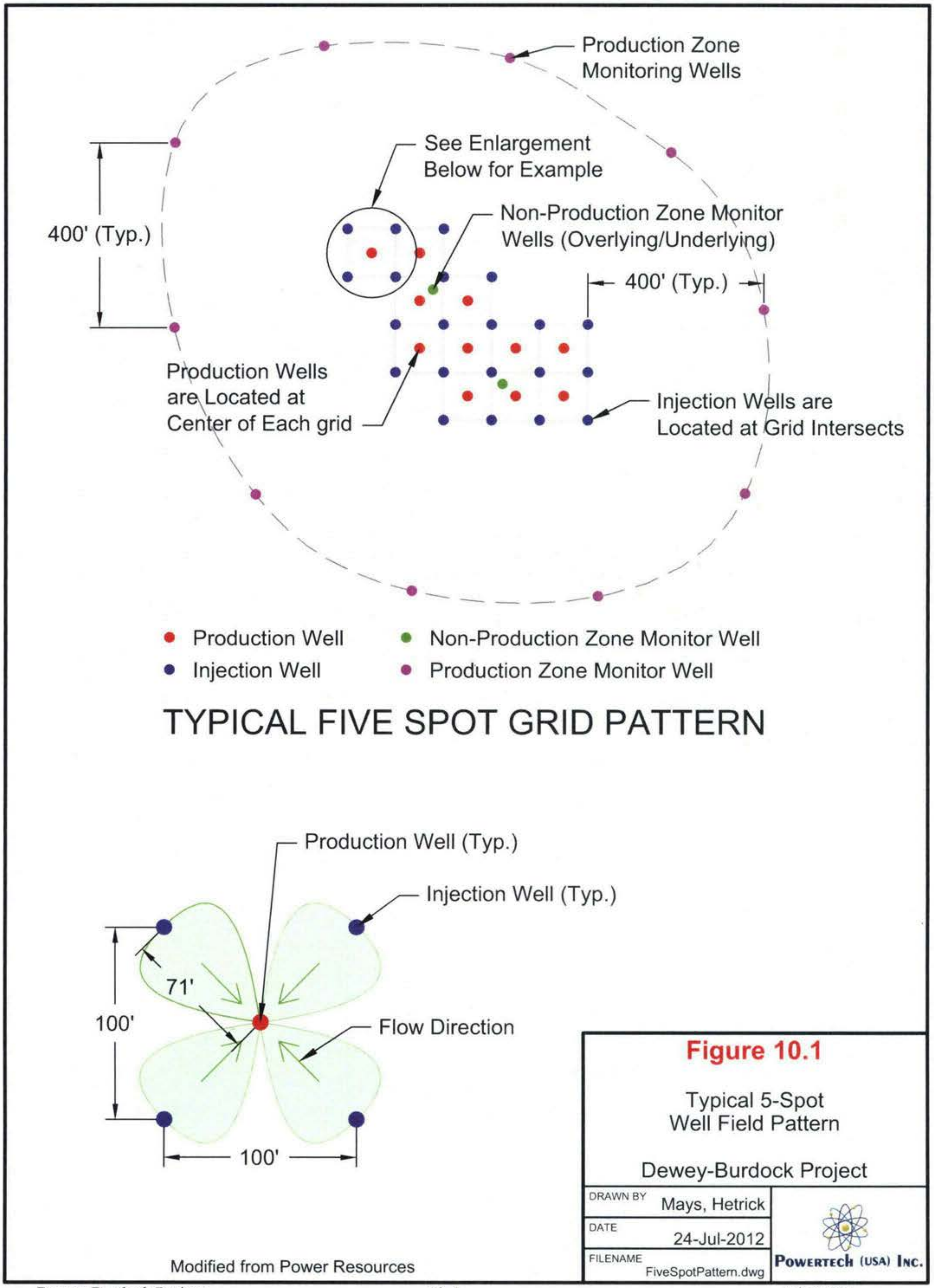


Figure 10.1

Typical 5-Spot
Well Field Pattern

Dewey-Burdock Project

All wells will be completed for use as either injection or production wells, so that flow patterns can be changed as needed to recover uranium and restore groundwater quality in the most efficient manner.

Figure 17.1 in Section 17 depicts the project ore bodies proposed for uranium recovery and shows all lower Fall River ore bodies in blue, all ore bodies within the upper Chilson Member of the Lakota Formation in green and middle/lower Chilson ore bodies in red. No well fields will be located within 1,600 feet of the project boundary in order to establish an operational buffer between the well fields and the project boundary. In addition, no well fields are proposed for partially saturated or unsaturated Fall River ore bodies in the eastern portion of the project area. All well fields and perimeter monitor wells will be located within the project boundary.

Production and injection wells will be connected to a header house, as shown on Plate 10.2. Well head connection details for injection and production wells are illustrated on Figures 11.2 and 11.3, respectively. Typically, one header house will service up to 20 production wells and 80 injection wells. Piping between the wells and header house will consist of high density polyethylene (HDPE) pipe with heat-welded joints, buried at least 5 feet below grade. The piping will be designed to withstand an operating pressure of 150 psig. The piping will terminate at the header house where it will be connected to manifolds equipped with control valves, flow meters, check valves, pressure sensors, oxygen and carbon dioxide feed systems (injection only), and programmable logic controllers. Electrical power to the header houses will be delivered via overhead power lines and via buried cable. Electrical power to individual wells will be delivered via buried cable from the header house.

As a well field expands, additional header houses will be constructed. They will be connected to one another via buried piping that is sized to accommodate the necessary injection and production flow rates and pressures. In turn, header pipes from entire well fields will be connected to either the satellite facility or CPP. A piping detail that shows the connection between the main header piping and laterals to header houses is shown on Plate 10.2.

10.3.2 Monitor Wells

Monitor wells will be installed in and around each well field to detect the potential migration of ISR solutions away from the target production zone. Perimeter monitor wells will be completed in the production zone around the perimeter of each well field. Non-production zone monitoring wells will be completed within each well field in the overlying and underlying aquifers. A detailed description of the monitor well design and sampling procedures is contained in Section 14 (Attachment P).

10.4 Hydraulic Well Field Control

Powertech will maintain hydraulic control of each well field from the first injection of lixiviant through the end of aquifer restoration. During uranium recovery, the groundwater removal rate in each well field will exceed the lixiviant injection rate, creating a cone of depression within each well field. During aquifer restoration, the groundwater removal rate in each well field will exceed the injection rate of permeate and clean makeup water from the Madison Limestone or another suitable formation. If there are any delays between uranium recovery and aquifer restoration, production wells will continue to be operated as needed to maintain water levels within the perimeter monitor rings below baseline water levels. This activity may be intermittent or continuous.

Verification of hydraulic control will be performed through water level measurements in perimeter monitor wells. Water levels will be measured using pressure transducers or manual electronic meters and recorded at a frequency appropriate to confirm hydraulic well field control as described in Section 14.2.3.

10.4.1 Flare Control

Flaring (movement of lixiviant outside of the well field pattern area) will be limited by maintaining hydraulically balanced well fields and adequate bleed during uranium recovery and aquifer restoration. The financial assurance calculations for aquifer restoration that are reviewed and approved by NRC will account for flare. Powertech has provided a flare estimate in the NRC license application that is justified by numerical groundwater modeling and is comparable to values that have been approved recently by NRC for other ISR facilities (Powertech, 2009b).

10.5 Approach to Well Field Development with Respect to Partially Saturated Conditions

Refer to Section 5.2.2.5 for a description of partially saturated conditions. The only instance where hydrologically unconfined (partially saturated) conditions exist within an area proposed for ISR operations occurs in the eastern portion of the project area. Powertech does not intend to conduct ISR operations in the Fall River sands in the eastern portion of the project area where the Fall River is partially saturated (i.e., hydraulically unconfined). Powertech is, however, proposing to conduct ISR operations in the underlying Chilson at these locations. The Chilson is physically and hydraulically isolated from the Fall River by the Fuson Shale. Although the Chilson is not fully saturated near the eastern edge of the project area, the mineralization occurs near the base of the formation. As a result, any ISR operations will occur within the portion of the Chilson where confining layers and sufficient head above the ore body will provide ample means to control ISR solutions.

Geologic Cross Section B-B' (Plate 6.14) shows the potentiometric surfaces as well as the interbedded shales and siltstones within the Fall River and Chilson. The cross section depicts the location of the mineralization in the Chilson in relation to the Chilson potentiometric surface. Near the eastern portion of the project area the potentiometric surface is nearly 100 feet higher than the mineralization. Locally occurring shale units may serve to further confine the mineralization within the Chilson. As such, Powertech does not anticipate that ISR operations will occur where there is less than 50 feet of potentiometric head over the ore body.

After license/permit issuance but prior to well field development, delineation drilling and well field pumping tests will be conducted to fully characterize the existing geologic and hydrogeologic conditions and to confirm sufficient head is available to perform normal ISR operations. As an integral component of the characterization activities, a detailed evaluation will be made, based on actual site conditions, regarding the application of ISR under partially saturated conditions should it be necessary. Partially saturated conditions, if encountered, would be similar in many respects to what has been licensed by NRC at other ISR projects (e.g., Moore Ranch in Wyoming) and would be addressed similarly with modeling.

10.6 Approach to Well Field Development with Respect to Historical Mine Workings

As described in Section 3.2 the former Darrow and Triangle open-pit mines and associated underground workings in the eastern portion of the project area extracted ore from the Fall River Formation. There are no underground mines within the project area that are not associated with, adjacent to, or extensions of the open pits, all of which are within the Upper Fall River Formation. These open-pit mines and underground workings did not penetrate the underlying Fuson Shale, which physically and hydraulically separates the Fall River from the underlying Chilson Member of the Lakota Formation across the entire project area.

Powertech will not conduct ISR operations in ore bodies in the Fall River in the vicinity of the Darrow and Triangle pits. Powertech proposes to conduct ISR operations within the Chilson in this area. Because of the physical and hydraulic separation of the Chilson from the overlying Fall River Formation, ISR operations in the Chilson will not affect the Fall River or create or enhance migration of constituents of concern from the surface (open-pit) or underground mines.

Figure 3.1 shows the spatial relationship between the potential ISR well fields and the historical mine areas. An examination of this figure shows that proposed Burdock Well Field 7 (B-WF7) underlies portions of the historical Darrow mine area. The targeted production zone for B-WF7 is the Lower Chilson. Figure 3.5 illustrates the stratigraphic separation of this Lower Chilson sand unit from the historical mining operations in sands of the Fall River Formation. The gamma activity shown within the Lower Chilson sand on the type log is representative of the proposed

uranium recovery horizon in B-WF7. This interval is over 200 feet below the base of the Fall River Formation and is separated by 40 feet of the Fuson Shale confining unit, as well as two interbedded shale intervals within the Chilson Member – one 12 feet thick and the other 23 feet thick.

As also shown on Figure 3.1, potential Burdock Well Field 8 (B-WF8) is below and horizontally adjacent to the surface expression of an area of past mining disturbance in Section 35, T6S, R1E. Excavation in this area was underway when the Edgemont mill was closed. This operation was on land owned by the Spencer family, and Donald Spencer (2011) related that all mining operations ceased before reaching the ore horizon. The pit was backfilled and reclaimed. Powertech's targeted uranium recovery horizon for B-WF8 is the Lower Chilson. This unit is at least 200 feet beneath the base of the Fuson Shale and is well below the historical mining disturbance in the Fall River Formation.

Powertech also will install and sample operational monitor wells in the Fall River, Chilson, and alluvium between the surface (open-pit) mines and well field areas. For additional information, refer to Section 14.

10.7 Approach to Well Field Development with Respect to Alluvium

This section summarizes Powertech's approach to well field development in areas of Beaver Creek and Pass Creek alluvium, including alluvial characterization, pump testing, and operational monitoring. This section consolidates information presented elsewhere in the application and includes references to the applicable sections.

Alluvial Characterization

Powertech completed an alluvial drilling program in 2011 to characterize the thickness, extents, and saturated thickness (if water was present) of the alluvium along Beaver Creek and Pass Creek. Alluvial characteristics will be further evaluated during well field delineation drilling described in Section 8.2.3.

Pump Testing

As described in Section 8.2.3, an extensive pump testing program will be designed and implemented prior to operation of each well field to evaluate the hydrogeology and assess the ability to operate the well field. Monitor wells will be completed in the alluvium, if present.

Operational Monitoring

Section 14.2 describes how alluvium will be treated as an overlying hydrogeologic unit and monitored appropriately during operational groundwater monitoring. Powertech also will

monitor potential changes in alluvial water quality throughout the project area through the monitoring network described in Section 14.3.

10.8 Groundwater Restoration

The plans for groundwater restoration are discussed below. Groundwater restoration in each well field will be conducted in accordance with NRC license requirements.

10.8.1 Target Restoration Goals

Groundwater restoration, or aquifer restoration, will be performed pursuant to NRC requirements to protect USDWs. The groundwater restoration program for all well fields will be conducted pursuant to 10 CFR Part 40, Appendix A, Criterion 5, which sets forth groundwater quality standards for uranium milling facilities. Currently, Criterion 5 states that groundwater quality at such facilities shall have primary goals of baseline (background) or an MCL, whichever is higher, or an alternate concentration limit (ACL). An ACL is a site-specific, constituent-specific, risk-based standard that demonstrates that maintaining groundwater quality at the requested level at a designated point of compliance (POC) will be adequately protective of human health and the environment at the point of exposure (POE) and that groundwater quality outside the boundary of the aquifer exemption approved by EPA will meet background (baseline) levels or MCLs. Satisfaction of prior class-of-use can be proposed as a factor in demonstrating justification for an ACL.

In the event that an ACL is requested, Powertech will be required by NRC license conditions to submit an ACL application to NRC staff in accordance with regulatory requirements under 10 CFR Part 40, Appendix A, Criterion 5(B)(5). Any ACL application will be in the form of a license amendment application that addresses, at a minimum, all of the relevant factors in 10 CFR Part 40, Appendix A, Criterion 5(B)(6), including but not limited to:

(a) Potential adverse effects on ground-water quality, considering:
- (i) The physical and chemical characteristics of the waste in the licensed site including its potential for migration;
- (ii) The hydrogeological characteristics of the facility and surrounding land;
- (iii) The quantity of ground water and the direction of ground-water flow;
- (iv) The proximity and withdrawal rates of ground-water users;
- (v) The current and future uses of ground water in the area;
- (vi) The existing quality of ground water, including other sources of contamination and their cumulative impact on the ground-water quality;
- (vii) The potential for health risks caused by human exposure to waste constituents;
- (viii) The potential damage to wildlife, crops, vegetation, and physical structures caused by exposure to waste constituents;
- (ix) The persistence and permanence of the potential adverse effects.

(b) Potential adverse effects on hydraulically-connected surface water quality, considering:
   (i) The volume and physical and chemical characteristics of the waste in the licensed site;
   (ii) The hydrogeological characteristics of the facility and surrounding land;
   (iii) The quantity and quality of ground water, and the direction of ground-water flow;
   (iv) The patterns of rainfall in the region;
   (v) The proximity of the licensed site to surface waters;
   (vi) The current and future uses of surface waters in the area and any water quality standards established for those surface waters;
   (vii) The existing quality of surface water including other sources of contamination and the cumulative impact on surface water quality;
   (viii) The potential for health risks caused by human exposure to waste constituents;
   (ix) The potential damage to wildlife, crops, vegetation, and physical structures caused by exposure to waste constituents; and
   (x) The persistence and permanence of the potential adverse effects.

Should it become necessary to submit an ACL application, Powertech will follow relevant NRC guidance and policy in effect at the time that an ACL would be requested.

Prior to operation, the baseline groundwater quality will be determined through the sampling and analysis of water quality indicator constituents in wells screened in the mineralized zone(s) across each well field. Section 14.4.1 describes the methods used to select baseline wells, sample the wells, and calculate baseline water quality statistics. The target restoration goals (TRGs) will be established as a function of the average baseline water quality and the variability in each parameter according to statistical methods approved by NRC.

10.8.2 Groundwater Restoration Process

Groundwater restoration will be conducted in accordance with NRC license requirements in a manner that will protect human health and the environment. The methods for achieving this objective are discussed in the following sections.

10.8.2.1 Groundwater Restoration Methods

During aquifer restoration, Powertech will restore groundwater quality consistent with the groundwater protection standards contained in 10 CFR Part 40, Appendix A, Criterion 5(B)(5), in accordance with NRC license requirements. The technology selected will depend on the liquid waste disposal option as described below. In the deep disposal well liquid waste disposal option, reverse osmosis (RO) treatment with permeate injection will be the primary restoration method. If land application is used to dispose liquid waste, then groundwater sweep with injection of clean makeup water from the Madison Limestone or another suitable formation will be used to restore the aquifer. In either case, aquifer restoration will be conducted in accordance with NRC

license requirements, which will establish the minimum number of pore volumes and the pore volume calculation method. Refer to Powertech (2011) for additional information.

10.8.2.1.1 Deep Disposal Well Option

In the deep disposal well liquid waste disposal option, the primary method of aquifer restoration will be RO treatment with permeate injection. In this method, water will be pumped from one or more well fields to the CPP or satellite facility for treatment. Treatment will begin with removal of uranium and other dissolved species in IX columns. The water will then pass through the restoration RO unit, which will remove over 90% of dissolved constituents using high pressure RO membranes. The treated effluent, or permeate, will be returned to the well field(s) for injection. The RO reject, or brine, will undergo radium removal in radium settling ponds and will then be disposed in one or more deep disposal wells.

The RO units will operate at a recovery rate of approximately 70%. Therefore, about 70% of the water that is withdrawn from the well fields and passed through the restoration RO unit will be recovered as nearly pure water, or permeate. In order to avoid excessive restoration bleed and consumptive use of Fall River and Chilson groundwater, permeate will be supplemented with clean makeup water from the Madison Limestone or another suitable formation. Permeate and makeup water will be reinjected into the well field(s) at an amount slightly less than the amount withdrawn from the well field(s). This will be done to maintain a slight restoration bleed, which will maintain hydraulic control of the well field(s) throughout active aquifer restoration. The restoration bleed typically will be 1% of the restoration flow rate unless groundwater sweep is used in conjunction with RO treatment with permeate injection, in which case the restoration bleed will average approximately 17%. Refer to the "Optional Groundwater Sweep" discussion in Section 10.8.2.1.3.

10.8.2.1.2 Land Application Option

In the land application liquid waste disposal option, the primary method of aquifer restoration will be groundwater sweep with Madison Limestone water injection. A groundwater discharge permit application through DENR was submitted in March 2012 for the land application option. This method will begin the same as the method described above for RO treatment with permeate injection; water will be pumped to the CPP or satellite facility for removal of uranium and other dissolved species in IX columns. The partially treated water will undergo radium removal in radium settling ponds and then will be disposed in the land application systems.

RO will not be used if there are no deep disposal wells available to accept the RO brine. Instead, clean makeup water from the Madison Limestone or another suitable formation will be injected into the well field(s) at a flow rate sufficient to maintain the restoration bleed. As before, the

restoration bleed will typically be 1% of the restoration flow rate unless the optional groundwater sweep method is used.

The water quality of the Madison Limestone is expected to be equal to or better than the baseline ore zone water quality, and injection of Madison Limestone water will therefore be similar to injection of permeate under the deep disposal well option.

10.8.2.1.3 Optional Groundwater Sweep

Although a 1% restoration bleed will be adequate to maintain hydraulic control of well fields undergoing active aquifer restoration, additional bleed may be required at times. For example, additional restoration bleed may be used to recover flare of ISR solutions outside of the well field pattern area. In addition to the restoration methods described above, Powertech may withdraw up to one pore volume of water through groundwater sweep over the course of aquifer restoration. This will result in an average restoration bleed of approximately 17%.

10.8.2.2 Effectiveness of Groundwater Restoration Techniques

This section describes how the groundwater restoration process that will be conducted in accordance with NRC license requirements is the same process that has been used successfully at other NRC and agreement state-licensed facilities. The preferred aquifer restoration method is RO treatment with permeate injection. This is the aquifer restoration method that will be used if deep disposal wells are used to dispose liquid waste. As described in Section 2.5.3 of NUREG-1910 (NRC, 2009), this method of aquifer restoration is responsible for returning "total dissolved solids, trace metal concentrations, and aquifer pH to baseline values." RO treatment with permeate injection has proven effective at achieving successful aquifer restoration as described in Uranium One (2008):

> Results of the effectiveness of groundwater sweep (or lack of it) were clearly demonstrated in the Christensen Ranch Wellfield Restoration report (CRWR) (COGEMA 2008[a]). Example plots from that report of mean well field water quality at the end of mining, groundwater sweep, RO and stabilization monitoring... indicate minimal improvement following groundwater sweep at MU3 and MU5 and an actual increase [in dissolved constituents] at MU6. Following application of RO, the TDS values at MU5 and MU6 decreased to levels below the target Restoration Goal. Uranium increased in MU5 and MU6 following groundwater sweep...and then was significantly lowered during RO. Approximately 1.8, 4.8 and 1.5 PVs of groundwater were removed from MU3, MU5 and MU6, respectively, during groundwater sweep. This water removal was totally consumptive by design, in that none of it was returned to the aquifer.
>
> Based on the results, minimal benefit, if any, was derived from [the groundwater sweep] phase of restoration. Eliminating groundwater sweep, an unnecessary,

ineffective and consumptive step in the restoration process, will reduce the number of PVs required to reach restoration goals.

Terminating RO once water quality has stabilized will minimize the consumptive use of groundwater and reduce the number of PVs of treatment.

10.8.3 Groundwater Restoration Monitoring

Refer to Section 14.4 for a discussion of groundwater restoration monitoring, including monitoring the progress of active restoration, excursion monitoring during groundwater restoration, and stability monitoring.

10.9 Stormwater Control and Mitigation

Powertech has evaluated flood inundation boundaries and will construct facilities outside of these boundaries to avoid potential impacts to facilities from flooding and potential impacts to Beaver Creek and Pass Creek in the event of any potential spills or leaks.

HEC-HMS models were used to calculate peak discharges, and HEC-RAS models were used to compute water-surface profiles and inundated areas during runoff events for Pass Creek, Beaver Creek and local small drainages.

Where possible, facilities will be located out of the 100-year flood inundation boundaries. Facilities which must be located within such boundaries will be protected from flood damage by the use of straw bales, collector ditches, and/or berms. If it is necessary to place a well head within the flood inundation boundary, diversions or erosion control structures will be constructed to divert flow and protect the well head. The well head also will be sealed to withstand brief periods of submergence. Pipelines will be buried below the frost line and will not be subject to flooding. Pipeline valve stations will be located outside of the 100-year flood inundation boundaries.

10.10 Schedule

Following the issuance of an NRC uranium recovery license, DENR large scale mine permit, EPA Class III UIC permit, and other relevant permits, it is anticipated that construction will commence on the first Burdock well field, CPP and ancillary facilities including storage ponds and land application pivots and/or deep disposal wells. It is anticipated that construction of the first Dewey well field and ancillary facilities will occur at the same time or follow shortly thereafter. Alternately, Powertech may develop either the Burdock or Dewey area well fields first, followed by the well fields in the other area. Uranium recovery operations within the permit area will continue for approximately 7 to 20 years during which additional well fields will be completed along the roll fronts at both the Dewey and Burdock portions of the permit area. Following operation of each well field, aquifer restoration will restore groundwater quality.

Following regulatory approval of successful aquifer restoration, each well field will be decommissioned. It is likely that the CPP will continue to operate for several years following decommissioning of the well fields. The CPP may continue to process uranium-loaded ion exchange resin from other ISR projects such as the nearby Powertech Aladdin and Dewey Terrace ISR projects planned in Wyoming, as well as possible tolling arrangements with other operators. The entire Dewey-Burdock Project will then be decommissioned and reclaimed in accordance with NRC, EPA, BLM and DENR requirements. The projected construction, operation, restoration and decommissioning schedule is provided in Figure 10.2.

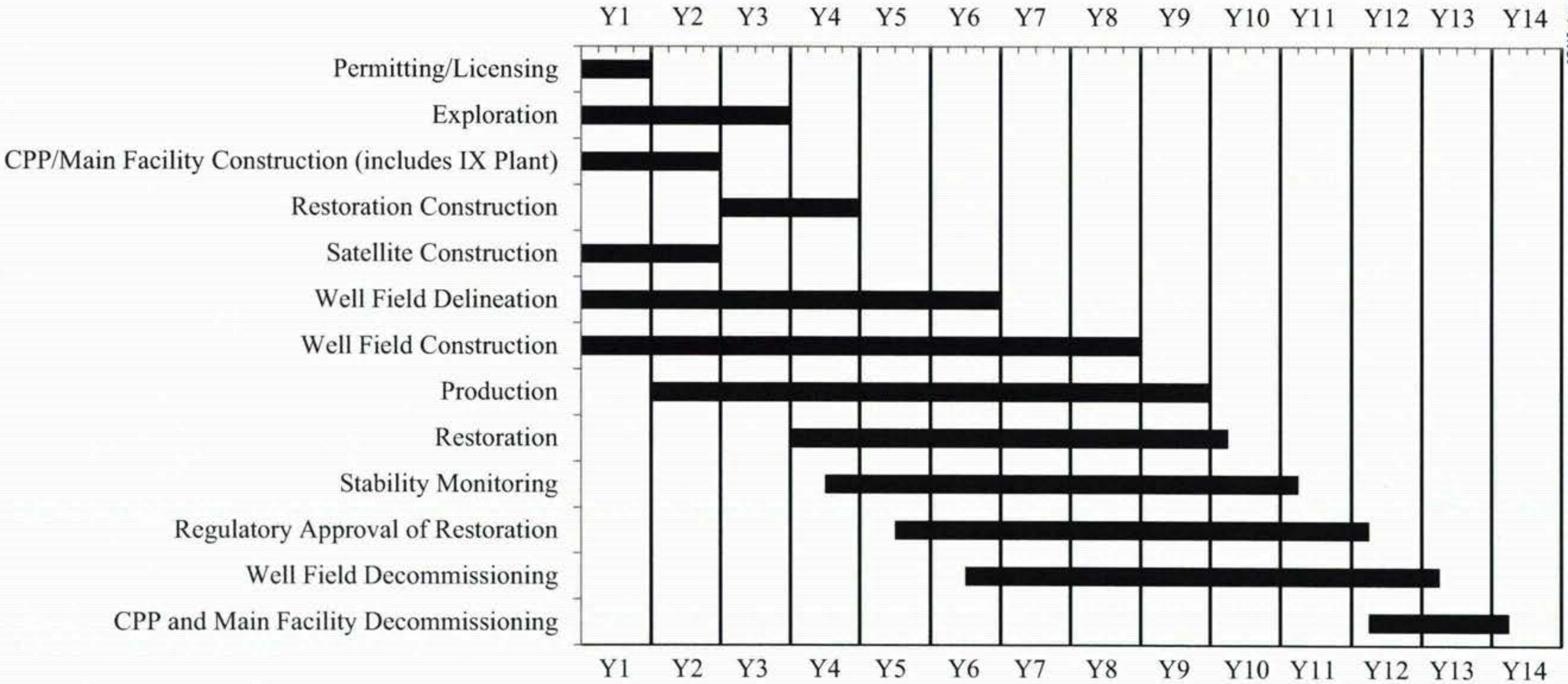


Figure 10.2: Projected Construction, Operation and Decommissioning Schedule

11.0 ATTACHMENT M - CONSTRUCTION DETAILS

This attachment details the construction procedures that will be utilized for injection, production and monitor wells at the Dewey-Burdock Project. All injection and production wells will be completed in accordance with South Dakota well construction standards and EPA standards for Class III UIC wells.

11.1 Well Construction Materials

Well casing material typically will be thermoplastic such as polyvinyl chloride (PVC) with at least SDR 17 wall thickness. The wells typically will be 4.5 to 6-inch nominal diameter and will meet or exceed the specifications of ASTM Standard F480 and NSF Standard 14. In order to provide an adequate annular seal, the drill hole diameter will be at least 2 inches larger than the outside diameter of the well casing.

The annulus will be pressure-grouted and sealed with neat cement grout composed of sulfate-resistant Portland cement in accordance with South Dakota wells construction standards. Water used to make the cement grout will not contain oil or other organic material. Cement grout could contain adequate bentonite to maintain the cement in suspension in accordance with Halliburton cement tables.

Casing will be joined using methods recommended by the casing manufacturer. PVC casing joints approximately 20 feet apart will be joined mechanically (with a watertight O-ring seal and a high strength nylon spline) to ensure watertight joints above the perforations or screens. Casings and annular material will be routinely inspected and maintained throughout the operating life of the wells.

11.1.1 Thermoplastic Well Casing Variance Request

Powertech requests a variance from the requirement in 40 CFR § 147.2104(b)(1) that plastic well casing materials, including PVC, ABS or others, not be used in new injection wells deeper than 500 feet in the State of South Dakota. This variance is requested on the following basis:

1. Collapse pressure calculations and well casing manufacturer specifications indicate that PVC well casing can be used at depths greater than 500 feet considering the site-specific well construction methods (see Section 11.1.1.1).
2. PVC well casing has been used successfully for wells deeper than 500 feet at uranium ISR facilities for many years (see Section 11.1.1.2).
3. PVC well casing is commonly used for other wells in South Dakota deeper than 500 feet (see Section 11.1.1.3).
4. Thermoplastic well casing is the preferred well casing material for ISR facilities due to corrosion resistance. The corrosion resistance of PVC compared to carbon steel well casing is well documented.

5. Each new injection, production and monitor well will be pressure tested to confirm the integrity of the casing prior to being used for ISR operations. MIT will be repeated every 5 years and after any repair where a downhole drill bit or under-reaming tool is used (see Section 11.5).
6. The injection pressure for each injection well will be maintained below the maximum pressure rating of the well casing (see Section 7.2).
7. An extensive excursion monitoring program will be implemented by installing and sampling monitor wells in the perimeter of the production zone and in overlying and underlying hydrogeologic units to detect potential excursions of ISR solutions into USDWs such as would occur with a leaking injection well (see Section 14.2).
8. Injection pressures will be monitored through automated control and data recording systems that will include alarms and automatic controls to detect and control a potential release such as would occur through an injection well casing failure (see Section 14.1).

The variance is requested pursuant to 40 CFR § 147.2104(d)(4), which states that the Regional Administrator may approve alternate casing provided that the owner or operator demonstrates that such practices will adequately protect USDWs.

11.1.1.1 Hydraulic Collapse Pressure Calculations

When specifying well casing and installation, Powertech will adhere to the requirements in ASTM F480, Standard Specifications for Thermoplastic Well Casing Pipe and Couplings Made in Standard Dimension Ratios (SDR), SCH 40 and SCH 80. ASTM F480 requires that "the depth at which thermoplastic well casing can be used is a design judgment." There is no depth of installation limit in ASTM F480 except that PVC well casing should be "used under conditions that meet manufacturer's recommendations for its type" and that "the driller shall install the thermoplastic casing in a manner that does not exceed the casing hydraulic collapse resistance." In accordance with these requirements, Powertech will ensure that all thermoplastic well casing meets the manufacturer's recommendations for its type and is installed in a manner that does not exceed the hydraulic collapse resistance.

The net hydrostatic pressure on the well casing is calculated as the difference between the exterior and interior hydrostatic pressure. The hydrostatic pressure is calculated as the fluid density multiplied by the fluid depth. Powertech will use cement to grout the annulus on all injection, production and monitor wells. Using a typical cement grout density of 90 lb/ft^3, and recognizing that the inside of the well casing will always be full of water before the cement cures (with a density of at least 62.4 lb/ft^3 depending on whether additives are used), the pressure versus depth gradient will be about 27.6 lb/ft^3 or about 0.2 psi/ft of depth. According to CertainTeed (2011), the hydraulic collapse pressure for SDR 17 PVC well casing is about 224 psi. Therefore, it would take an installation depth much greater than 1,000 ft to exceed this

pressure as long as cement grout were used and the well casing remains full until the cement hardens. Both of these conditions will be met in all injection, production and monitor well casing installations using the installation procedures described in Section 11.2. Water will be used to displace the cement and force it upward into the annulus; therefore, the well casing will always be full of water while the cement cures.

When designing and installing injection, production and monitor wells, Powertech will adhere to the requirements of ASTM F480 and manufacturer's criteria to ensure that the installation does not exceed the casing hydraulic collapse resistance.

11.1.1.2 Use of PVC Well Casing at Other ISR Facilities

There are numerous successful applications of PVC well casing at uranium ISR projects where the well depths are in excess of 500 feet. For example, at the Crow Butte project, where the average ore depth is 650 feet, 4.5-inch ID PVC well casing has been successfully used for many years (IAEA, 1994). There are also numerous Wyoming examples, including Irigaray/Christensen Ranch, where PVC well casing is routinely used at depths greater than 500 feet. According to COGEMA (2008b), SDR 17 PVC well casing is used for injection wells at Irigaray and Christensen, where the average depth of the ore zone in some mine units is between 500 and 600 feet.

11.1.1.3 South Dakota Well Construction Standards

South Dakota has tolled DENR administrative rules on UIC Class III wells and ISR until the department obtains primary enforcement authority. Therefore, South Dakota does not directly regulate well casing materials for injection, production and monitor wells. However, general South Dakota well construction standards in ARSD 74:02:04 allow the use of PVC well casing for other types of wells to depths greater than 500 feet. For example, Section 36 of ARSD 74:02:04 provides construction requirements for SCH 80 PVC private domestic and non-commercial livestock wells more than 1,000 feet deep.

ARSD 74:02:04, Sections 42 and 43 discuss general well casing requirements. Section 42 says, "Casing materials may be thermoplastic, steel, nonferrous metal, fiberglass, precast curbing, or concrete" but that, "Casing may only be used under conditions that meet manufacturer's recommendations and specifications for its type." Section 43 provides thermoplastic casing requirements, including that PVC well casing 5 inches or greater in diameter must have a minimum wall thickness of 0.250 inch. Powertech will ensure that all PVC well casing 5 inches or greater in diameter has a minimum wall thickness of 0.250 inch. This means that 5-inch PVC well casing will be SCH 40 or heavier or SDR 17 or heavier. Section 43 also requires

thermoplastic pipe to conform to ASTM F480. Compliance with the requirements in ASTM F480 is described in Section 11.1.1.1.

11.1.2 Compliance with 40 CFR § 147.2104(d)

The injection wells will comply with the following 40 CFR § 147.2104(d) regulations for protection of USDWs in South Dakota:

- (1)(i) Setting surface casing 50 feet below the lowermost USDW: The Fall River Formation and Chilson are the shallowest aquifers potentially classified as USDWs in the project area. Since the portion of the Fall River and Chilson within the well fields will be in an exempted aquifer and since injection wells will not target aquifers deeper than the Fall River or Chilson, there will not typically be any USDWs between the ground surface and the total injection well depth. Should saturated alluvium be present, surface casing will be installed through the alluvium regardless of whether it would be classified as a USDW.
- (1)(ii) Cementing surface casing by recirculating the cement to the surface from a point 50 feet below the lowermost USDW (see above); or
- (1)(iii) Isolating all USDWs by placing cement between the outermost casing and the well bore: The annular seal will be pressure grouted with neat cement grout as described above.
- (2) Isolate any injection zones by placing sufficient cement to fill the calculated space between the casing and the well bore to a point 250 feet above the injection zone: The entire annular seal will be pressure grouted with neat cement as described above.

In addition, Powertech will comply with the 40 CFR § 147.2104(d)(3) requirements for cement, including using cement (i) of sufficient quantity and quality to withstand the maximum operating pressure; (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 cement off a zone.

11.2 Well Construction Methods

Typical production and injection well installation will begin by drilling a pilot bore hole through the ore zone to obtain a measurement of the uranium grade and thickness. The ore depth is anticipated to range from 200 to 800 feet. Typical monitor well construction will begin with drilling a pilot bore hole through the target completion zone. For all wells, the pilot bore hole will be geologically and geophysically logged. After logging, the pilot bore hole will be reamed to the appropriate diameter to the top of the target completion zone. A continuous string of PVC casing will be placed into the reamed borehole. Casing centralizers will be installed as appropriate. With the casing in place a cement/bentonite grout will be pumped into the casing. The grout will circulate out the bottom of the casing and back up the casing annulus to the ground surface. The volume of grout necessary to cement the annulus will be calculated from the bore hole diameter of the casing with sufficient additional allowance to achieve grout

returning to surface. Grout remaining inside the well casing may be displaced by water or heavy drill mud to minimize the column of the grout plug remaining inside the casing. Care will be taken to assure that a grout plug remains inside the casing at completion. The casing and grout then will be allowed to set undisturbed for a minimum of 24 hours. When the grout has set, if the annular seal observed from the ground surface has settled below the ground surface, additional grout will be placed into the annular space to bring the grout seal to the ground surface.

After the 24-hour (minimum) setup period, a drill rig will be mobilized to finish well construction by drilling through the grout plug and through the target completion zone to the specified total well depth. The open borehole will then be underreamed to a larger diameter. Figure 11.1 depicts the typical well construction. Figures 11.2 and 11.3 depict the typical injection and production well heads, respectively. Figure 11.1 and the following discussion represent the anticipated typical injection well construction methods. The actual methods may vary.

A well screen assembly (if used) will be lowered through the casing into the open hole. The top of the well screen assembly will be positioned inside the well casing and centralized and sealed inside the casing using K packers. With the drill pipe attached to the well screen, a 1-inch diameter tremie pipe will be inserted through drill pipe and screen and through the sand trap check valves at the bottom of well screen assembly. Filter sand (if used), composed of well-rounded silica sand sized to optimize hydraulic communication between the target zone and well screen, then will be placed between the well screen and the formation. The volume of sand introduced will be calculated such that it fills the annular space. The sand will not extend upward beyond the K packers due to packer design. A well completion report then will be prepared for each well.

11.3 Geophysical Logging

Ore grade gamma log, self potential and single point resistivity electric logs will be run in the pilot holes prior to reaming the hole to final diameter to run casing. These logs will determine the location and grade of uranium and the sand and clay unit depths to properly plan each pattern.

11.4 Well Development

The primary goals of well development will be to allow formation water to enter the well screen, flush out drilling fluids, and remove the finer clays and silts to maximize flow from the formation through the well screen. This process is necessary to allow representative samples of groundwater to be collected, if applicable, and to ensure efficient injection and production operations. Wells will be developed immediately after construction using air lifting, swabbing, pumping or other accepted development techniques which will remove water and drilling fluids

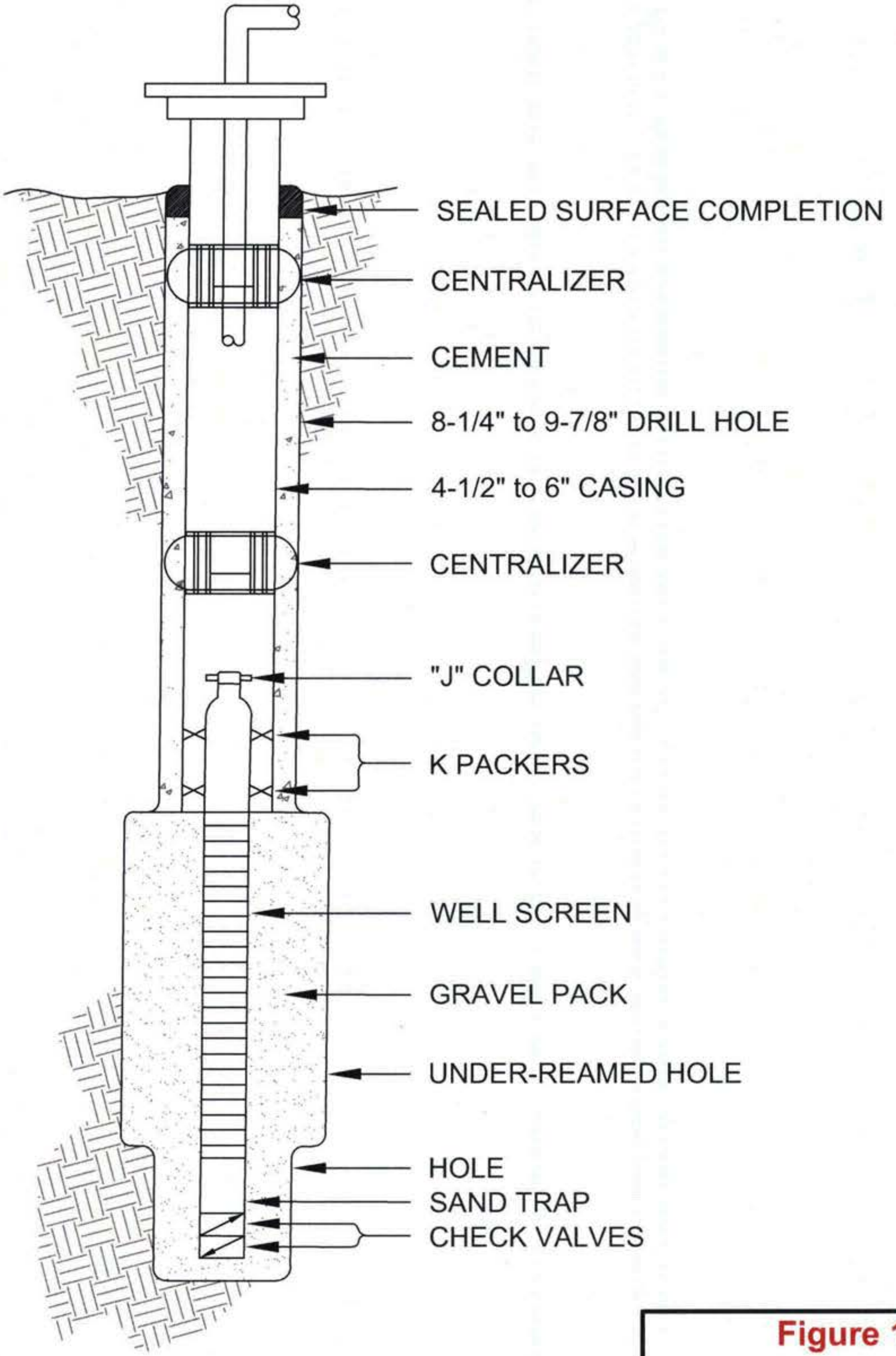


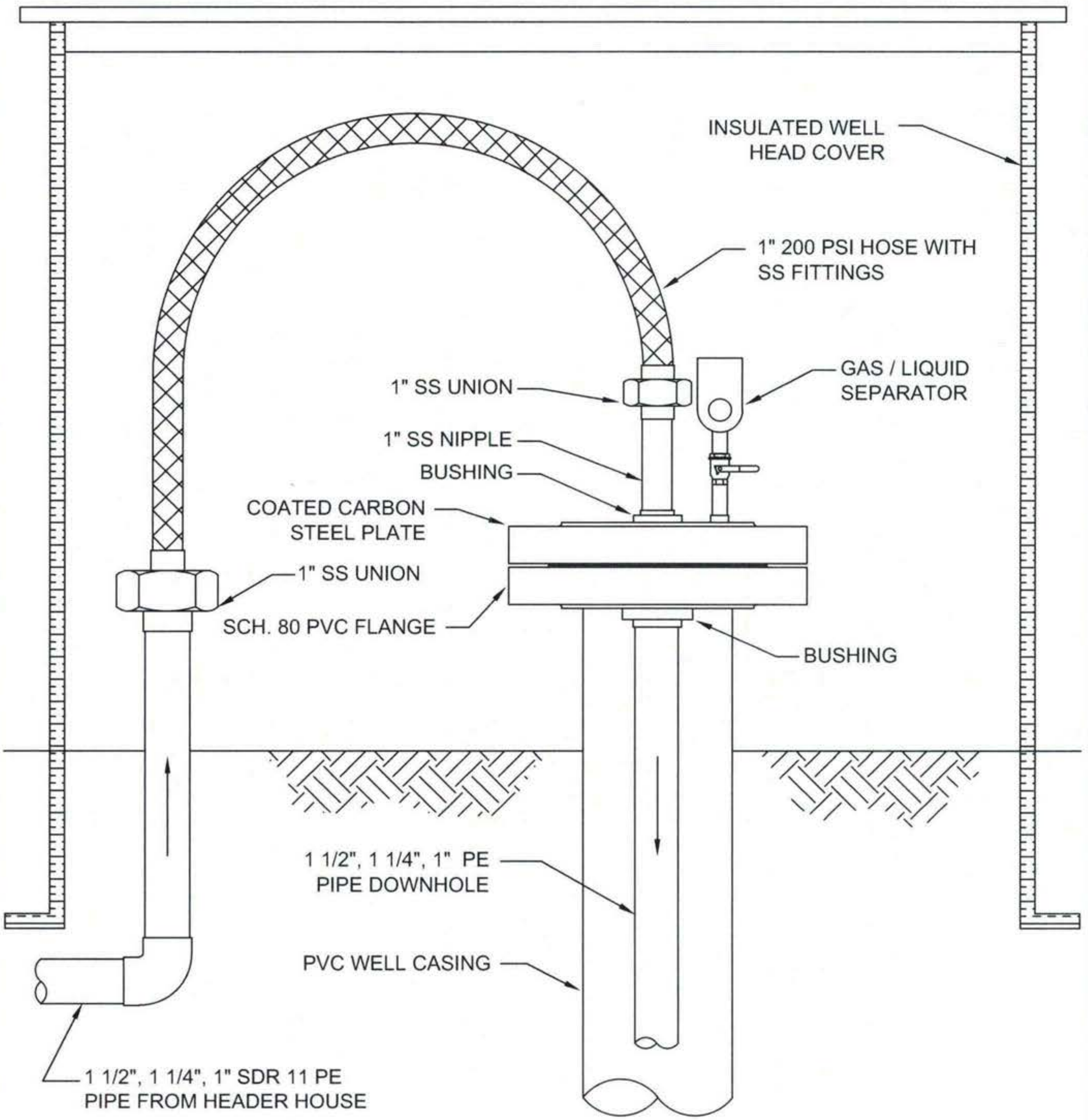
Figure 11.1

Typical Well Construction

Dewey-Burdock Project

DRAWN BY	L. Tafoya
DATE	24-Jul-2012
FILENAME	Wells-TypConstruction.dwg

POWERTECH (USA) INC.



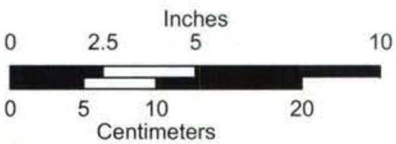


Figure 11.2

Typical Injection Wellhead

Dewey-Burdock Project

DRAWN BY	Cadd Svcs
DATE	24-Jul-2012
FILENAME	Wells-InjWellhead.dwg

POWERTECH (USA) INC.

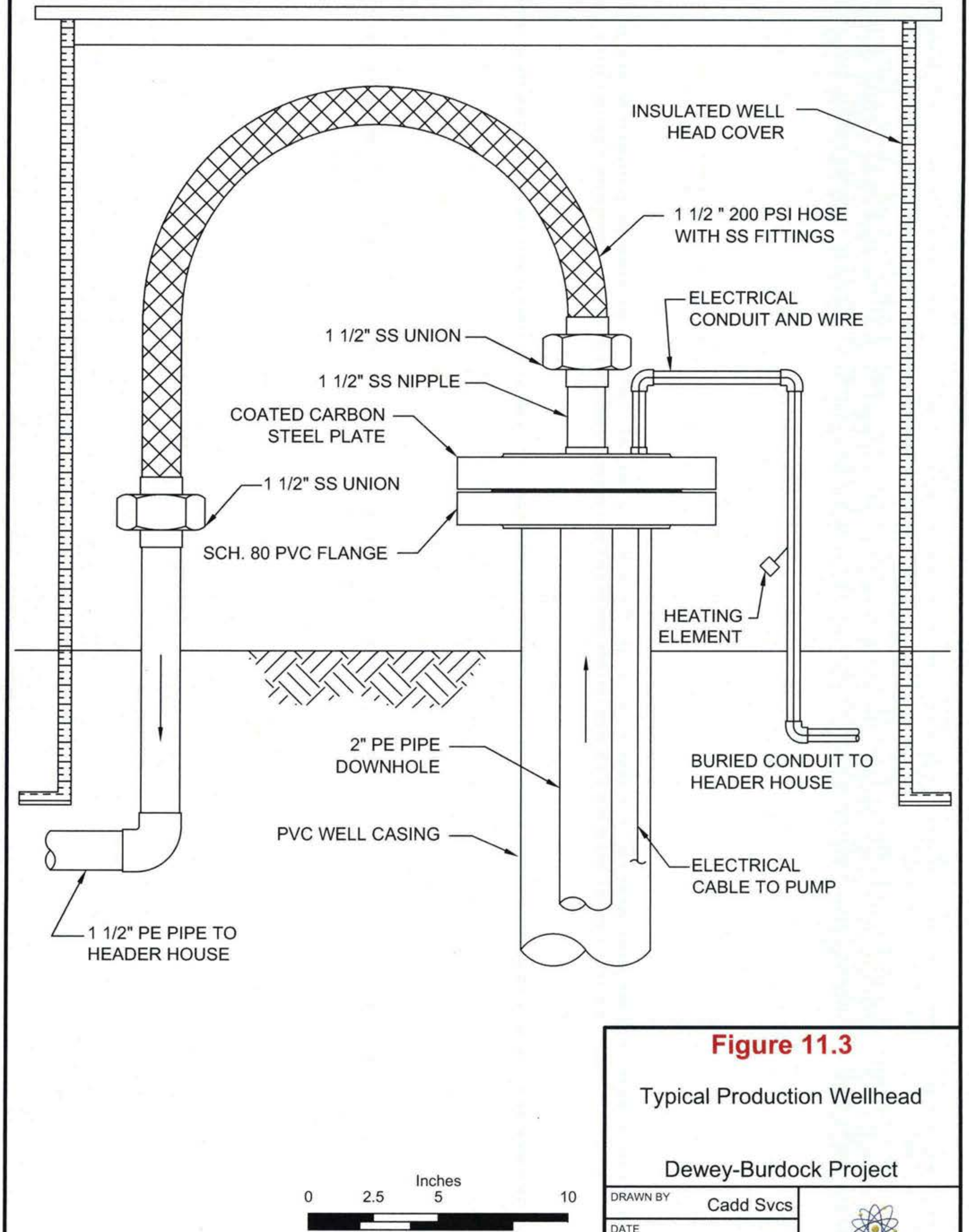


Figure 11.3

Typical Production Wellhead

Dewey-Burdock Project

DRAWN BY Cadd Svcs		POWERTECH (USA) INC.
DATE 24-Jul-2012		
FILENAME Wells-ProdWellhead.dwg		

from the casing and borehole walls along the screened interval. Prior to obtaining baseline samples from monitor wells, additional well development will be conducted to ensure that representative formation water is sampled. The water will be pumped sufficiently to show stabilization of pH and conductivity values prior to sampling to indicate that development activities have been effective.

11.5 Mechanical Integrity Testing

All injection, production, and monitor wells will be field tested to demonstrate the mechanical integrity of the well casing. The mechanical integrity testing (MIT) will be performed using pressure-packer tests. The bottom of the casing will be sealed with a plug, downhole inflatable packer, or other suitable device. The casing will be filled with water and the top of the casing will be sealed with a threaded cap, mechanical seal or downhole inflatable packer. The well casing then will be pressurized with water or air and monitored with a calibrated pressure gauge. Internal casing pressure will be increased to 125 percent of the maximum operating pressure of the well field, 125 percent of the maximum operating pressure rating of the well casing (which is always less than the maximum pressure rating of the pipe), or 90 percent of the formation fracture pressure (see Section 8.1), whichever is less. A well must maintain 90 percent of this pressure for a minimum of 10 minutes to pass the test.

If there are obvious leaks, or the pressure drops by more than 10 percent during the 10-minute period, the seals and fittings on the packer system will be checked and/or reset and another test will be conducted. If the pressure drops less than 10 percent the well casing will have demonstrated acceptable mechanical integrity.

11.5.1 Loss of Mechanical Integrity

If a well casing does not meet the MIT criteria, the well will be removed from service. The casing may be repaired and the well re-tested, or the well may be plugged and abandoned. Well plugging procedures are described in Section 15 (Attachment Q). EPA will be notified of any well that fails MIT following the reporting procedures described in Section 14.5. If a repaired well passes MIT, it will be employed in its intended service following demonstration that the well meets MIT criteria. If an acceptable test cannot be demonstrated following repairs, the well will be plugged and abandoned.

11.5.2 Subsequent Mechanical Integrity Testing

In addition to the initial testing after well construction, MIT will be conducted on any well following any repair where a downhole drill bit or under-reaming tool is used. Any well with evidence of subsurface damage will require new MIT prior to the well being returned to service. MIT also will be repeated once every 5 years for all active wells.

11.5.3 Reporting

MIT documentation will include the well designation, test date, test duration, beginning and ending pressures, and the signature of the individual responsible for conducting each test. MIT documentation will be available for inspection by the EPA. MIT results will be reported on a quarterly basis as described in Section 14.5 (Attachment P).

12.0 ATTACHMENT N - CHANGES IN INJECTED FLUID

This attachment details anticipated changes in pressure, native fluid displacement, and the direction of movement of injection fluid. It also describes how the chemical composition of the injected fluid will vary during the operational life of each well field.

Injection pressure will remain within the injection pressure limitations described in Section 7.2. Native fluid displacement and the direction of movement of injection fluid will be controlled through the production and restoration bleed, which will be used to maintain a cone of depression within each well field. If there are any delays between production and restoration, production wells will continue to be operated as needed to maintain the water levels within the perimeter monitor rings below baseline conditions. Within well field patterns, the direction of movement of injection fluid may be modified by reversing the function of some production and injection wells. Hydraulic well field control measures that include balancing each well field pattern and each well field and maintaining bleed from the onset of injection through active aquifer restoration will ensure that injection fluids are controlled.

The chemical composition of the injection fluid will vary during the operational life of each well field. Groundwater from well field(s) undergoing uranium recovery will be combined in the satellite facility or CPP and injected into the same well field(s) following uranium removal and oxygen and carbon dioxide addition. During the course of operating each well field, the dissolved constituent concentrations in the production zone and therefore in the injected fluid will increase due to ion exchange and the dissolution of soluble ions in the production zone. The chemical composition of the injection fluid is anticipate to increase from the baseline production zone groundwater quality (refer to Section 17.7 for the approximate baseline groundwater quality based on pre-operational monitoring completed to date) to levels at or below the maximum values shown in Table 7.2.

During aquifer restoration, permeate and/or clean makeup water from the Madison Limestone or another suitable formation will be injected into the well field(s). The chemical composition of the injection fluid during aquifer restoration is anticipated to be at or below the minimum values shown in Table 7.2.

13.0 ATTACHMENT O - PLANS FOR WELL FAILURES

This attachment outlines contingency plans to cope with system shut-ins or failures to prevent migration of fluids into any USDWs.

13.1 Introduction

The endangerment of USDWs may occur via any combination of at least six contamination pathways in which fluids can escape the injection zone and enter USDWs (EPA, 2002). These pathways include:

1) Migration of fluids through a faulty injection well casing;
2) Migration of fluids upward through the annulus located between the casing and the drilled hole;
3) Migration of fluids from an injection horizon through the confining zone (strata);
4) Vertical migration of fluids through improperly abandoned or completed wells;
5) Lateral migration of fluids from within an injection zone into a protected portion of that stratum (a portion that is defined as a USDW); and
6) Direct injection of fluids into or above a USDW.

The extent to which a USDW is threatened will depend on a number of factors including (EPA, 2002):

- The nature of the fluid being injected;
- The volume of the fluid being injected;
- The hydraulics of the flow system (pressure in the injection zone and overlying USDWs); and
- The amount of fluid that may enter the USDW via one or more of the pathways.

Proper construction and MIT of injection wells as outlined in Section 11 (Attachment M) and effective monitoring as described in Section 14 (Attachment P) will reduce the likelihood that any USDWs will be threatened.

13.2 Prevention Measures

13.2.1 Integrity Testing of Casing

Each new injection, production and monitor well will be pressure tested to confirm the integrity of the casing prior to being used for ISR operations. Mechanical integrity will be demonstrated after a well is constructed and before it is put into use. MIT procedures are discussed in

Section 11.5. Wells that fail MIT criteria will be repaired or plugged and abandoned and replaced as necessary.

13.2.2 Shutdown

13.2.2.1 General

All production, injection and monitor wells will be constructed of well casing that is cemented on the exterior to prevent vertical migration of ISR solutions up the annulus between the drill hole and the casing. Both production and injection wells will be piped into a collection header inside a header house.

Each production well will have a submersible pump associated with a circuit breaker in the header house that will be labeled with the corresponding well number (e.g., P-100). Each circuit breaker will have a start and stop switch that can be used to energize or de-energize the pump motor. The circuit breaker will be the main source of electrical power and will be used to de-energize and lock out the pump motor as necessary for repairs or maintenance.

Each injection well will have 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. There will be a manual flow control valve and a flow meter on each production and injection well to regulate the flow to and from each well and to balance the individual well patterns. The flow meters will be labeled with designated well identification numbers. The block valves will be closed for the appropriate injection or production well for shutdown and tag out.

13.2.2.2 Emergency Shutdown

Powertech will install automated control and data recording systems at the Dewey satellite facility and the Burdock CPP which will provide centralized monitoring and control of the process variables including the flows and pressures of production and injection streams. The systems will include alarms and automatic shutoffs to detect and control a potential release or spill.

Pressure and flow sensors will be installed, for the purpose of leak detection, on the main trunklines that connect the CPP and satellite facility to the well fields. In addition, the flow rate of each production and injection well will be measured automatically. Measurements will be collected and transmitted to both the CPP and satellite facility control systems. Should pressures or flows fluctuate outside of normal operating ranges, alarms will provide immediate warning to operators which will result in a timely response and appropriate corrective action.

Both external and internal shutdown controls will be installed at each header house to provide for operator safety and spill control. The external and internal shutdown controls are designed for automatic and remote shutdown of each header house. In the event of a 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 CPP and satellite facility control rooms.

An external header house shutdown will activate an electrical disconnect switch located on the outside of the header house or at the transformer pole which will shut down all electrical power to the header house. This will mitigate potential electrical hazards while de-energizing the header house and operating equipment. The production pumps will be de-energized which will result in flow stopping from all production wells. A control valve that will close when de-energized will be used on the injection header, which will stop the flow to all injection wells.

Internal shutdown controls will not involve de-energization of the header house but will result in the same alarm condition and shutdown of flow to all production and injection wells feeding the header house.

Each header house also will include a sump equipped with a water level sensor so that if a leak occurs, and the water level approaches a preset level, the sensor will cause an automatic shutdown of the header house. A pressure switch will be installed on each injection header to ensure that fluid pressure does not exceed the maximum designated pressure of the injection wells served by that header house (refer to Section 7.2). If the injection pressure reaches the maximum set value in the pressure switch, an automatic header house shutdown will occur.

13.3 Excursion Control

During production operations, lixiviant will be injected into the production zone through the injection wells, and recovery solution will be withdrawn by the submersible pumps in the production wells. During aquifer restoration, permeate and/or clean makeup water from the Madison Limestone or another suitable formation will be injected into injection wells and recovery solution pumped from the production wells. Recovering more groundwater than is injected during production and restoration will maintain a localized cone of depression for each well field. This induced gradient from the surrounding area toward the well field will serve as a control over the movement of ISR solutions and minimize the potential for lateral excursions.

Pre-operational excursion preventative measures will include, but will not be limited to:

1) Proper well construction and MIT of each well before use;

2) Monitor well design schema based upon delineation drilling to further characterize the zones of mineralization and to identify the target completion zones for all monitor wells; and

3) Pre-operational pumping tests with monitoring systems in place to obtain a detailed understanding of the local hydrogeology and to demonstrate the adequacy of the monitoring system.

Operational excursion preventative measures will include but will not be limited to:

1) Regular monitoring of flow and pressure on each production and injection well;

2) Regular flow balancing and adjustment of all production and injection flows appropriate for each production pattern;

3) Operation of bleed, and continuous measurement of bleed rate;

4) Monitoring of hydrostatic water levels in monitor wells to verify the cone of depression; and

5) Regular collection of samples from all monitor wells to determine the presence of any indicators of the migration of ISR solutions horizontally or vertically from the production zone.

Monitor wells will be positioned to detect any ISR solutions that may potentially migrate away from the production zone due to an imbalance in well field pressure. The monitoring well detection system described in Section 14 (Attachment P) is a proven method used at historically and currently operated facilities. Prior to injecting chemicals into each well field, pre-operational pump testing will be conducted to demonstrate hydraulic connection between the production and injection wells and all perimeter monitor wells (see Section 8.2.3). The results of the pump testing will be included within the hydrogeologic data packages and injection authorization data packages prepared for each well field as described in Sections 8.2.4 and 8.2.5. Additional monitor wells will be installed within overlying and underlying hydrogeologic units. The pre-operational pump testing also will demonstrate vertical confinement and hydraulic isolation between the production zone and overlying and underlying units. Sampling of monitor wells will occur according to the schedule described in Section 14.2 (Attachment P). The monitoring system and operational procedures have proven effective in early detection of potential excursions of ISR solutions for a number of reasons:

- Regular sampling for indicator parameters (such as chloride) that are highly mobile can detect ISR solutions at low levels well before an excursion is created.

- Monitoring hydrostatic water levels in perimeter monitor wells will provide immediate verification of the cone of depression, draw rapid attention in the event of a change, and provide the ability for measurement and implementation of corrective response.
- Bleed will create a cone of depression that will maintain an inward hydraulic gradient toward the well field area.
- The natural groundwater gradient and slow rate of natural groundwater flow is small relative to ISR activities and the induced gradient caused by the production and restoration bleed.

Controls for preventing migration of ISR solutions to overlying and underlying aquifers consist of:

- Regular monitoring of hydrostatic water levels and sampling for analysis of indicator species;
- Routine MIT of all wells on a regular basis (at least every 5 years) to reduce any possibility of casing leakage;
- Completion of MIT on all wells before putting them into service or after work which involves drilling equipment inside of the casing;
- Proper plugging and abandonment of all wells which do not pass MIT or that become unnecessary for use;
- Proper plugging and abandonment of exploration holes with potential to impact ISR operations; and
- Sampling monitor wells located within the overlying and underlying hydrogeologic units on a frequent schedule.

These controls work together to prevent and detect ISR solution migration. Plugging any exploration holes that pose the potential to impact the control and containment of ISR solutions prevents connection of the production zone to overlying and underlying units. The EPA UIC requirements for MIT assure proper well construction, which is the first line of defense for maintaining appropriate pressure without leakage. Sampling the monitor wells will enable early detection of any ISR solutions should an excursion occur. Additional preventative measures are described in Section 14 - Monitoring Program (Attachment P).

13.3.1 Excursion Corrective Action

Powertech will implement the following corrective action plan for excursions occurring during production or restoration operations. Corrective actions to correct and retrieve an excursion will include but will not be limited to:

- Adjusting the flow rates of the production and injection wells to increase the aquifer bleed in the area of the excursion;

- Terminating injection into the portion of the well field affected by the excursion;
- Installing pumps in injection wells in the portion of the well field affected by the excursion to retrieve ISR solutions;
- Replacing injection or production wells; and
- Installing new pumping wells adjacent to the well on excursion status to recover ISR solutions.

In the event of an excursion, the sampling frequency will be increased to weekly. The NRC will be notified within 24 hours by telephone or email and within 7 days in writing from the time an excursion is verified. In addition, if the excursion has potential to affect a USDW, EPA will be notified verbally within 24 hours and in writing within 5 days. A written report describing the excursion event, corrective actions taken and the corrective action results will be submitted to all involved regulatory agencies within 60 days of the excursion confirmation.

If 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, corrective actions taken, and results obtained. If an excursion is not corrected within 60 days of confirmation, Powertech will terminate injection into the affected portion of the well field until the excursion is retrieved, or provide an increase to the reclamation financial assurance obligation in an amount that is agreeable to NRC and that would cover the expected full cost of correcting and cleaning up the excursion. The financial assurance increase will remain in force until the excursion is corrected. The written 60-day excursion report will state and justify which course of action will be followed. If wells are still on excursion status at the time the 60-day report is submitted to NRC, and the financial assurance option is chosen, the well field restoration financial assurance obligation will be adjusted upward. When the excursion is corrected, the additional financial assurance obligations resulting from the excursion will be removed.

13.3.2 Potential Impacts from Excursions

By properly designing, pump testing, and operating each well field and its associated monitor well network, including specifically addressing those areas having the greatest potential for excursions, Powertech will minimize the risk of excursions and the potential impacts resulting from excursions. By routinely sampling monitor wells for changes in water level and concentrations of the highly mobile and conservative excursion parameters of chloride, total alkalinity and conductivity, Powertech will ensure that any potential excursions are identified and corrected quickly. As described by NUREG-1910, Supplement 1 (NRC, 2010), "An excursion is defined as an event where a monitoring well in overlying, underlying, or perimeter well ring detects an increase in specific water quality indicators, usually chloride, alkalinity and conductivity, which may signal that fluids are moving out from the wellfield … The perimeter

monitoring wells are located in a buffer region surrounding the wellfield within the exempted portion of the aquifer. These wells are specifically located in this buffer zone to detect and correct an excursion before it reaches a USDW ... To date, no excursion from an NRC-licensed ISR facility has contaminated a USDW."

13.4 Well Casing Failure

Injection well casing failure is unlikely to occur due to accepted and proven well completion techniques, MIT prior to operations and at least every 5 years, and routine monitoring of the injection pressure for each well. Should an injection well casing failure occur, the well will be removed from service and examined to verify the condition of the casing. If possible, MIT will be conducted. Resistivity or video logs may be used to identifying the location of the well casing failure. Following identification of a defective well casing, the well will be repaired or plugged and abandoned as described in Section 15 - Plugging and Abandonment Plan (Attachment Q). MIT will be conducted prior to use and after any repair that involves entering a well with a cutting tool such as a drill bit or under-reamer.

The monitoring program described in Section 14 - Monitoring Program (Attachment P) will be used to rapidly detect any excursions in the event of a well casing failure. The corrective action plan described in Section 13.3.1 will be used to minimize potential impacts from excursions and protect USDWs.

13.5 Mitigation Measures for Other Potential Environmental Impacts

This section briefly summarizes the mitigation measures for other potential environmental impacts resulting from the Dewey-Burdock Project. Additional information is found in the NRC license application (Powertech, 2009a) and the responses to the Technical Report requests for additional information submitted to NRC in June 2011 (Powertech, 2011).

13.5.1 Spills and Leaks

Well field features such as header houses, well heads or pipelines could contribute to pollution in the unlikely event of a release of ISR solution due to pipeline or well failure. Potential impacts will be minimized by routine MIT of all injection, production and monitor wells and hydrostatic leak testing of all pipelines during construction; implementing an instrumentation and control system to monitor pressure and flow and immediately detect and correct an anomalous condition; and implementing a spill response and cleanup program in accordance with NRC license requirements and DENR permit conditions.

13.5.2 *Potential Natural Disaster Risk*

NRC guidance in NUREG/CR-6733 (NRC, 2001) evaluates potential risks associated with ISR facilities for the release of radioactive materials or hazardous chemicals due to the effects of an earthquake or tornado strike. The NRC determined that in the event of a tornado strike, chemical storage tanks could fail resulting in the release of chemicals. This risk will be minimized by implementing secondary containment measures for chemical storage. NUREG/CR-6733 concluded that the risk of a tornado strike on an ISR facility is very low and that no design or operational changes are necessary to mitigate the potential risks, but that it is important to locate chemical storage tanks far enough from each other to prevent contact of reactive chemicals in the event of an accident. Chemical storage tanks will be separated at the Dewey-Burdock Project.

Considering the relative remoteness of the project area, the potential consequences of a tornado strike would be considerably less than if the facilities were in a more populated area. Nevertheless, there are risks to workers that will be addressed. Powertech will prepare and have available onsite for regulatory inspection an Emergency Response Plan that will contain emergency procedures to be followed in the event of severe weather or other emergencies. Included in the plan will be procedures for notification of personnel, evacuation procedures, damage inspection and reporting. It also will address cleanup and mitigation of spills that may result from severe weather.

The NRC determined that the radiological consequences of materials released and dispersed due to earthquake damage at an ISR facility were no greater than for a tornado strike. NUREG-0706 (NRC, 1980a) determined that mitigation of earthquake damage could be attained following adequate design criteria. NUREG/CR-6733 concluded that risk from earthquakes is very low at uranium ISR facilities and that no design or operational changes are required to mitigate the risk, but that it is important to locate chemical storage tanks far enough from each other to prevent contact of reactive chemicals in the event of an accident.

All buildings, structures, foundations, and equipment will be designed in accordance with recommendations in the latest versions of the International Building Code and ASCE-7 published by the American Society of Civil Engineers. Maps published in ASCE-7, and the latest version of the USGS Earthquake Ground Motion Tool, along with information regarding soil characteristics provided by the project professional geotechnical engineer, will be used to determine seismic loadings and design requirements.

13.5.3 *Potential Fire and Explosion Risk*

Powertech has addressed the risk of fire and explosions in the Technical Report request for additional information responses (Powertech, 2011). The design criteria for chemical storage and

feeding systems include applicable sections of the International Building Code, International Fire Code, OSHA regulations, RCRA regulations, and Homeland Security regulations. Additional measures for preventing fires and explosions within processing facilities include items such as designing facilities and chemical storage areas to minimize risk of exposure in the event of an accident and developing emergency response procedures. In order to protect facilities from wildfires, vegetation will be controlled around processing facilities, header houses, and well fields. In the event of an approaching wildfire, operators will be trained to shut down well field operations and, if necessary, to evacuate facilities until the danger to personnel has passed. Damage, if any, will be assessed and remediated prior to re-starting operations.

Powertech will maintain firefighting equipment on site and will provide training for local emergency response personnel in the specific hazards present in the project area.

13.5.4 Potential Power Outage

Loss of power to the project site will cause production wells to stop operating, resulting in shutdown of all production and injection flows. This condition avoids flow imbalance within the well fields, but a well field bleed would not be maintained during the power failure. The time span for the aquifer to recover from operational drawdown back to its natural groundwater gradient is much longer than the duration of a typical power outage. Since ISR solutions would not begin to travel to the monitoring ring until the cone of depression caused by the bleed had recovered and groundwater had returned to its natural gradient, excursions are very unlikely within the short time period of a typical power outage.

Power outages in the project area would not be likely to last more than a few days or weeks under most conceivable scenarios. Powertech will use generators onsite and may also contract for temporary generators to operate well field pumps sufficiently to maintain a cone of depression within the well field if unforeseen power outages occur with expected duration of more than a few weeks. Backup generators will be installed to maintain continuous instrumentation monitoring and alarms in the CPP, satellite facility, and well fields. Backup power also will be provided for lights and emergency exits.

14.0 ATTACHMENT P - MONITORING PROGRAM

This attachment describes the monitoring programs directly related to the proposed Class III UIC permit, including monitoring the pressure, flow rate and chemical characteristics of the injection fluid. It also describes monitoring programs that will be conducted in accordance with NRC license requirements designed to protect groundwater quality outside of the exempted aquifer. These programs include excursion monitoring and monitoring domestic, stock, and other wells in the vicinity of the ISR well fields.

14.1 Injection Fluid Monitoring

Powertech will install automated control and data recording systems at the Dewey satellite facility and the Burdock CPP which will provide centralized monitoring and control of the process variables including the flow rate and pressure of the injection stream in each header house. In addition, the flow rate of each injection well will be automatically measured. Pressure gauges installed at each injection wellhead or in the injection manifold also will be manually recorded at least daily.

The volumetric flow rate of oxygen and carbon dioxide will be measured at the point of injection into the barren lixiviant using calibrated gas flow meters. The flow meters will be routinely calibrated according to manufacturer recommendations.

The injection fluid in each operating well field will be sampled monthly. Samples will be collected from the injection manifold, individual injection flow lines, or the injection wellheads following the appropriate quality assurance/quality control (QA/QC) procedures (refer to Section 14.7). Samples will be submitted to an EPA-certified laboratory and analysed for the parameters in Table 14.1.

14.2 Excursion Monitoring

Following is a brief summary of the excursion monitoring program that will be conducted in accordance with NRC license requirements to detect potential horizontal or vertical excursions of ISR solutions. Additional details regarding the excursion monitoring program can be found in Powertech (2011).

14.2.1 Monitoring Network Design

Monitor wells will be installed in and around each well field to detect the potential migration of ISR solutions away from the production zone. Perimeter monitor wells will be completed in the ore zone around the perimeter of each well field. Non-production zone monitoring wells will be completed within each well field in the overlying and underlying hydrogeologic units.

Table 14.1: Injection Fluid Characterization Parameters

Test Analyte/Parameter	Units	Method
Physical Properties		
pH	pH Units	A4500-H B
Total Dissolved Solids (TDS)	mg/L	A2540 C
Conductivity	μmhos/cm	A2510 B
Common 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
Metals - Dissolved		
Arsenic, As	mg/L	E200.8
Iron, Fe	mg/L	E200.7
Lead, Pb	mg/L	E200.8
Manganese, Mn	mg/L	E200.8
Strontium, Sr	mg/L	E200.8
Uranium, U	mg/L	E200.7, E200.8
Vanadium, V	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

14.2.1.1 Perimeter Monitor Wells

Perimeter monitor wells will be positioned around the perimeter of each well field as illustrated on Plate 10.1 and Figure 10.1. The perimeter monitor well "ring" serves two purposes: 1) to monitor any horizontal migration of fluid outside of the production zone, and 2) to determine baseline water quality data and characterize the area outside the production pattern area.

Perimeter monitor wells will be located no farther than 400 feet from the well field patterns. Refer to Powertech (2011) for additional information including perimeter monitor well spacing for stacked roll fronts. They will be evenly spaced with a maximum spacing of either 400 feet or the spacing that will ensure a 70 degree angle between adjacent perimeter monitor wells and the nearest injection well. This maximum distance is based on and consistent with standard monitoring practices at operating ISR facilities. It also is supported by site-specific data and evaluation through numerical groundwater modeling, which was submitted to NRC in support of the license application (Powertech, 2009b) and demonstrates that the maximum perimeter monitor ring spacing of 400 feet is adequate to detect an excursion and that an excursion can be controlled.

Perimeter wells will be screened across the entire thickness of the production zone, which will be determined following completion of delineation drilling for each well field. In cases where a localized confining unit is present between stacked ore bodies within one of the primary geologic units (Fall River or Chilson), the monitoring approach may be modified such that perimeter monitor wells are screened only within the portion of the hydrogeologic unit in which the ore body is located. In all cases, the screens will fully penetrate the hydrogeologic unit to be monitored, i.e., spanning the entire interval between the overlying and underlying confining beds. As described in Section 6.2.2, the Fuson Shale is pervasive throughout the project area and forms a confining unit between the Fall River and Chilson. No monitor well will be screened across the Fuson Shale. Prior to initiating ISR operations in each well field, pre-operational pumping tests will be conducted to confirm that the perimeter monitor wells are hydraulically connected to the production zone. Additional information is found in Section 8.2.3.

14.2.1.2 Non-Production Zone Monitor Wells

Depending on site-specific conditions, non-production zone monitor wells may consist of two types of monitor wells, termed overlying and underlying. The overlying and underlying monitor wells will be used to obtain baseline water quality data and used in the development of compliance limits for the overlying and underlying zones that will be used to determine if vertical migration of lixiviant is occurring. The screened zone for the overlying and underlying monitor wells will be determined from electric logs by qualified geologists or hydrogeologists. The following criteria will be applied for installing overlying and underlying monitor wells that are effective at detecting potential vertical excursions. These will be determined based on the hydrogeologic data obtained and analyzed during the development of each hydrogeologic well field data package (Section 8.2.4) and injection authorization data package (Section 8.2.5).

- Areas which may be associated with leakage around the injection well casing.
- Areas where the confining unit may be uncharacteristically thin or absent.
- Areas which may be associated with leakage through improperly abandoned boreholes.
- Areas identified during hydrologic testing as having hydraulic communication with the overlying or underlying aquifer.

If necessary, additional overlying and underlying monitor wells may be added beyond the minimum density specified below in order to detect a potential vertical excursion. Following is a description of each of the non-production zone monitor well types.

Overlying Monitor Wells

The overlying monitor wells will be designed to provide monitoring of any upward movement of ISR solutions that may occur from the production zone and to guard against potential leakage from production and injection well casing into any overlying aquifer. The term "overlying aquifer" refers to any hydrogeologic unit(s) above the production zone and separated by a confining layer. The terms "overlying aquifer" and "overlying hydrogeologic unit" are used interchangeably when describing well field design and operations.

All overlying hydrogeologic units will be monitored. Monitor wells completed in the first overlying hydrogeologic unit will be designated with the prefix MO and will have a density of at least one well per 4 acres of well field pattern area. Monitor wells completed in subsequent overlying hydrogeologic units will be designated with prefixes MO2, MO3, etc. and will have a density of at least one well per 8 acres of well field pattern area.

Underlying Monitor Wells

The underlying monitor wells will be designed to provide monitoring of any downward movement of ISR solutions from the production zone. Monitor wells completed in the first underlying hydrogeologic unit will be named with the prefix MU and will have a density of one well per 4 acres of pattern area. Only the first underlying hydrogeologic unit will be monitored, unless the production zone is the lowermost hydrogeologic unit above the Morrison Formation, in which case the Unkpapa Sandstone will be the underlying aquifer. Excursion monitoring will not occur in the Unkpapa Sandstone. The justification for not performing excursion monitoring is as follows:

1) The Unkpapa Sandstone shows substantially higher potentiometric head than the Fall River and Chilson throughout the permit area. During ISR operations, the potentiometric head will be reduced (creating a cone of depression) in the Chilson and Fall River due to a net withdrawal (production flow greater than injection flow) in order to maintain well field bleed. Flow into the Unkpapa from production zones in the Fall River and Chilson operating at a substantially lower potentiometric head would be impossible.
2) The Morrison Formation is prevalent across the entire permit area, with a thickness ranging from 60 to 140 feet, and will act as an aquitard to prevent flow between the Unkpapa and the Fall River and Chilson. This was demonstrated by the pumping tests conducted by Powertech, where no response occurred in the Unkpapa during pumping of either the Fall River or Chilson.
3) The Unkpapa is a low-yield aquifer determined by a recent water supply well installation by Powertech. Water samples from the Unkpapa can no longer be obtained from well 704 because this well was cemented off in the Unkpapa in 2009 and perforated in the Chilson due to low yield from the Unkpapa.

4) NRC guidance in NUREG/CR-6733 (NRC, 2001) allows that, "Where confining layers are shown to be very thick and of negligible permeability, requirements for vertical excursion monitoring can be relaxed or eliminated."

14.2.1.3 Monitor Well Layout

The generalized monitoring scheme is depicted in Figure 14.1. This approach will be used when there are no substantial confining layers between ore bodies within the Fall River or Chilson.

Local confining units within the Fall River or Chilson generally are anticipated to be utilized in the monitoring scheme. The presence or absence of these will be confirmed with delineation drilling and mapped in more detail in the process of developing each well field hydrogeologic data package (refer to Section 8.2.4). Figures 14.2 and 14.3 depict the conceptual monitoring schemes for the initial Burdock and Dewey well fields, respectively. Following is a brief summary of the conceptual monitor well layouts. Note that additional monitor wells may be installed as needed.

For Burdock Well Field 1 (Figure 14.2), the anticipated production zone is the Lower Chilson. Since the production zone is anticipated to be in the lowermost hydrogeologic unit above the Morrison Formation, no monitoring would occur in the underlying hydrogeologic unit (Unkpapa). Refer to the previous section for additional explanation. Monitor wells would be installed in the first overlying hydrogeologic unit (Middle Chilson) with a minimum density of one well per 4 acres. Monitor wells would be installed in all other overlying hydrogeologic units with a minimum density of one well per 8 acres. This includes the Upper Chilson, Lower and Upper Fall River, and alluvium (where present).

For Burdock Well Field 3 (Figure 14.2), the anticipated production zone is the Upper Chilson. In this case the immediately overlying hydrogeologic unit would be the Lower Fall River Formation and would be monitored at a minimum density of one well per 4 acres. Other overlying hydrogeologic units would be monitored at a minimum density of one well per 8 acres, including the Upper Fall River and alluvium (where present). The first underlying hydrogeologic unit would be the Middle Chilson and would be monitored at a minimum density of one well per 4 acres.

For Dewey Well Field 1 (Figure 14.3), the anticipated production zone is the Lower Fall River. In this case overlying hydrogeologic units would only include the Upper Fall River and alluvium (where present). The first underlying hydrogeologic unit would be the Upper Chilson. Similar conventions are shown for Dewey Well Fields 2 and 4.

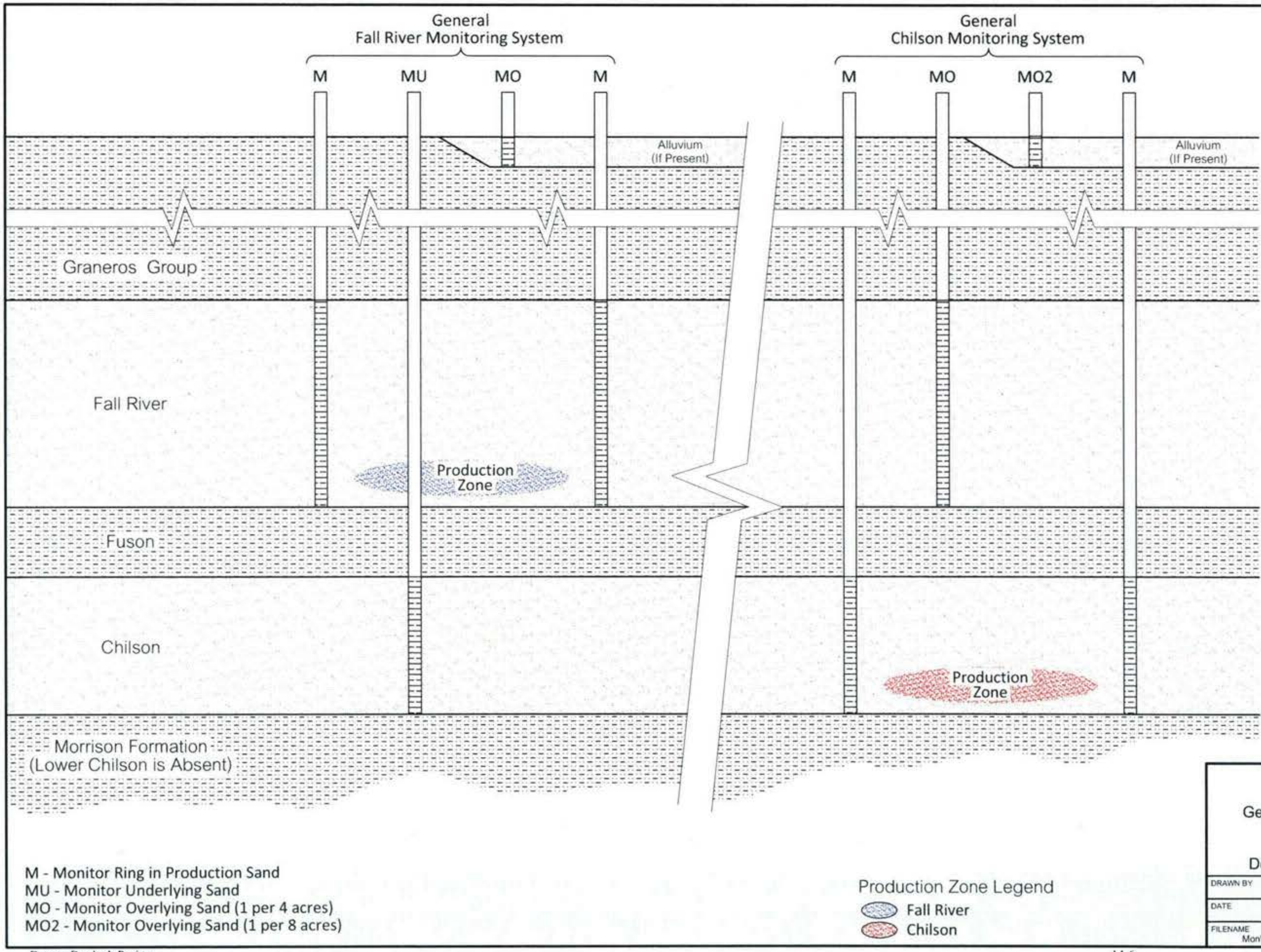


Figure 14.1

Generalized Monitor Well Configuration

Dewey-Burdock Project

DRAWN BY	Mays, Hetrick
DATE	24-Jul-2012
FILENAME	MonWell-GenConf.dwg

POWERTECH (USA) INC.

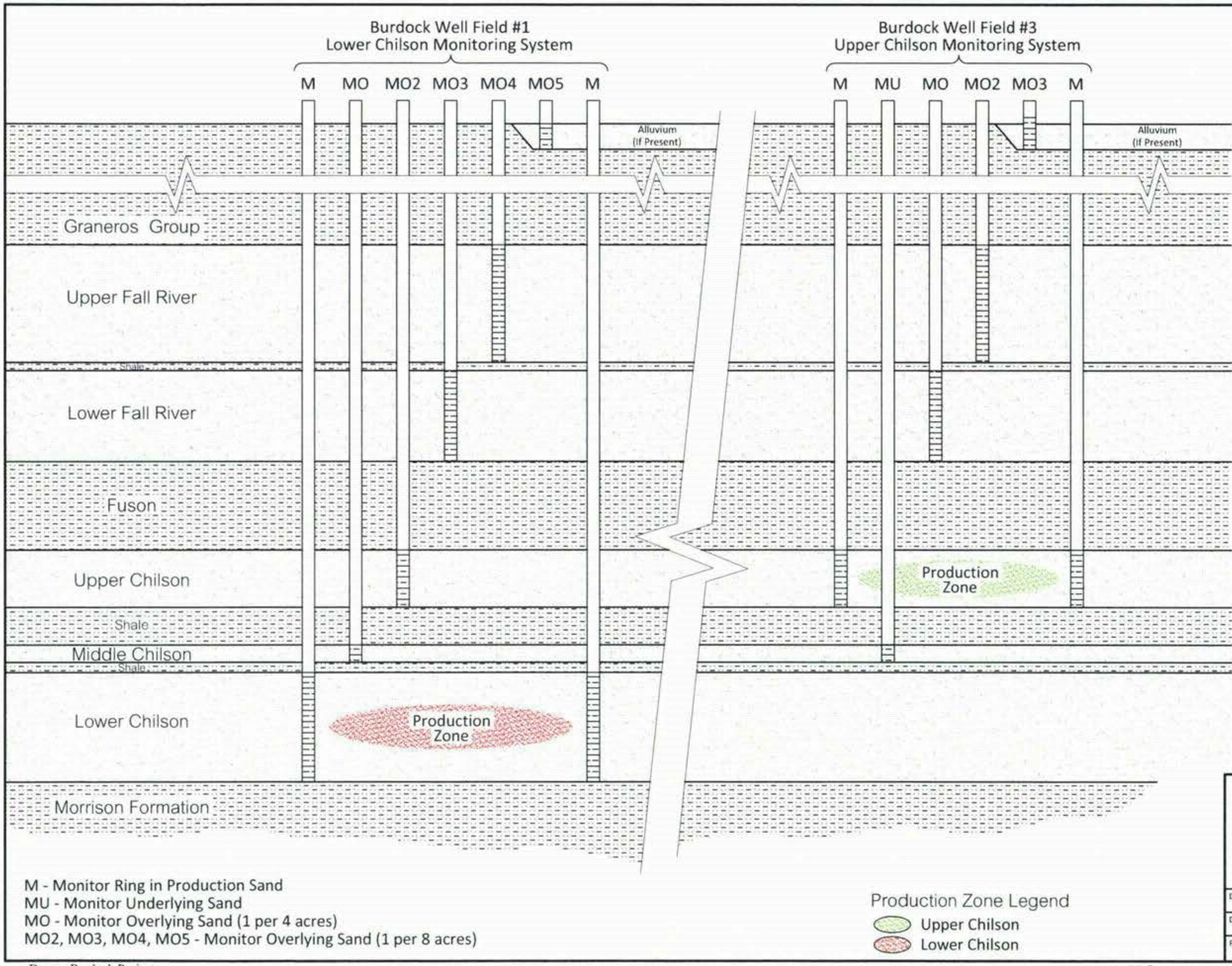


Figure 14.2

Anticipated Burdock Monitor Well Configuration

Dewey-Burdock Project

DRAWN BY	Mays, Hetrick
DATE	24-Jul-2012
FILENAME	MonWell-BurdConf.dwg

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Figure 14.3

Anticipated Dewey Monitor Well Configuration

Dewey-Burdock Project

DRAWN BY	Mays, Hetrick
DATE	24-Jul-2012
FILENAME	MonWell-DeweyConf.dwg

POWERTECH (USA) INC.

Refer to Powertech (2011) for additional details on monitor well layout, including instances where a producing well field will be located in an overlying or underlying hydrogeologic unit associated with another producing well field (i.e., overlapping well fields).

14.2.2 Establishing Upper Control Limits

Powertech will establish baseline water quality in the perimeter wells and non-production zone monitor wells according to NRC license requirements. Baseline water quality will be calculated based on the analysis of multiple samples from each monitor well. Baseline water quality will be used to establish upper control limits (UCLs). UCLs will be established as a function of the average baseline water quality and the variability in each parameter according to statistical methods approved by NRC.

UCLs will be established for constituents that provide early indication of a potential excursion. The anticipated excursion indicators include chloride, conductivity and total alkalinity. These are commonly used excursion indicators that are highly mobile in groundwater not influenced significantly by pH changes or oxidation-reduction reactions.

14.2.3 Excursion Sampling

Excursion sampling will occur in accordance with NRC license requirements. The sampling frequency will be twice monthly during uranium recovery operations and once every 60 days during aquifer restoration. As previously described, the anticipated excursion indicators include chloride, conductivity and total alkalinity. Water levels will be recorded during excursion sampling events.

Water levels will be measured using downhole pressure transducers or manual electronic meters. These measurements will alert operators to any significant change in the water levels within the monitor wells to provide an early warning of a potential excursion. Operators may then follow standard operating procedures to make adjustments to well field production and/or injection flow rates to avoid an excursion due to any unbalanced flow condition in a well field. Water level readings will be recorded at a minimum frequency of twice monthly from production zone monitor wells and monitor wells installed in the overlying and underlying hydrogeologic units.

14.2.4 Excursion Confirmation

An excursion will be deemed to have occurred if two or more excursion indicators in any monitor well exceed their UCLs. A verification sample will be taken within 48 hours after results of the first analyses are received. If the results of the verification sampling are not complete within 30 days of the initial sampling event, then the excursion will be considered confirmed for the purpose of meeting the reporting requirements described below. If the excursion is not

confirmed by the verification sample, a third sample will be taken within 48 hours after the second set of sampling data are received. If neither the second nor the third sample confirms the excursion by two indicators exceeding their UCLs, the first sample will be considered to have been in error, and the well will be removed from excursion status. If either the second or third sample exhibits two or more indicators above their UCLs, an excursion will be confirmed, the well will be placed on confirmed excursion status, and corrective action will be initiated. Corrective actions are described in Section 13.3.1.

14.3 Operational Groundwater Monitoring

Operational groundwater monitoring will be conducted in accordance with NRC license conditions and will be used 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. The operational monitoring program is designed to provide a comprehensive baseline evaluation of water supply wells located within the AOR. Wells to be included in the operational monitoring program include domestic wells within 2 km of the project area, stock wells within the project area, and additional monitor wells within the project area in the alluvium, Fall River, Chilson and Unkpapa.

Prior to operations all domestic and stock wells within 2 km of the project area will be sampled to establish baseline water quality. A complete list of the wells is provided in Appendix A. To meet NRC license requirements, Powertech will monitor all domestic and stock wells within 2 km of the project area quarterly for one year prior to operation (including monitoring already completed). All samples will be analyzed for constituents listed in Table 14.2.

<u>Operational Groundwater Monitoring - Domestic Wells</u>

Powertech has committed to NRC to remove all domestic wells within the project area from private use prior to ISR operations, or, at a minimum, from drinking water use. Depending on the well construction, location and screen interval, Powertech may continue to use the well for monitoring or plug and abandon the well. During operations, Powertech will monitor all domestic wells within 2 km of the project boundary. Samples will be collected annually and analyzed for the constituents listed in Table 14.2.

<u>Operational Groundwater Monitoring - Stock Wells</u>

During the design of each well field, all nearby stock wells will be evaluated for the potential to be adversely affected by ISR operations or to adversely affect ISR operations. At a minimum, all stock wells within ¼ mile of well fields will be removed from private use prior to operation of

Table 14.2: Baseline Water Quality Parameter List

Test Analyte/Parameter	Units	Analytical Method
Physical Properties		
pH ≠	pH units	A4500-H B
Total Dissolved Solids (TDS) +	mg/L	A2540 C
Conductivity	µmhos/cm	A2510 B
Common Elements and Ions		
Alkalinity (as $CaCO_3$)	mg/L	A2320 B
Bicarbonate Alkalinity (as $CaCO_3$)	mg/L	A2320 B (as HCO_3)
Calcium	mg/L	E200.7
Carbonate Alkalinity (as $CaCO_3$)	mg/L	A2320 B
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
Sodium, Na	mg/L	E200.7
Sulfate, SO_4	mg/L	A4500-SO4 E; E300.0
Trace and Minor Elements		
Arsenic, As	mg/L	E200.8
Barium, Ba	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
Iron, Fe	mg/L	E200.7
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
Uranium, U	mg/L	E200.7, E200.8
Vanadium, V	mg/L	E200.7, E200.8
Zinc, Zn	mg/L	E200.8
Radiological Parameters		
Gross Alpha††	pCi/L	E900.0
Gross Beta	pCi/L	E900.0
Radium, Ra-226§	pCi/L	E903.0

≠ Field and Laboratory

\+ Laboratory only

††Excluding radon, radium, and uranium

§ If initial analysis indicates presence of Th-232, then Ra-228 will be considered within the baseline sampling program or an alternative may be proposed.

nearby well fields. Depending on the well construction, location and screen interval, Powertech may continue to use the well for monitoring or plug and abandon the well. During operation, Powertech will monitor all stock wells within the project area. Samples will be collected quarterly and analyzed for water level and the three excursion indicators of chloride, total alkalinity, and conductivity.

Operational Groundwater Monitoring - Monitor Wells

Powertech will monitor wells located hydrologically upgradient and downgradient of ISR operations as part of the operational groundwater monitoring program. Monitor wells included in the operational monitoring program will include wells completed in the alluvium, Fall River, Chilson, and Unkpapa. The monitor wells will be monitored quarterly and analyzed for constituents listed in Table 14.2.

Operational Groundwater Sampling Methods and Parameters

Groundwater sampling methods will be in accordance with an accepted Quality Assurance Project Plan (see Section 14.7).

14.4 Groundwater Restoration Monitoring

During all phases of groundwater restoration, including active restoration and stability monitoring, excursion monitoring will continue in accordance with NRC license conditions. The following additional monitoring associated with groundwater restoration will be conducted in accordance with NRC license requirements.

14.4.1 Establishing Production Zone Baseline Water Quality

Production zone baseline water quality and TRGs will be established according to NRC license requirements. Prior to uranium ISR, a subset of wells within each well field to be utilized as production wells will be identified for baseline water quality sampling. The sample density is anticipated to be one well per 4 acres of well field pattern area or six wells, whichever is greater, except that fewer than six wells may be used for well fields smaller than 6 acres. The expected sample frequency is four sample events spaced at least 14 days apart, with samples analyzed for the constituents listed in Table 14.2. Baseline water quality and TRGs will be established according to statistical methods approved by NRC.

14.4.2 Monitoring during Active Restoration

Powertech will monitor the progress of aquifer restoration by sampling ore zone monitor wells in each well field at a frequency sufficient to determine the success of aquifer restoration, optimize the efficiency of aquifer restoration, and determine if any areas need additional attention. The results of active restoration monitoring will be used to evaluate potential areas of flare or hot

spots. If potential flare or hot spots are identified, appropriate corrective measures will be taken such as adjusting the flow in the area, changing wells from injection to production, or adjusting the restoration bleed in a specific area.

14.4.3 Restoration Stability Monitoring

A groundwater stability monitoring period will be implemented to show that the restoration goal has been adequately maintained. The stability monitoring period proposed in the NRC license includes 12 months with quarterly sampling (at least five sample events, including one at the beginning of the stability monitoring period and following each of the following four quarters). The sample results will be analyzed using statistical methods approved by the NRC to evaluate stability.

If a constituent does not meet the stability criteria, Powertech will take appropriate action considering the constituent and the status of the restored groundwater system. Potential actions may include extending the stability period or returning the well field to a previous phase of active restoration to resolve the issue.

If the analytical results from the stability period continue to meet the TRGs and meet the stability criteria, then Powertech will submit supporting documentation to the NRC showing that the restoration parameters have remained at or below the restoration standards and requesting that the well field be declared restored.

14.5 Reporting

Prior to operation of each well field, Powertech will prepare and submit an injection authorization data package as described in Section 8.2.5. The data package will provide the planned locations of injection, production and monitor wells and the results of formation testing. The data packages will request authorization to initiate injection into each well field. Powertech will complete MIT and a well completion report for each injection well prior to initiating injection into that well.

Quarterly monitoring reports will be submitted to EPA Region 8. At minimum, the quarterly monitoring reports will include the following information:

- Physical, chemical and other relevant characteristics of injection fluids
- Monthly average, maximum and minimum values for injection pressure, flow rate and volume
- Quarterly MIT results, a list of any wells failing MIT and corrective actions taken, and a list of wells anticipated to undergo MIT during the next quarter
- Any well maintenance activities

Appendix K contains an example of the quarterly monitoring report form (EPA Form 7520-8, Rev. 8-01).

Signed quarterly reports will be submitted electronically unless otherwise directed by the EPA. If required, a signature letter from the Project Manager will accompany the disk to certify the report. Reports will consist of monthly summary information for the project. Monitoring reports will include raw data and graphical analysis for the current reporting period to date. Each calendar quarter, the maximum, minimum, and average monthly values for each continuously monitored parameter specified for the injection wells will be tabulated. A narrative description of any deviations from permit limitations will be given. Maintenance activities, MIT activities, and other significant events that took place during the reporting period will be described. If an excursion has potential to impact a USDW, it will be reported verbally to EPA within 24 hours and followed up within 5 days in written form.

14.6 Recordkeeping

Well completion records and all monitoring information, including calibration and maintenance records and data from the continuous monitoring instrumentation will be retained for at least three (3) years after all wells have been plugged and abandoned. This includes:

- Injection well completion reports.
- Information on the nature, volume, and composition of all injected fluids.
- MIT results, description and results of any other tests required by EPA, and any well work-overs completed.

The records discussed above (originals or copies) will be retained on site unless written approval to discard the records is provided by the EPA. Copies of these records (or originals) will be maintained for all observation records throughout the operating life of each well. Powertech also will maintain an electronic database containing well completion and MIT records for all injection wells. The database will be provided for EPA use upon request.

14.7 Quality Assurance

After license issuance but prior to operations, Powertech will prepare and submit to NRC a Quality Assurance Project Plan (QAPP) consistent with the recommendations contained in NRC Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Inception through Normal Operations to License Termination) -- Effluent Streams and the Environment. The purpose of the QAPP is to ensure that all radiological and nonradiological measurements that support the radiological monitoring program are reasonably valid and of a defined quality. These programs are needed (1) to identify deficiencies in the sampling and measurement

processes and report them to those responsible for these operations so that licensees may take corrective action and (2) to obtain some measure of confidence in the results of the monitoring programs to assure the regulatory agencies and the public that the results are valid.

15.0 ATTACHMENT Q - PLUGGING AND ABANDONMENT PLAN

This attachment describes the plugging and abandonment plan for the Class III injection wells. The plugging and abandonment methods are designed to prevent movement of fluids through the well, out of the production zone, and into USDWs or the land surface. The same procedures will be followed for production and monitor wells. The attachment also summarizes the surface reclamation, decontamination and decommissioning activities that will be carried out in accordance with NRC license and DENR permit requirements.

15.1 Well Plugging and Abandonment Plan

Powertech will plug all wells in accordance with ARSD 74:02:04:67 with bentonite or cement grout. The weight and composition of the grout will be sufficient to control artesian conditions and meet the well abandonment standards of the State of South Dakota. Cementing will be completed from total depth to surface using a drill pipe. Records will be kept of each well cemented including at a minimum the following information:

- well ID, total depth, and location
- driller, company, or person doing the cementing work
- total volume of grout placed down hole
- viscosity and density of the grout

Powertech will remove surface casing or cut off surface casing below ground and set a cement surface plug on each well plugged and abandoned.

15.2 Plugging and Abandonment Reporting

According to 40 CFR § 144.51(p) the operator is to notify the EPA within 60 days after plugging or at the time of the next quarterly report (whichever is less). In accordance with this requirement, a Plugging and Abandonment Report will be submitted to the EPA. The person that performs the plugging operation will certify the report as accurate. The report will contain either:

- A statement that the well was plugged in accordance with the approved Plugging and Abandonment Plan; or
- If the actual plugging differed from the Plugging and Abandonment Plan, a statement specifying the different procedures followed.

Documentation will 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.

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

15.3 Facility Decontamination and Decommissioning

Following regulatory approval of successful aquifer restoration in all well fields, Powertech will decommission all well fields, processing facilities, ponds, and equipment within the project area. Decontamination and decommissioning activities will be done in accordance with NRC license and DENR large scale mine permit requirements. During decommissioning, all well field equipment (including pumps, tubing, pressure transducers, wellhead covers and surface piping and equipment), pipelines, header houses, processing buildings/equipment, and pond liners will be surveyed for radiological contamination and decontaminated for unrestricted release, transferred to an NRC or NRC agreement state-licensed facility, or disposed at an appropriately permitted facility. Surface soils will be surveyed for radiological contamination and affected soils removed and appropriately disposed. Surface reclamation and revegetation will be conducted in accordance with DENR large scale mine permit requirements. The decommissioning program will ensure that the project area is closed in a manner that permits release for unrestricted use.

16.0 ATTACHMENT R - NECESSARY RESOURCES

This attachment demonstrates that the necessary resources will be available to plug and abandon the injection wells. Table 16.1 presents a preliminary estimate of the cost to plug and abandon the injection wells that will be in place at the end of the first year of ISR operations. The preliminary cost estimate is based on the anticipated number of installed injection wells and cost estimates from independent contractors to plug and abandon the injection wells and to supply cement grout (refer to Appendix L for cost estimates). The preliminary estimate in Table 16.1 is subject to change prior the Class III UIC permit issuance based on ongoing facility planning efforts. The number of injection wells installed during the first financial assurance period, which is anticipated to be the first year after license/permit issuance, may be significantly fewer, since most of this time period will be used for well field delineation, monitor well installation, and preparation of the well field hydrogeologic and injection authorization data packages. Powertech anticipates submitting a revised financial assurance estimate for EPA approval prior to Class III UIC permit issuance.

Table 16.1: Preliminary Well Plugging and Abandonment Cost Estimate

	Value	Units	Source
Assumptions			
Total injection wells to be plugged and abandoned	411	wells	Powertech (2011)
Average well depth	550	ft	Burdock ~450'; Dewey ~600'
Inside casing diameter	4.90	in	5" SDR 17 PVC
Quantity Calculations			
Plugging volume per well	72.0	ft^3	Calculated
Volume cement grout per 94-lb bag	1.27	ft^3	Assumes approximately 6 gal. water per bag
Volume cement grout per ton bulk cement	27.0	ft^3/ton	Calculated
Mass cement per well	2.7	tons	Calculated
Unit Cost Estimates			
Equipment and Labor (includes water and water hauling)			
Wells plugged per week per 3-man crew	16	wells	Quote
Equipment and labor cost per well	$1,000	$/well	Quote
Bulk cement			
Bulk cement cost	$140.42	$/ton	Quote
Cement cost per well	$380	$/well	Calculated
Cement storage pig rental			
Rental cost per week	$625	$/week	Quote
Rental cost per well	$40	$/well	Calculated
Total cost per well	$1,420	$/well	Calculated
Total cost estimate	**$583,620**		Calculated

Following review and approval of the plugging and abandonment cost estimate, a financial assurance instrument will be submitted to EPA to assure the required plugging and abandonment activities will be completed to safeguard potential USDWs.

Each year Powertech will submit a financial assurance update indicating the anticipated number of injection wells to be installed during the next year and providing an updated financial assurance instrument to include the plugging and abandonment costs for the additional injection wells. During decommissioning, the financial assurance instrument will be updated annually to reflect the wells injection plugged and abandoned during the previous year.

17.0 ATTACHMENT S - AQUIFER EXEMPTION

This attachment describes the requested aquifer exemption boundary for the Dewey-Burdock Project. An aquifer exemption is required to inject lixiviant for the purpose of extracting uranium. The aquifer exemption from protection as a drinking water source is requested for portions of the Inyan Kara Group on the basis that these portions do not currently serve as sources of drinking water and are anticipated to be commercially mineral producing.

17.1 Introduction

40 CFR § 146.4 allows EPA to exempt an aquifer or portion of an aquifer for the purpose of injection provided:

(a) It does not currently serve as a source of drinking water; and

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

  (1) 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 quality and location are expected to be commercially producible.

  (2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

  (3) It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or

  (4) It is located over a Class III well mining area subject to subsidence or catastrophic collapse; or

(c) The total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/L and it is not reasonably expected to supply a public water system.

The following sections describe the basis for the requested aquifer exemption, which include:

- The proposed exempted aquifer does not currently serve as a source of drinking water, and
- The proposed exempted aquifer is capable of producing minerals and contains minerals that considering their quantity and location are expected to be commercially producible.

The requested horizontal and vertical extents of the aquifer exemption boundary (AEB) are provided along with additional information in support of the aquifer exemption request, including proximity of drinking water wells, commercial producibility of the ore deposits, a description of the requested exempted aquifer, quality of water in the requested exempted aquifer, and ISR process considerations.

17.2 Requested Aquifer Exemption Boundary

The requested AEB is depicted on Figure 17.1 and includes currently identified potential well field areas, the associated perimeter monitor well rings, and an additional area outside the perimeter monitor well rings for which scientific justification is provided in Section 17.2.1. The requested AEB includes portions of Section 29-35, Township 6 South, Range 1 East, Custer County, South Dakota and Sections 1-3, 10-12, and 14-15, Township 7 South, Range 1 East, Fall River County, South Dakota. The justification is provided below for the horizontal and vertical extents of the requested AEB. When developing the requested AEB, Powertech considered the following:

- 40 CFR § 146.4, Criteria for Exempted Aquifers
- Ground Water Protection Branch Guidance 34 (EPA, 1984)
- Meetings with EPA Region 8 staff
- The recent (August 2011) precedent for the Lost Creek Project AEB in Wyoming based on similar criteria

17.2.1 Horizontal Boundary Justification

The requested AEB depicted on Figure 17.1 includes the currently identified potential well field areas, the perimeter monitor well rings 400 feet from the potential well field areas, and an additional area 120 feet outside of the perimeter monitor well rings. The additional area is based on a science-based calculation that considers the distance that a potential excursion could travel prior to being detected and recovered. The justification is included in Appendix M and summarized below.

Based on meetings between Powertech and EPA Region 8 staff, it was agreed that the aquifer exemption request should include some distance beyond the monitor well ring and that a scientific approach would be used similar to that recently approved for the Lost Creek Project AEB. The proposed distance past the monitor well ring is calculated using the following equation:

$$\Delta E_b = \Delta T + \Delta d + DF$$

where ΔE_b is the distance beyond the perimeter monitor well boundary requested for inclusion in the exempted aquifer, ΔT is the calculated distance that a potential excursion could extend beyond a monitor ring outline before being detected at a perimeter monitor well, Δd is the distance that a potential excursion could travel from the time of initial detection to the time that recovery operations are implemented, and DF is a dispersivity factor.

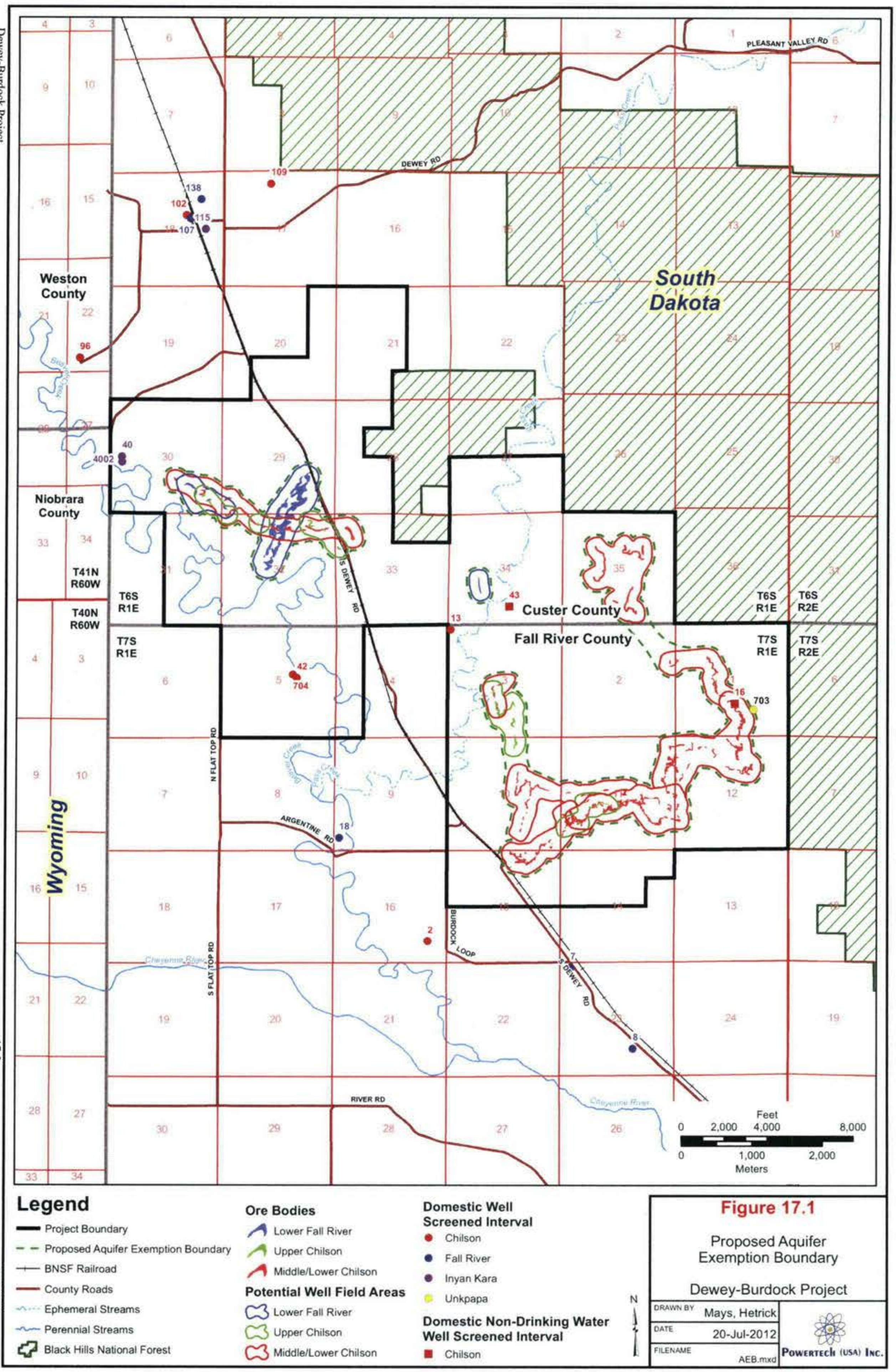


Figure 17.1

Proposed Aquifer Exemption Boundary

Dewey-Burdock Project

The maximum distance that a potential excursion could travel before detection (ΔT) is approximately 47 feet based on the geometry of the monitor 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 well field imbalance that could cause an excursion. The dispersion factor (DF) is estimated as 10 percent of the total travel distance or 47 feet. The science-based calculation of 118 feet for ΔE_b was rounded to 120 feet for ease of surveying and plotting on maps. A distance of 120 feet provides a reasonable extension beyond the monitor ring boundary to conduct uranium recovery while remaining protective of USDWs.

17.2.2 Vertical Boundary Justification

The requested vertical extents of the AEB include the entire Inyan Kara Group. This includes the Fall River Formation and Chilson Member of the Lakota Formation, which contain the uranium mineralization targeted for ISR. As described in Sections 6.2.2 and 17.5.2, the Inyan Kara Group is bounded above throughout most of the project area by the Graneros Group shales, which serve as the uppermost confining unit for ISR operations. The Inyan Kara Group is bounded below throughout the entire project area by the Morrison Formation, which is the lowermost confining unit for ISR operations.

17.3 Proximity to Drinking Water Wells

Figure 17.1 depicts the requested AEB in relation to domestic wells. This figure shows that there is one domestic, non-drinking water well within the requested AEB. Powertech has executed an agreement with the owner of Well 16 that prohibits this well from being used for drinking water. Under the agreement the well owner may continue to use the well for other, non-drinking or culinary domestic uses such as laundry and sanitary use. Powertech will provide drinking water to the Well 16 owner through a replacement well drilled in a formation deeper than the Inyan Kara Group, a water supply pipeline, or bottled water. No other domestic wells (drinking or non-drinking water) are within the requested AEB and completed in the Inyan Kara Group.

Aside from Well 16, only one domestic well is within ¼ mile of the requested AEB and completed in the Inyan Kara Group. Well 43 was formerly used as a domestic well but is now associated with an uninhabitable residence. Powertech has committed to plugging and abandoning this well if land application is used in the Burdock area. If land application is not used, well 43 will be converted to a monitor well or plugged and abandoned. Powertech has an agreement with the well 43 owner to remove the well from private use. No currently used

drinking water wells are within ¼ mile of the requested AEB and completed in the Inyan Kara Group.

17.4 Commercial Producibility of the Ore Deposits

The commercial producibility of the Dewey-Burdock Project is demonstrated by the Preliminary Economic Assessment of the Dewey Burdock Project (SRK, 2012). The Preliminary Economic Assessment was originally filed on July 14, 2010 and updated on February 8, 2011 and April 17, 2012. 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. The document was completed by a third party and confirms the resource calculations as well as the technical and economic viability of uranium recovery by ISR methods at the Dewey-Burdock Project. The report demonstrates the economic viability of the Dewey-Burdock Project using only a fraction of the historical TVA resource estimate within the project area of approximately 23 million pounds U_3O_8. Plate 17.1 depicts the historical TVA resource map.

17.5 Requested Exempted Aquifer Properties

The aquifer proposed for exemption is the Inyan Kara Group. The Inyan Kara Group contains the Fall River Formation and Chilson Member of the Lakota Formation, which contain the uranium mineralization proposed for ISR. The Inyan Kara Group within the proposed AEB has the geologic and hydrologic features that make a uranium deposit suitable for ISR as detailed in NRC (2009) based on Holen and Hatchell (1986):

- The deposit geometry generally is horizontal and of sufficient size and lateral continuity to economically extract uranium.
- The sandstone host rock is permeable enough to allow the ISR solutions to access and interact with the uranium mineralization.
- The major confining units (Graneros Group, Fuson Shale and Morrison Formation) plus local confining units within the Fall River and Chilson will prevent ISR solution from migrating vertically into overlying or underlying aquifers.
- The mineralization targeted for ISR is located in a hydrologically saturated zone.

17.5.1 Aquifer Elevation and Thickness

Within the project area, the elevation of the top of the Inyan Kara Group (i.e., Fall River Formation) ranges from approximately 3,050 feet in the western portion of the project area to approximately 3,900 feet in the eastern portion of the project area, where the Fall River Formation crops out. The elevation of the base of the Inyan Kara Group (i.e., base of the Chilson

Member) ranges from approximately 2,700 to 3,600 feet. The thickness of the Inyan Kara Group averages approximately 350 feet within the project area.

Within the requested AEB, the depth to the top of the Inyan Kara Group ranges from approximately 0 to 550 feet.

17.5.2 Confining Formations

Section 6.2.2 describes the major confining units across the project area. The Inyan Kara Group is confined above by the Graneros Group except where the Fall River Formation crops out in the eastern portion of the project area. Section 5.2.1.3 describes how analyses of core samples of the Skull Creek Shale, which is the lowest member of the Graneros Group and directly overlies the Fall River Formation, indicate low vertical permeabilities on the order of 6.8×10^{-9} cm/sec (0.007 millidarcies). The thickness of the Graneros Group ranges from 0 to more than 500 feet within the project area.

As described in Section 10.5, the only area where the Fall River Formation is geologically unconfined is in the eastern portion of the project area. Powertech does not propose to conduct ISR operations in the Fall River in this area. The Chilson throughout the project area is physically and hydraulically isolated from the overlying Fall River Formation by the Fuson Shale. The Fuson Shale consists of 20 to 80 feet of low-permeability shales and clays, with vertical permeabilities estimated from core samples to range from 7.8×10^{-9} to 2.2×10^{-7} cm/sec (0.008 to 0.228 millidarcies).

Throughout the entire project area the Inyan Kara Group is confined below by the Morrison Formation, which is a low-permeability shale unit with a thickness of 60 to 140 feet. Analyses of core samples have shown the vertical permeability to be very low and range from 3.9×10^{-9} to 4.2×10^{-8} cm/sec (0.004 to 0.04 millidarcies).

17.5.3 Hydraulic Properties

Hydraulic properties of the Fall River Formation and Chilson Member of the Lakota Formation have been determined from TVA and Powertech pumping tests as described in Section 8.2. Table 17.1 summarizes the approximate range of transmissivity, storativity, and hydraulic conductivity determined from these tests. The hydraulic properties of each well field will be determined prior to operations as described in Section 8.2.3.

Table 17.1: Hydraulic Properties of the Fall River Formation and Chilson Member of the Lakota Formation from Pumping Tests

Aquifer	Transmissivity	Hydraulic Conductivity	Storativity
Fall River	54 - 255 ft^2/day	0.4 - 1.8 ft/day	1.4 E-05 - 4.6 E-05
Chilson Member	150 - 590 ft^2/day	0.9 - 3.1 ft/day	1.0 E-04 - 1.8 E-04

17.6 ISR Process Considerations

17.6.1 Lixiviant Compatibility with Ore Body

The lixiviant will consist of groundwater pumped from the production zone and fortified with dissolved oxygen and carbon dioxide. As described in Section 7.3, this lixiviant formulation is consistent with that used in typical U.S. ISR operations, will minimize potential groundwater quality impacts during uranium recovery, and will enable restoration goals to be achieved in a timely manner.

The effectiveness of this type of lixiviant is demonstrated by leach amenability studies conducted on core samples collected within the project area. The leach amenability study results are provided in the Preliminary Economic Assessment of the Dewey-Burdock Project (SRK, 2012) and summarized as follows.

Leach amenability studies were conducted at Energy Laboratories in Casper, Wyoming in July and August 2007. Sequential leach bottle roll tests were conducted on four core intervals sampled from the Fall River and Chilson ore-bearing sandstones within the project area. The lixiviant was prepared using hydrogen peroxide and sodium bicarbonate dissolved in deionized water. This is the same type of lixiviant proposed for ISR but using chemicals compatible with ambient pressure leach studies (i.e., hydrogen peroxide as the oxidant and bicarbonate as the complexing agent instead of gaseous oxygen and carbon dioxide, which cannot be dissolved in sufficient quantities at ambient pressure).

In each test, a crushed ore sample was successively contacted with approximately 30 pore volumes of lixiviant. Tails analysis indicated recovery efficiencies of 71% to 98%. The Preliminary Economic Analysis concludes that, "These preliminary leach tests indicate that the uranium deposits at Dewey-Burdock appear to be readily mobilized in oxidizing solutions and potentially well suited for ISR mining."

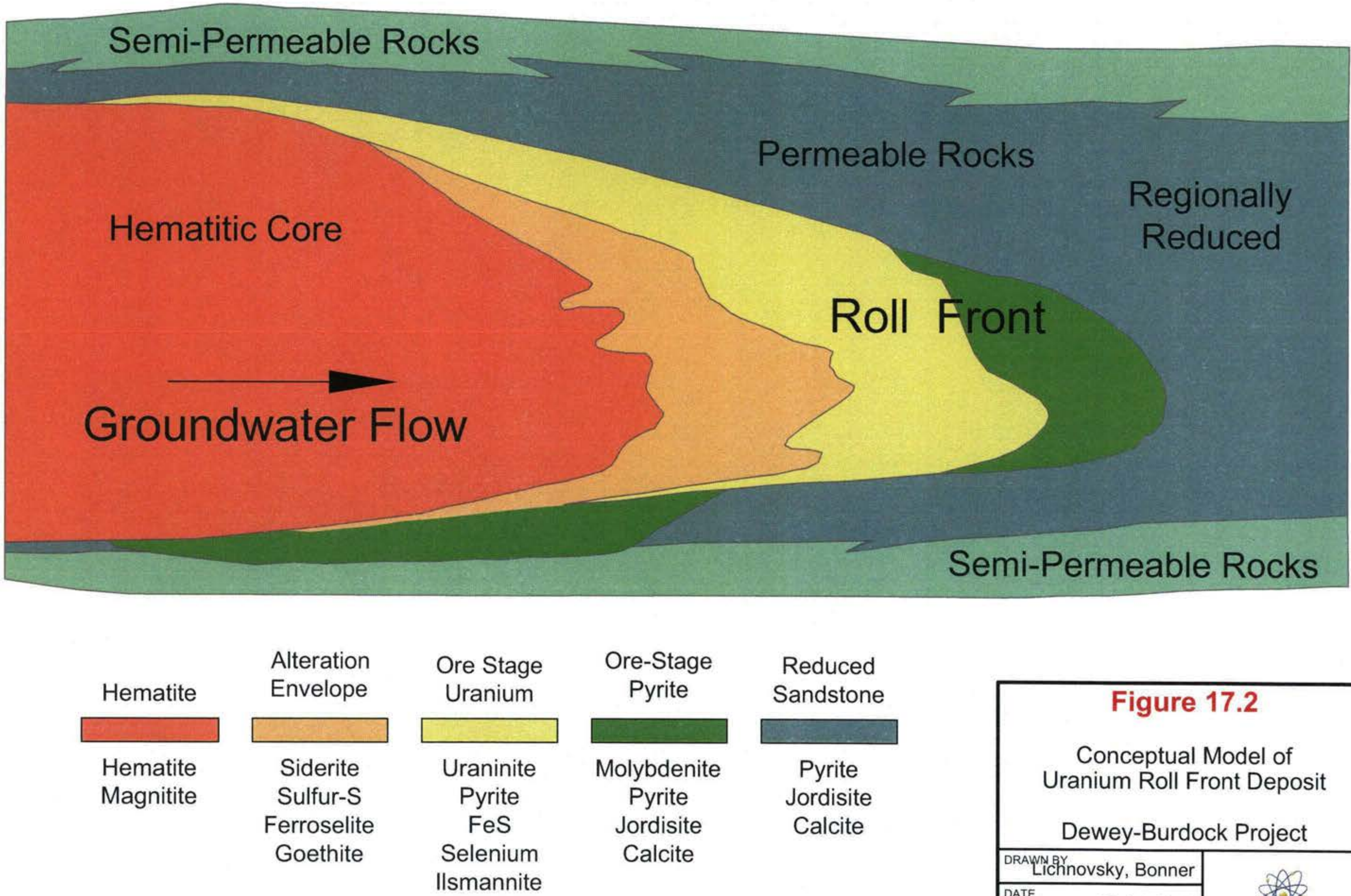
17.6.2 Mineralogy of the Uranium Ore

Uranium deposits within the project area are classic, sandstone, roll-front type deposits, located along oxidation-reduction boundaries, similar to those in Wyoming, Nebraska and Texas. These type deposits are usually "C" shaped in cross section, with the concave side of the deposit facing up-dip, toward the outcrop. Roll-front deposits are a few tens of feet to 100 or more feet wide and often thousands of feet long. It is generally believed these epigenetic uranium deposits are the result of uranium minerals leached from the surface environment, transported downgradient by oxygenated groundwater and precipitated in the subsurface upon encountering a reducing environment at depth. These roll-front deposits are centered at and follow the interface of naturally occurring chemical boundaries between oxidized and reduced sands (See Figure 17.2). Roll-front deposits similar to those in the project area are generally described in NRC (2009).

Within the project area, roll-front deposits occur at depths ranging from less than 100 feet in the outcrop area of the Fall River Formation up to 800 feet in sands of the Chilson Member of the Lakota Formation in the northwestern part of the project area. The mineralized sandstones are typically fine to medium-grained quartz sands that are moderately to very well sorted and show sub-angular to sub-rounded grain angularity. Scattered pyrite concretions up to 1" in diameter are sometimes present as are very thin carbonaceous stringers and very well cemented calcite zones. The average thickness of this mineralization is 4.6 feet and the average grade is 0.21 percent U_3O_8 in the project area.

There is a geochemical "footprint" associated with these uranium roll-front systems, consisting of 1) a reduced zone, 2) an oxidized zone, and 3) an ore zone. The following is a geological and geochemical description of each of these zones for uranium deposits within the project area. Information included in this description was obtained from a 1971 petrographic study of core samples from the Dewey portion of the project area by Homestake-Wyoming Partners utilizing microscopic, thin section, polished section, X-ray powder diffraction and spectrographic analyses (Honea, 1971).

> **Reduced Zone** – This zone represents the original character of the Inyan Kara sediments, unaffected by any mineralizing events. Today, it is the unaltered portion of the system, ahead of or down-gradient of the roll front. Reduced sandstones are grey in color, pyritic and/or carbonaceous. Organic material consists of carbonized wood fragments and interstitial humates. 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. This disseminated pyrite resulted from replacement of original iron (magnetite or similar minerals) and organic material. This early-stage pyrite precipitation contains trace amounts of transition metals (Cu, Ni, Zn, Mo and Se) and



Source: Uranium Geology and Exploration, 1978, Richard H. DeVoto

Figure 17.2

Conceptual Model of Uranium Roll Front Deposit

Dewey-Burdock Project

DRAWN BY Lichnovsky, Bonner	POWERTECH (USA) INC.
DATE 12-Jul-2012	
FILENAME DeVotoRollFrontConcept.dwg	

resulted from either biogenic (bacterial) or inorganic reduction of groundwater sulfate. Plagioclase and potassium feldspar clasts are fresh and, with the exception of localized areas of calcite cementing, calcite is sparse - averaging only 0.15%. A heavy mineral suite (ranging from trace to 3%) of tourmaline, ilmenite, apatite, zircon and garnet is typical of those found in mature, siliceous sandstones.

Oxidized Zone – This portion of the system, behind or upgradient of the roll front, is characterized by the presence of iron oxides resulting in a brown, pink, orange or red staining of host sandstones. The oxidized zone marks the progression of the down-gradient movement of mineralizing solutions through the host sandstones. Within the oxidized zone, original iron has been altered and is present as hematite or goethite as grain coatings, clastic particles or as pseudomorphs after original pyrite. 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 roll front. 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, where quartz particles show solution or etching effects and feldspars have been replaced with clays.

In the oxidation process of the original pyrite, it is believed the transition metals (Cu, Ni, Zn, Mo and Se) were liberated and incorporated into the mineralizing solution. This solution was slightly alkaline, initially having a positive oxidation potential. Uranium was in solution as the anionic uranyl dicarbonate complex. Other metals associated with uranium were also carried in anionic complexes. Within the project area, the oxidized zone in Inyan Kara sands has been mapped over a lateral distance of 15 miles and found to extend up to 4-5 miles down-dip from the outcrop.

Ore Zone – This portion of the system is located at the oxidation/reduction boundary where metals were precipitated when mineralizing solutions encountered a steep Eh (oxidation/reduction potential) gradient and a strongly negative oxidation potential. Sandstones in this zone are greenish-black, black, or dark grey in color. The primary uranium minerals are uraninite and coffinite, which occur interstitial to and coating sand grains and as 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. The high concentrations of uranium and vanadium within the ore zone indicate the original source of these metals was external to the Inyan Kara sediments.

Transition metals were also precipitated at or adjacent to the oxidation/reduction boundary. Native arsenic and selenium are found adjacent to the uranium, in the oxidized portion of the front - filling pore spaces between quartz grains. Molybdenum is found as jordisite adjacent to the uranium on the reduced portion of the front. 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 overlying tuffaceous material which is believed to be the source of the uranium and vanadium.

Late stage deposition of calcite and pyrite also appear to be part of the ore-forming process. Filling of pore spaces by nodular and concretionary calcite is found with the uranium mineralization and extending out into the reduced portion of the front. It is believed that uranium was transported as a uranyl dicarbonate complex and carbonate deposition took place along with the precipitation of uranium. Late stage, coarse grained, nodular or concretionary pyrite is also found associated with uranium ore and adjacent to the uranium in the reduced portion of the front.

17.6.3 Well Field Construction and Completion

Section 11 (Attachment M) describes the well construction materials and methods. Typical well casing will be 4.5 to 6-inch nominal diameter PVC with at least SDR 17 wall thickness. Powertech will adhere to the requirements of ASTM F480 and manufacturer's criteria to ensure that the installations do not exceed the casing hydraulic collapse resistance. Casing joints will be mechanical joints with watertight O-ring seals and high-strength nylon splines to ensure watertight joints. The drill holes will be at least 2 inches larger than the outside well casing diameters, and the annular spaces will be pressure-grouted with sufficient additional grout to achieve return to surface. Centralizers will be used to ensure the casings are centered in the holes. After allowing the grout to set, the target completion zone will be underreamed and a well screen assembly will be centralized and sealed inside the casing using K packers. Filter sand will be placed between the well screen and formation. Geophysical logs will be used to determine the target completion intervals.

17.6.4 Mechanical Integrity Testing

Section 11.5 describes MIT that will be performed on all injection, production, and monitor wells prior to operation, at least every 5 years, and following any repair where a downhole drill bit or underreaming tool is used. For injection wells, MIT will be performed at 125 percent of the maximum operating pressure of the well field, 125 percent of the maximum operating pressure of the well casing, or 90 percent of the formation fracture pressure, whichever is less. A well must maintain 90 percent of the MIT hydrostatic test pressure for a minimum of 10 minutes to pass the test.

17.6.5 Hydraulic Well Field Control

Section 10.4 describes how Powertech will maintain hydraulic control of each well field from the first injection of lixiviant through the end of aquifer restoration. This will be done by maintaining a production and restoration bleed, which will create a cone of depression within each well field. The typical production bleed is estimated at 0.875%, and the typical restoration bleed will range from about 1 to 17%. Verification of hydraulic control will be performed through water level measurements in perimeter monitor wells.

17.6.6 Groundwater Monitoring

Section 14.2 describes the excursion monitoring program that will be conducted to detect potential horizontal or vertical excursions of ISR solutions. Perimeter monitor wells will be completed in the ore zone around the perimeter of each well field at a maximum distance of 400 feet from the well field. They will be used to monitor any potential horizontal migration of fluid outside the production zone and to determine baseline water quality and characterize the area outside of the production pattern area. Non-production zone monitor wells will consist of overlying and underlying monitor wells that will be used to monitor any potential vertical migration of ISR solutions. Monitor wells will be sampled during uranium recovery and aquifer restoration operations. Corrective actions will be initiated in the event of an excursion to correct a potential well field balance and recover ISR solutions well before they can reach the AEB (refer to Section 13.3.1).

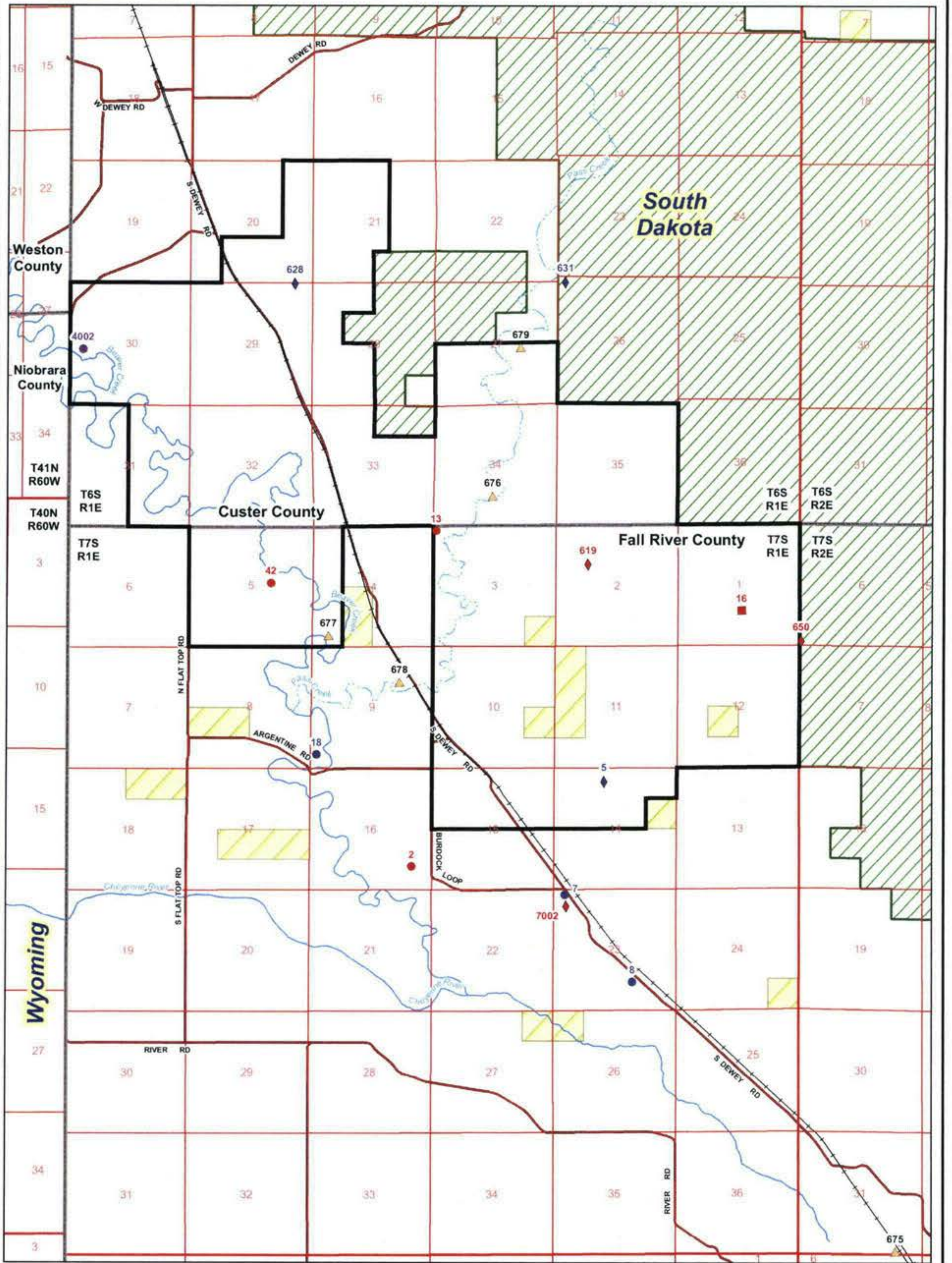
Section 14.3 describes the operational groundwater monitoring program that will be used to detect potential changes in groundwater quality in and around the project area as result of ISR operations. The operational groundwater monitoring program will include domestic wells, stock wells, and wells located hydrologically upgradient and downgradient from ISR well fields.

17.7 Water Quality of the Requested Exempted Aquifer

This section describes the results of baseline water quality sampling in the Inyan Kara Group within the project area, including the Fall River and Chilson Member of the Lakota formations. Water quality summary tables for the Inyan Kara Group and other aquifers (alluvium and Unkpapa) are provided in Appendix N, and analytical data are provided in Appendix O. Additional baseline characterization of the requested exempted aquifer will occur as part of the development of the well field hydrogeologic data packages described in Section 8.2.4.

17.7.1 Groundwater Monitoring Network and Parameters

Baseline groundwater sampling was conducted in accordance with NRC Regulatory Guide 4.14 (NRC, 1980b) as appropriate to ISR operations. The wells were selected based on type of use, aquifer, and location in relation to the ore bodies. For the NRC license baseline study, 19 wells (14 existing and 5 newly drilled) were selected in response to an NRC suggestion to characterize point of contact water quality and water within overlying, production, and underlying aquifers (Figure 17.3, Table 17.2). The wells selected for quarterly sampling included domestic, stock, and monitor wells. The subset included wells within the Fall River Formation, Chilson Member of the Lakota Formation, Inyan Kara Group (Fall River and Chilson), and alluvium. Initial



Legend

- Permit Boundary
- BNSF Railroad
- County Roads
- Ephemeral Streams
- Perennial Streams
- BLM Land
- Black Hills National Forest

Screened Interval

- Alluvium
- Fall River
- Inyan Kara
- Chilson

Well Use

- Monitor
- Stock
- Domestic
- Domestic Non-Drinking Water

Feet: 0, 2,000, 4,000, 8,000

Meters: 0, 1,000, 2,000

N

Figure 17.3

Baseline Water Quality Quarterly Sampled Wells

Dewey-Burdock Project

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Table 17.2: Quarterly Sampled Groundwater Quality Well Data

Hydro ID	Twn (N)	Rng (E)	Sec	Qtr Qtr	Easting[1]	Northing[1]	Screened Location[2]	Well Use
2	7	1	16	SESE	1026724	423922	Chilson	Domestic
5	7	1	14	NENW	1035181	427284	Fall River	Stock
7	7	1	23	NWNW	1033304	422417	Fall River	Domestic
8	7	1	23	SWSE	1036052	418515	Fall River	Domestic
13	7	1	3	NWNW	1028360	438470	Chilson	Domestic
16	7	1	1	NESW	1041428	434446	Chilson	Domestic
18	7	1	9	SWSW	1022812	428960	Fall River	Domestic
42	7	1	5	SWNE	1021144	436481	Chilson	Domestic
619	7	1	2	SENW	1034866	436729	Chilson	Stock
628	6	1	20	SESE	1022496	449718	Fall River	Stock
631	6	1	26	SWSW	1034177	449309	Fall River	Stock
650	7	1	1	SESE	1043781	433331	Chilson	Stock
675	7	2	31	SWSE	1046941	406352	Alluvium	Monitor
676	6	1	34	SESW	1030846	439891	Alluvium	Monitor
677	7	1	4	SWSW	1023527	434077	Alluvium	Monitor
678	7	1	9	SWNE	1026522	431925	Alluvium	Monitor
679	6	1	27	NWSE	1032294	446245	Alluvium	Monitor
4002	6	1	30	NWSW	1013414	446931	Inyan Kara	Domestic
7002	7	1	23	NWNW	1033333	421931	Chilson	Stock

Notes: [1] Coordinate system is NAD 27 South Dakota State Plane South.
[2] Inyan Kara indicates that screened interval includes both Chilson and Fall River.

baseline sampling of these wells was conducted quarterly, generally from the 3rd Quarter 2007 through the 2nd Quarter 2008.

Following consultation with DENR, Powertech sampled 14 additional wells on a monthly basis (Figure 17.4, Table 17.3). Of these 14 wells, 6 wells are in the Dewey area, 6 wells are in the Burdock area and 2 wells are north of the project area. The goal of the monthly sampling program was to select wells upgradient, within, and downgradient of the proposed ISR activities.

Figure 17.5 depicts the location of the wells in relation to proposed ISR activities. As part of the 2008 pumping tests, one water quality sample was collected from 10 additional wells (49, 682, 684, 685, 686, 687, 690, 691, 692 and 693 in Table 17.4). One sample also was collected from two new Unkpapa domestic wells (703 and 704 in Table 17.4). One sample also was collected from well 704 after it was completed in the Chilson.

Groundwater samples were analyzed for a constituent list developed based on NUREG-1569 groundwater parameters (NRC, 2003), Regulatory Guide 4.14 parameters (NRC, 1980b), and added parameters from a constituent-list review with DENR.

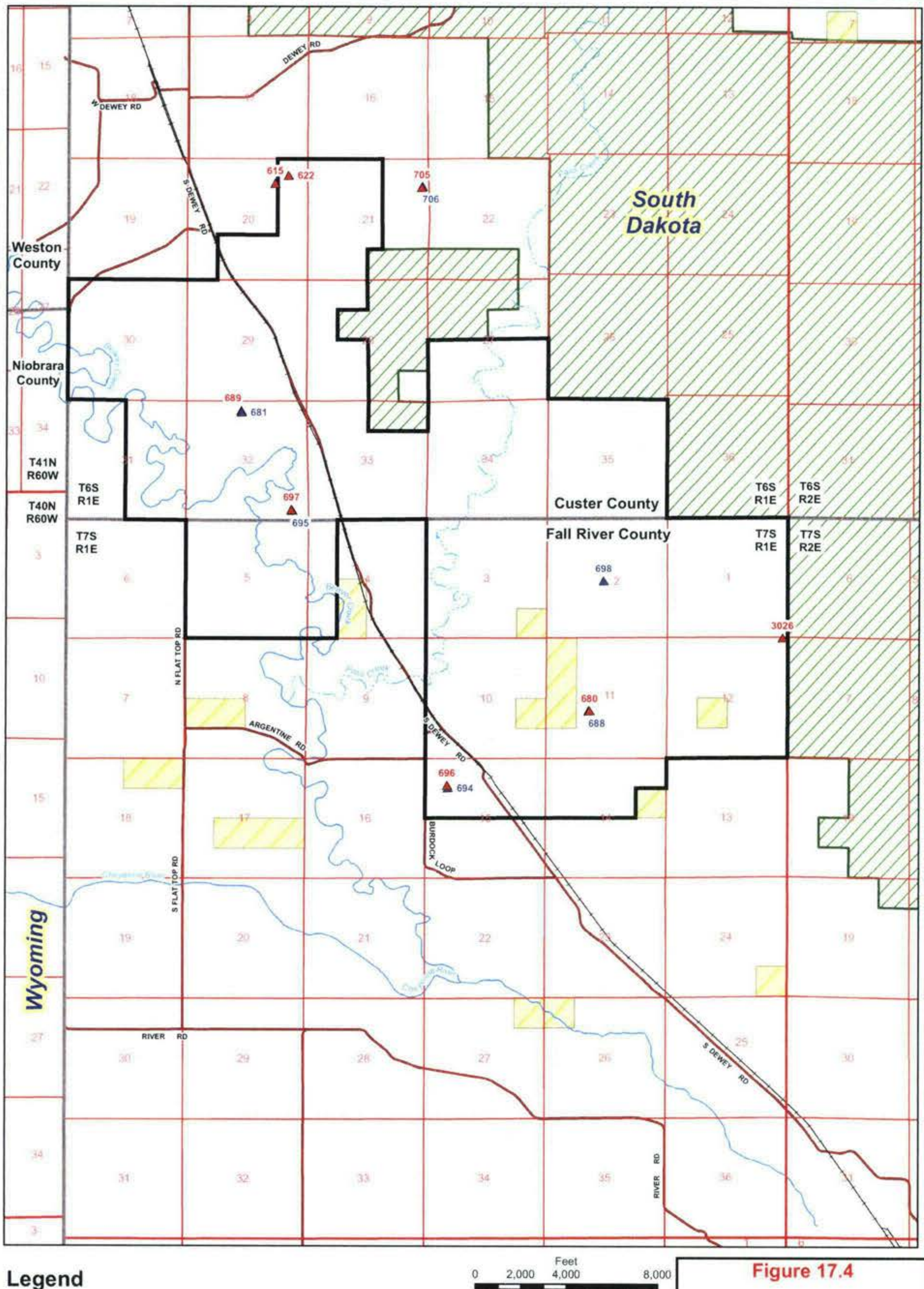
17.7.2 Groundwater Quality Sampling Results

Water quality summary tables providing groundwater quality results for all aquifers are provided in Appendix N, and analytical data are provided in Appendix O.

Consistent with NRC guidance in Section 2.7.4 of NUREG-1569 (NRC, 2003), groundwater and surface water analytical data are presented in tables on a date-by-date, parameter-by-parameter, and well-by-well basis. The following describes the presentation of data in Appendix N.

All field-measured parameters, including water level elevations for groundwater sampling locations, are presented with the corresponding laboratory data. For concentrations reported as non-detect by the laboratory, the data are reported as "< RL" where RL is the laboratory reporting limit. The summary tables present the minimum, maximum and mean concentrations for each parameter at each sample location. Means were calculated using a value of ½ of the RL when non-detect data occurred. Maximum values were calculated as the highest detected value for each constituent at each well, even where a detected concentration is lower than a previous RL.

Groundwater quality summary tables are provided at the beginning of Appendix N describing the mean, standard deviation, minimum, and maximum values for each constituent in the four zones monitored. The monitored zones, in descending order, are the alluvium, Fall River Formation,



Legend

- Permitt Boundary
- BNSF Railroad
- County Roads
- Ephemeral Streams
- Perennial Streams
- BLM Land
- Black Hills National Forest

Aquifer

- ▲ Fall River Monitor Well
- ▲ Chilson Monitor Well

Feet: 0 2,000 4,000 8,000

Meters: 0 1,000 2,000

N

Figure 17.4

Baseline Water Quality Monthly Sampled Wells

Dewey-Burdock Project

DRAWN BY	Mays, Hetrick
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POWERTECH (USA) INC.

Table 17.3: Monthly Sampled Groundwater Quality Well Data

Hydro ID	Twn (N)	Rng (E)	Sec	Qtr Qtr	Easting[1]	Northing[1]	Screened Location	Well Use
615	6	1	20	NWNE	1022172	453708	Chilson	Monitor
622	6	1	20	NENE	1022776	454033	Chilson	Monitor
680	7	1	11	NESW	1035078	429969	Chilson	Monitor
681	6	1	32	NENW	1020330	443725	Fall River	Monitor
688	7	1	11	NESW	1035027	429974	Fall River	Monitor
689	6	1	32	NENW	1020316	443789	Chilson	Monitor
694	7	1	15	NWNW	1028717	426836	Fall River	Monitor
695	6	1	32	SESE	1022385	439312	Fall River	Monitor
696	7	1	15	NWNW	1028538	427141	Chilson	Monitor
697	6	1	32	SESE	1022350	439347	Chilson	Monitor
698	7	1	2	NESW	1035909	435651	Fall River	Monitor
705	6	1	21	NENE	1028624	453314	Chilson	Monitor
706	6	1	21	NENE	1028589	453276	Fall River	Monitor
3026	7	1	12	NENE	1043638	432833	Chilson	Monitor

Note: [1] Coordinate system is NAD 27 South Dakota State Plane South.

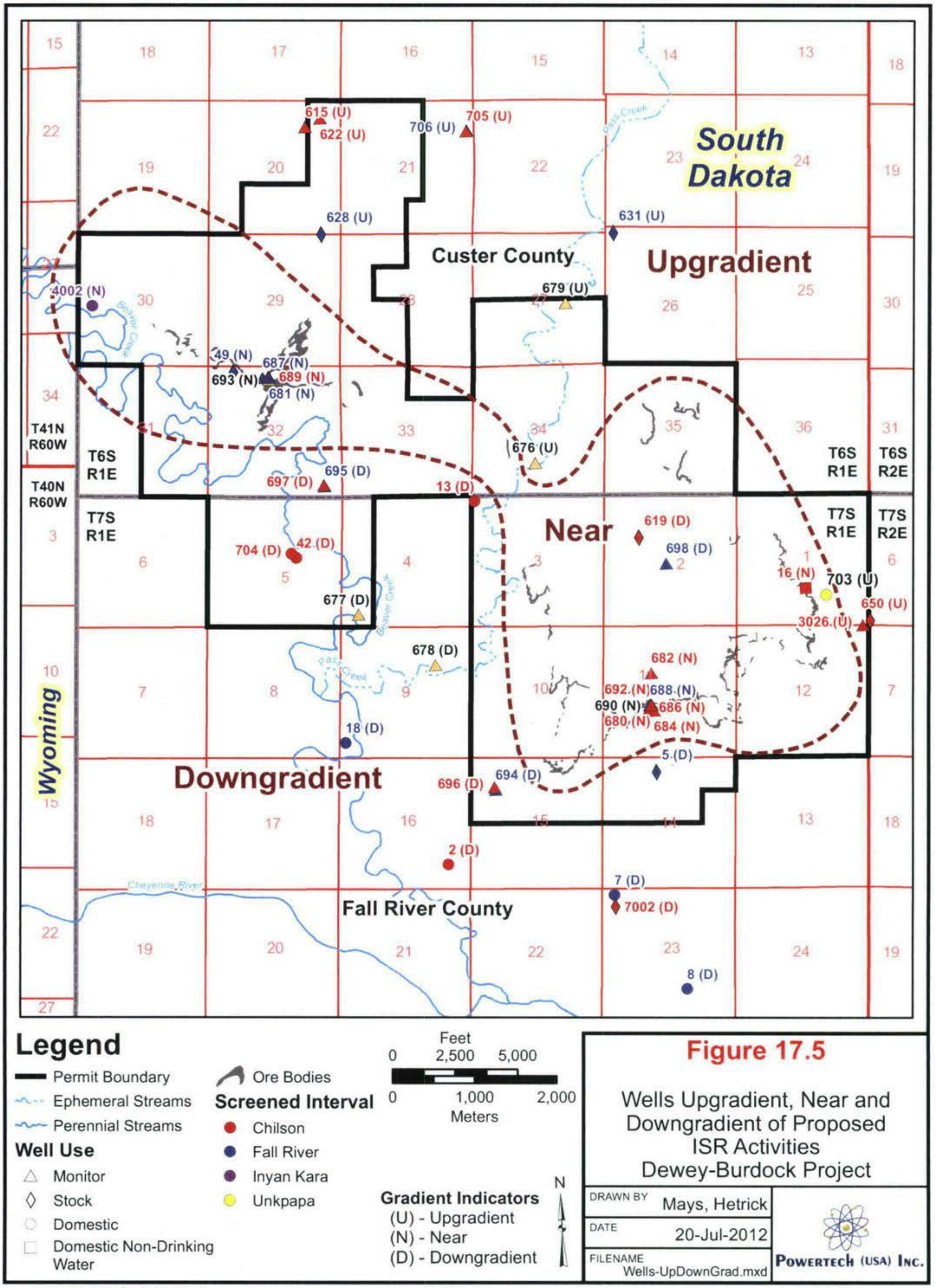

Figure 17.5

Wells Upgradient, Near and Downgradient of Proposed ISR Activities Dewey-Burdock Project

Table 17.4: Additional Well Data

Hydro ID	Twn (N)	Rng (E)	Sec	Qtr Qtr	Easting[1]	Northing[1]	Screened Location	Well Use
49	6	1	32	NWNW	1018932	444022	Fall River	Stock
682	7	1	11	SENW	1035139	431257	Chilson	Monitor
684	7	1	11	NESW	1035191	429744	Chilson	Monitor
685	6	1	32	NWNE	1020690	443409	Fall River	Monitor
686	7	1	11	NESW	1034970	429749	Chilson	Monitor
687	6	1	32	NENW	1020081	443724	Fall River	Monitor
690	7	1	11	NESW	1035114	429970	Unkpapa	Monitor
691	6	1	32	NENW	1020364	443698	Fall River	Monitor
692	7	1	11	NESW	1035075	430014	Chilson	Monitor
693	6	1	32	NENW	1020327	443661	Unkpapa	Monitor
703	7	1	1	SWSE	1041621	434334	Unkpapa	Domestic
704	7	1	5	SWNE	1020966	436647	Unkpapa/Chilson[2]	Domestic

Notes: [1] Coordinate system is NAD 27 South Dakota State Plane South.
[2] Well was originally completed in the Unkpapa and later in the Chilson.

Chilson Member of the Lakota Formation, and Unkpapa Sandstone. Only the results of the Fall River and Chilson, the primary focus of this Class III UIC application, are discussed below. Refer to Powertech (2011) for additional description of sample results including relationships between dissolved, suspended, and total fractions of various constituents.

Fall River Formation Sample Results

Table 17.5 provides a summary of the water quality within the Fall River and Chilson. The ranges shown represent the range of the average concentrations for the wells in each monitoring zone. They do not represent the minimum and maximum absolute sample concentrations for any one well. Table 17.6 summarizes the major ion chemistry of the Fall River wells. The water quality in the Fall River Formation is characterized by moderate TDS (774 to 2,250 mg/L), relatively consistent major ion chemistry, and high radionuclide concentrations. Sodium is the dominant cation in 75% of wells (9 of 12). Of the remaining three wells, two exhibited calcium dominance and one well did not have a dominant cation (i.e., all less than 50%). All of the Fall River baseline wells exhibited strong sulfate dominance, with sulfate accounting for 73% to 92% of the anion concentration (in meq/L). While many of the Fall River Formation baseline wells were outside of the ore zone and yielded low to non-detectable radionuclide concentrations, the maximum radionuclide concentrations in the Fall River Formation were often relatively high. For example, the highest average gross alpha concentration (dissolved) was 1,505 pCi/L in well 698, and the highest average radon-222 concentration was 278,030 pCi/L in well 681.

Chilson Sample Results

The water quality in the Chilson Member of the Lakota Formation is characterized by moderate TDS (708 to 2,358 mg/L), relatively consistent major ion chemistry, and often high radionuclide concentrations. Table 17.7 summarizes the major ion chemistry of the Chilson wells. Sodium is the dominant cation in 53% of wells (8 of 15). Four wells (27%) exhibited calcium dominance and three wells (20%) did not have a dominant cation. All of the Chilson baseline wells exhibited strong sulfate dominance, with sulfate accounting for 71% to 92% of the anion concentration (in meq/L). Many of the Chilson baseline wells yielded relatively high radionuclide concentrations. For example, the highest average gross alpha concentration (dissolved) was 4,991 pCi/L in well 680, and the highest average radon-222 concentration was 180,750 pCi/L in well 42.

17.7.3 Comparison with Drinking Water Standards

Table 17.8 compares the Fall River and Chilson groundwater sample results with EPA MCLs and one secondary standard (sulfate). The table shows that most of the Inyan Kara wells exceeded the gross alpha and radium-226 MCLs in one or more samples, and some of the wells

Table 17.5: Summary of Water Quality by Formation

Constituent	Units	Fall River	Chilson
Field Parameters			
Water Level Elevation	ft AMSL	3,574.6 - 3,725.1	3,647.9 - 3,709.7
Field Temperature	°C	11.1 - 14.9	9.4 - 15.4
Field pH	s.u.	6.7 - 8.4	6.9 - 8.3
Field Dissolved Oxygen	mg/L	0.07 - 5.4	0.1 - 3.3
Field Conductivity	umhos/cm	1,223 - 2,623	958 - 2,750
Field Turbidity	NTU	0.1 - 13.1	0.4 - 29.3
Physical Properties			
Conductivity @ 25°C	umhos/cm	1,201 - 2,870	1,055 - 2,688
Oxidation-Reduction Potential	mV	129 - 258	32 - 236
pH	s.u.	7.1 - 8.5	7.1 - 8.1
Sodium Adsorption Ratio (SAR)	unitless	1.0 - 11.4	0.9 - 10.2
Solids, Total Dissolved TDS @ 180 C	mg/L	774 - 2,250	708 - 2,358
Common Elements and Ions			
Alkalinity, Total as $CaCO_3$	mg/L	117 - 197	71 - 261
Carbonate as CO3	mg/L	<5 - 7.9	<5 - 3.1
Bicarbonate as HCO_3	mg/L	143 - 240	87 - 318
Calcium	mg/L	30 - 368	35 - 386
Chloride	mg/L	9.5 - 47	5.0 - 17.5
Fluoride	mg/L	0.3 - 0.5	0.1 - 0.6
Magnesium	mg/L	10.5 - 134	11.8 - 124
Nitrogen, Ammonia as N	mg/L	<0.1 - 0.4	<0.1 - 0.6
Nitrogen, Nitrate as N	mg/L	<0.1 - 0.06	<0.1 - 0.08
Nitrogen, Nitrite as N	mg/L	<0.1	<0.1 - 0.15
Potassium	mg/L	7.1 - 16	7.2 - 21
Sodium	mg/L	87 - 503	47 - 283
Sulfate	mg/L	425 - 1,443	389 - 1,509
Silica	mg/L	5.2 - 11.2	1.2 - 8.6
Metals - Dissolved			
Aluminum	mg/L	<0.1	<0.1 - 0.19
Arsenic	mg/L	<0.001 - 0.002	<0.01 - 0.016
Barium	mg/L	<0.1	<0.1
Boron	mg/L	<0.1 - 0.43	<0.1 - 0.15
Cadmium	mg/L	<0.005 - <0.01	<0.005 - <0.01
Chromium	mg/L	<0.05	<0.05
Copper	mg/L	<0.01	<0.01 - 0.025
Iron	mg/L	<0.03 - 2.58	<0.03 - 6.2
Lead	mg/L	<0.001 - 0.0011	<0.001 - 0028
Manganese	mg/L	0.03 - 2.41	0.04 - 1.5
Mercury	mg/L	<0.001	<0.001
Molybdenum	mg/L	<0.1	<0.1 - 0.067
Nickel	mg/L	<0.05 - 0.03	<0.05 - 0.024
Selenium	mg/L	<0.001 - 0.0014	<0.001 - 0.0014
Silver	mg/L	<0.005 - <0.01	<0.005 - <0.01

Table 17.5: Summary of Water Quality by Formation (cont'd)

Constituent	Units	Fall River	Chilson
Metals - Dissolved			
Thorium-232	mg/L	<0.005	<0.005
Uranium	mg/L	<0.0003 - 0.11	<0.0003 - 0.034
Vanadium	mg/L	<0.1 - 0.06	<0.1 - 0.05
Zinc	mg/L	<0.01 - 0.0125	<0.01 - 0.06
Metals - Dissolved - Speciated			
Selenium-IV	mg/L	<0.001 - 0.0007	<0.001 - 0.0005
Selenium-VI	mg/L	<0.001 - 0.0007	<0.001 - 0.0010
Metals - Suspended			
Uranium	mg/L	<0.0003 - 0.0031	<0.0003 - 0.0014
Metals - Total			
Antimony	mg/L	<0.003	<0.003 - 0.002
Arsenic	mg/L	0.0008 - 0.0038	0.001 - 0.023
Barium	mg/L	<0.1	<0.1 - 0.067
Beryllium	mg/L	<0.001 - <0.005	<0.001 - 0.0005
Boron	mg/L	<0.1 - 0.45	<0.001 - 0.17
Cadmium	mg/L	<0.005	<0.005
Chromium	mg/L	<0.05	<0.05
Copper	mg/L	<0.01	<0.01 - 0.043
Iron	mg/L	0.04 - 4.8	0.08 - 15.3
Lead	mg/L	<0.001 - 0.002	<0.001 - 0.026
Manganese	mg/L	0.03 - 2.49	0.04 - 1.74
Mercury	mg/L	<0.001	<0.001
Molybdenum	mg/L	<0.01 - 0.03	<0.01 - 0.075
Nickel	mg/L	<0.05	<0.05
Selenium	mg/L	<0.001 - 0.001	<0.001 - 0.0019
Silver	mg/L	<0.005 - <0.02	<0.005 - <0.02
Strontium	mg/L	0.65 - 6.2	0.7 - 7.5
Thallium	mg/L	<0.001	<0.001 - 0.0006
Uranium	mg/L	<0.0003 - 0.11	<0.0003 - 0.02
Zinc	mg/L	<0.01 - 0.01	<0.01 - 0.13
Radionuclides - Dissolved			
Gross Alpha	pCi/L	5.6 - 1,505	3.6 - 4,991
Gross Beta	pCi/L	3.2 - 484	7.8 - 1,629
Gross Gamma	pCi/L	216 - 4,994	70 - 15,530
Lead-210	pCi/L	-1.9 - 29.7	-5.6 - 19.3
Polonium-210	pCi/L	0.02 - 2.36	0.02 - 2.03
Radium-226	pCi/L	1.2 - 388	1.2 - 1,289
Thorium-230	pCi/L	0.01 - 0.13	0.04 - 0.20
Radionuclides - Suspended			
Lead-210	pCi/L	-1.5 - 11.8	-1.65 - 22.1
Polonium-210	pCi/L	0.03 - 2.2	0.02 - 4.1
Radium-226	pCi/L	-0.2 - 7.9	-0.15 - 6.3
Thorium-230	pCi/L	-0.07 - 1.29	-0.14 - 0.3

Table 17.5: Summary of Water Quality by Formation (cont'd)

Constituent	Units	Fall River	Chilson
Radionuclides - Total			
Lead-210	pCi/L	<1	<1 - 57
Polonium-210	pCi/L	<1 - 6.4	<1 - 13
Radium-226	pCi/L	<0.2 - 15.2	1.1 - 120
Radon-222	pCi/L	277 - 278,030	197 - 180,750
Thorium-230	pCi/L	<0.2	<0.2

Table 17.6: Fall River Formation Major Ion Chemistry

Major Cations							
Hydro ID	Calcium		Magnesium		Sodium		Dominant Cation
	meq/L	%	meq/L	%	meq/L	%	
5	6.2	19%	4.1	13%	21.9	68%	sodium
7	1.8	12%	1.2	8%	11.9	80%	sodium
8	2.7	19%	1.9	14%	9.6	67%	sodium
18	1.7	12%	1.0	7%	12.0	82%	sodium
628	2.0	11%	1.4	8%	13.9	81%	sodium
631	15.9	58%	7.5	27%	4.0	15%	calcium
681	3.1	22%	2.0	14%	9.2	64%	sodium
688	2.3	19%	1.6	13%	8.3	68%	sodium
694	1.5	10%	0.9	6%	12.3	84%	sodium
695	3.8	23%	2.2	13%	10.5	64%	sodium
698	18.4	55%	11.0	33%	3.8	11%	calcium
706	8.3	47%	3.9	22%	5.6	31%	not any
Major Anions							
Hydro ID	Bicarbonate		Chloride		Sulfate		Dominant Anion
	meq/L	%	meq/L	meq/L	%	meq/L	
5	2.4	7%	0.7	2%	30.1	91%	sulfate
7	3.4	22%	0.3	2%	11.6	76%	sulfate
8	3.4	23%	0.3	2%	11.0	75%	sulfate
18	3.6	25%	0.4	3%	10.7	73%	sulfate
628	3.0	16%	1.3	7%	14.7	77%	sulfate
631	3.3	11%	0.3	1%	25.8	88%	sulfate
681	3.5	25%	0.4	3%	10.1	72%	sulfate
688	2.7	23%	0.3	3%	8.9	75%	sulfate
694	3.6	26%	0.4	3%	10.1	72%	sulfate
695	3.5	22%	0.3	2%	12.1	76%	sulfate
698	2.3	8%	0.3	1%	28.5	92%	sulfate
706	3.9	21%	0.3	1%	14.1	77%	sulfate

Note: Concentrations in milliequivalents per liter represent the average concentration for each well.

Table 17.7: Chilson Member of the Lakota Formation Major Ion Chemistry

Major Cations							
Hydro	Calcium		Magnesium		Sodium		Dominant Cation
ID	meq/L	%	meq/L	%	meq/L	%	
2	2.6	16%	1.4	9%	12.3	75%	sodium
13	3.1	24%	2.0	16%	7.6	60%	sodium
16	5.9	50%	3.8	32%	2.1	18%	calcium
42	1.7	12%	1.0	7%	11.6	81%	sodium
615	3.7	33%	1.8	16%	5.8	51%	sodium
619	16.0	55%	9.4	32%	3.8	13%	calcium
622	4.1	29%	2.4	17%	7.7	54%	sodium
650	8.3	41%	6.5	32%	5.3	26%	not any
680	19.2	54%	10.2	29%	6.0	17%	calcium
689	2.3	21%	1.3	12%	7.7	68%	sodium
696	4.9	31%	3.0	19%	7.7	49%	not any
697	2.6	20%	1.4	11%	9.2	70%	sodium
705	4.2	30%	2.6	18%	7.1	51%	sodium
3026	19.0	52%	9.3	26%	8.2	22%	calcium
7002	11.5	44%	7.3	28%	7.6	29%	not any
Major Anions							
Hydro	**Bicarbonate**		**Chloride**		**Sulfate**		**Dominant Anion**
ID	**meq/L**	**%**	**meq/L**	**meq/L**	**%**	**meq/L**	
2	4.2	25%	0.3	2%	12.4	73%	sulfate
13	3.2	23%	0.3	2%	10.0	74%	sulfate
16	3.1	24%	0.1	1%	9.4	74%	sulfate
42	3.6	25%	0.3	2%	10.3	72%	sulfate
615	2.8	25%	0.1	1%	8.2	74%	sulfate
619	2.3	8%	0.3	1%	26.9	91%	sulfate
622	3.5	25%	0.3	2%	10.2	73%	sulfate
650	1.4	6%	0.5	2%	20.6	92%	sulfate
680	5.0	15%	0.4	1%	28.2	84%	sulfate
689	3.0	27%	0.1	1%	8.1	72%	sulfate
696	4.0	27%	0.3	2%	10.7	71%	sulfate
697	3.3	26%	0.2	2%	9.4	72%	sulfate
705	2.7	19%	0.2	2%	11.1	79%	sulfate
3026	3.5	10%	0.5	1%	31.4	89%	sulfate
7002	5.2	19%	0.3	1%	22.4	80%	sulfate

Note: Concentrations in milliequivalents per liter represent the average concentration for each well.

Table 17.8: Groundwater Quality Comparison with Federal Drinking Water Standards

Parameter	Arsenic, Dissolved	Gross Alpha, Dissolved	Radium-226, Dissolved	Uranium, Dissolved	Sulfate
MCL	0.010 mg/L	15 pCi/L	5 pCi/L*	0.030 mg/L	250 mg/L**
Fall River Wells					
Hydro ID					
5	---	---	---	---	X
7	---	X	X	---	X
8	---	---	---	---	X
18	---	X	X	---	X
628	---	X	X	---	X
631	---	X	X	---	X
681	---	X	X	---	X
688	---	X	X	---	X
694	---	X	---	---	X
695	---	X	X	---	X
698	---	X	X	X	X
706	---	X	---	---	X
Percentage exceeding MCL in one or more samples:	0% (0/12)	83% (10/12)	67% (8/12)	8% (1/12)	100% (12/12)
Chilson Wells					
Hydro ID					
2	---	---	---	---	X
13	---	X	---	---	X
16	---	X	X	---	X
42	---	X	X	X	X
615	X	X	X	---	X
619	---	X	X	---	X
622	---	X	X	---	X
650	---	---	---	---	X
680	X	X	X	X	X
689	---	X	X	---	X
696	---	X	---	---	X
697	---	X	X	---	X
705	---	---	---	---	X
3026	X	X	X	---	X
7002	---	X	X	---	X
Percentage exceeding MCL in one or more samples:	20% (3/15)	80% (12/15)	67% (10/15)	13% (2/15)	100% (15/15)

Notes: **X** denotes that one or more analyses exceed the MCL.

* MCL applies to radium-226 and radium-228 combined.

** Secondary drinking water standard.

exceeded the arsenic and uranium MCLs in one or more samples. Table 17.8 notes that the radium MCL applies to radium-226 and 228 combined. Powertech had some of the earlier samples analyzed for radium-226 and 228 and determined that the concentration of radium-228 was insignificant (see Appendix N). Therefore, radium-228 was not measured in subsequent samples. Table 17.8 compares the sample results for radium-226 with the combined radium-226 and 228 MCL. The groundwater quality summary tables in Appendix N highlight sample results that exceeded EPA secondary standards. Secondary standards exceeded in one or more Inyan Kara water samples include aluminium, iron, manganese, pH, sulfate and TDS. Table 17.8 shows that all of the Fall River and Chilson wells exceeded the secondary sulfate standard.

Table 17.5 shows that the radon-222 concentration was up to 278,030 pCi/L in the Fall River and up to 180,750 pCi/L in the Chilson. These values are 600 to 900 times greater than the ARSD 74:54:01:04 South Dakota drinking water standard of 300 pCi/L, which is the same as the previously proposed federal radon-222 MCL. Appendix N compares sample results with primary and secondary drinking water standards for all sample results from each well.

17.8 Future Operations

With future exploration drilling, there is the potential of locating additional recoverable resources within the project area that are outside the currently requested AEB. A future amendment for a modified AEB might be requested by Powertech if additional potential well field areas are delineated.

18.0 ATTACHMENT U - DESCRIPTION OF BUSINESS

The Class III UIC permit application is submitted by Powertech (USA) Inc. or Powertech, which is the U.S.-based wholly owned subsidiary of the Powertech Uranium Corporation, a corporation registered in British Columbia. Powertech Uranium Corporation shares are publicly traded on the Toronto Stock Exchange as PWE and the Frankfurt Stock Exchange as P8A. Powertech Uranium Corporation owns 100 percent of the shares of Powertech. The corporate office of Powertech Uranium Corporation is located in Vancouver, British Columbia. Powertech is a U.S.-based corporation incorporated in the State of South Dakota.

The addresses and telephone numbers for the general office (Colorado), the New Mexico office and the local office (South Dakota) of the applicant are listed as follows:

COLORADO Powertech (USA) Inc. 5575 DTC Parkway, Suite 140 Greenwood Village, CO 80111	SOUTH DAKOTA Powertech (USA) Inc. 310 2nd Avenue P.O. Box 812 Edgemont, SD 57735	NEW MEXICO Powertech (USA) Inc. 8910 Adams Street NE Albuquerque, NM 87113

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