Underground Injection Control Program

AREA PERMIT

Class III In-Situ Production of Borate
Permit No. R9UIC-CA3-FY19-1

5E Boron Americas Project
San Bernardino County, California

Issued to:

5E Boron Americas, LLC
9329 Mariposa Rd, Ste 210
Hesperia, CA 92344

Draft Permit Modification

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GLOSSARY OF TERMS

Abbreviations	Definition
AOR	Area of Review
AL	Alert Level
APBL	American Pacific Borate & Lithium
AWWA	American Water Works Association
BA	Boric Acid
bgs	below ground surface
BLM	US Bureau of Land Management
BOP	Blowout Preventer
CAP	Corrective action plan
CBL	Cement bond log
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
cm/sec	centimeters per second
CVW	Closure verification monitoring wells
CPVC	Chlorinated Polyvinyl Chloride
Duval	Duval Corporation (original Project corporation)
EPA	Environmental Protection Agency
FACE	Financial Assurance Cost Estimate
FCCC	Fort Cady California Corporation
FCMC	Fort Cady Mineral Corporation
FRP	Fiberglass reinforced plastic
ft	foot or feet
gpm	gallons per minute
GR	Gamma ray
GWQLs	Groundwater quality limits
HCL	Hydrochloric acid
HDPE	High Density Polyethylene plastic
ISR	In Situ Recovery
LOM	life of mine
MCL	Maximum Contaminant Level
mD	millidarcies
Mining Group	Grouping of 35 to 40 injection/recovery (production) wells
MGA	McGinley & Associates
MW	Monitoring Well
MIT	Mechanical integrity test
Mt.	Million tons
NAD 83	North American Datum 83; a unified horizontal or geometric datum providing special reference for mapping purposes
NEPA	National Environmental Policy Act
OW	Observation Well
P&A	Plugging and abandonment
pH	a numeric scale to specify the acidity or alkalinity of an aqueous solution
PLS	Pregnant leach solution
ppb	parts per billion
psi	pounds per square inch of pressure
PVC	Polyvinyl chloride

QA	Quality Assurance
REC (Plan)	Reclamation (Plan)
RVWs	Rinse verification monitoring wells
RWQCB	Regional Water Quality Control Board
SC	Specific conductance
SCE ROW	Southern California Edison Right-of-way
SDWA	Safe Drinking Water Act
SMARA	State (of California) Mining and Reclamation Act
SoP	Sulphate of Potash
SG	Specific Gravity
SWiPs	Standard Wireline Packer System
SX	Solvent Extraction
TDS	Total Dissolved Solids
Tpy	Tons per year
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
µg/L	micrograms per liter
µg/m3	micrograms per cubic meter
UTM	Universal Transverse Mercator Coordinate system for mapping
XRD	x-ray Diffraction (analysis)
VOC	Volatile organic compound
ZEI	Zone of Endangering Influence

PART I. AUTHORIZATION TO CONSTRUCT AND INJECT

Pursuant to the Underground Injection Control regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, 147, and 148,

5E Boron Americas, LLC
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is hereby authorized, contingent upon Permit conditions, to construct and operate a Class III injection well facility and engage in in-situ borate recovery (ISR) operations at the 5E Boron Americas Project (Project). The Project is in Township 8 North, Range 5 East, portions of Sections 25, 26, 27 and 36 in San Bernardino County, California, approximately 17 miles east of Newberry Springs, California as depicted in Figure 1 in Appendix A. The location is two and one-half (2.5) miles south of I-40 and the Burlington Northern Santa Fe Railway Pisgah siding in the Mojave Desert. The Project is expected to operate over a 25-year period. Mine operations will be implemented in three successive blocks as depicted in Figure A-1 of Appendix A.

The Project will encompass an Area of Review (AOR) of approximately 1346.5 acres, with a wellfield and ore~~-~~body extent of approximately 412 acres as depicted in Figure A-1 in Appendix A. The approximate areal dimensions of the ore~~-~~body are 7,205 feet by 3,182 feet as depicted in Figure A-2 in Appendix A.

The permit authorizes injection of a dilute hydrochloric, sulfuric and/or carbonic acid solution into the colemanite deposit at depths greater than 1,15~~30~~0 feet below ground level for boric acid recovery in a pregnant leach solution (PLS) and production of borate in a solvent extraction (SX) process at the surface. The ~~colemanite~~ orebody is borate bearing evaporite minerals (dominantly colemanite), interbedded with mudstone averaging 1% or greater boric oxide (B_2O^3) located within a larger sedimentary mudstone and evaporite unit (Unit 3). See the geological description in Figure A-6 in this Permit. The orebody varies in thickness from 200 to ~~160~~500 feet and is located approximately 1,~~330~~ 170 to 1,~~570~~ 660 feet below ground surface (bgs) ~~level~~ at the Project site. The fully developed wellfield will include up to 450 injection and recovery wells interspaced approximately 200 feet apart in an alternating and repeating pattern. The wellfield will be surrounded by at least seven observation wells (OWs) located within the calculated zone of endangering influence (ZEI), which varies in distance from approximately 800 feet to 1,300 feet beyond the perimeter of the wellfield. ~~and orebody, and a~~At least thirteen monitoring wells ~~located~~ are planned within the AOR boundary which is approximately 100 to 275 feet beyond the ZEI, that circumscribe the wellfield. The permit requires installation of at least ~~one~~ four operational OWs within the orebody. Depending upon results gathered from project operations and monitoring, four (4) additional monitoring wells may be located within the AOR in the northwest and southern areas outside the wellfields of Blocks 1 and 3. The wellfield's recovery wells will be used as rinse verification monitoring wells (RVWs) during rinsing operations, with three RVWs in each 35-40 well group used as closure verification monitoring wells (CVWs) during the post-rinse monitoring period. The OWs and monitoring wells surrounding the orebody will be used as water level, specific conductance, and groundwater quality monitoring wells during mining and rinsing operations and as groundwater quality monitoring wells during the post-rinse period. Hydraulic control will be maintained by a 0.5 percent or greater over-extraction of ISR fluids and monitoring for excursions of ISR fluids at the OWs and MWs.

For the permitted wells within the AOR, EPA will issue authorization to drill and construct only after requirements of Financial Responsibility in Part II, Section L of this permit have been met. EPA will grant authorization to inject only after the requirements of Part II, Sections C, D, and E-2 of this permit have been met. Operation of each injection well will be limited to the maximum volume and pressure as stated in this permit. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, 147 and 148 of the Code of Federal Regulations (CFR), which are regulations in effect on the date that this permit is effective.

This permit consists of fifty-one~~forty-five~~ (51~~49~~) pages plus appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by 5E Boron Americas, LLC (the Permittee) and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit.

This permit and the authorization to construct, operate, and inject are issued for a period to include the approximate 25-year Project operation and restoration life and the five (5)-year post-rinse monitoring period, unless terminated under the conditions set forth in Part III, Section B.1 of this permit. This permit and authorization to inject shall also include any additional post-rinse monitoring beyond five (5) years, if deemed necessary by EPA.

This permit is issued on August 13, 2020 and becomes effective on August 13, 2020.

\signed\

Tomás Torres
Water Division Director
EPA Region IX

MODIFICATION TO THIS PERMIT No. R9UIC-CA3-FY19-1

In accordance with 40 CFR §144.39, this Permit for 5E Boron Americas Fort Cady Project is hereby modified to include the following: update of the Table of Contents with updated page numbers; a glossary of terms after the Table of Contents; a change of the word "will" to "shall" where noted; a bottom mining exclusion zone of twenty (20) feet from the bottom of Unit 3; correction to the geologic reference to the orebody with reference to Unit 3 and to the mineable portion referred to as the orebody; additional observation well requirements in Section II.F; increased frequency of groundwater flow model updates; and, correction of typographical errors.

EPA adds the new language in redline/underline and deletes language in redline/struck through with the existing Permit language not in redline. All existing permit language not in redline remain unchanged. The existing Permit language incorporates all prior minor modifications.

This modification is issued on the date signed and becomes effective on _______________.

Tomás Torres
Water Division Director
EPA Region IX

PART II. SPECIFIC PERMIT CONDITIONS

A. REQUIREMENTS PRIOR TO DRILLING, TESTING, CONSTRUCTING, OR OPERATING

1. Financial Assurance

   The Permittee shall supply evidence of financial assurance prior to commencing any well drilling and construction, in accordance with Section L of this part.

2. Field Demonstration Submittal, Notification, and Reporting

   a. Prior to each demonstration or test required in Sections B through E~~D~~ of this permit, the Permittee shall submit plans and specifications for procedures to the EPA Region 9 Groundwater Protection Section for approval. The submittal address is provided in Section G, paragraph 5. No demonstration or test in these sections may proceed without prior written approval from EPA.

   b. The Permittee must notify EPA at least thirty (30) days prior to performing any required field demonstrations or test, after EPA approves the plans/procedures for testing, in order to allow EPA to arrange to witness if so elected.

   c. The Permittee shall submit results of each demonstration or test required in Part II of this permit to EPA within thirty (30) days of completion, unless otherwise noted.

B. PROTECTION OF UNDERGROUND SOURCES OF DRINKING WATER

1. No Migration into or between Underground Sources of Drinking Water (USDWs).

   Pursuant to 40 CFR Parts 144 and 146 and the conditions established herein, during well construction and testing and the approximate twenty five (25)-year operation and restoration life of the 5E Boron Americas ISR Project and five (5)-year post-rinse monitoring period, the Permittee shall ensure that there is no migration of injection fluids, process by-products, or formation fluids that exceed the limits specified in Part II.F of this permit beyond the Area of Review described at Part I and delineated in Figure A-1 in Appendix A of this permit.

2. Adequate Protection of USDWs.

   Pursuant to 40 CFR §§144.12 and 146.10(a)(4), the Permittee shall adequately protect USDWs by commencing, within ninety (90) days after completing borate recovery operations in the Project wellfield, restoration of groundwater in the injection and recovery zones of the wellfield to primary maximum contaminant levels (MCLs) under 40 CFR Part 141, or pre-operational concentrations if those concentrations exceed MCLs, and by subsequently plugging and abandoning the designated wells in the wellfield in accordance with Part II.I.1, Restoration and Plugging & Abandonment Plan, and Appendix C of this permit. Wells converted to post-closure monitoring or closure verification wells (CVWs) and all OWs, RVWs, and monitoring wells (MWs) ~~will~~ shall be plugged and abandoned at the end of the post-closure monitoring period when all CVWs, OWs, and MWs have met groundwater quality limits (GWQLs) for five consecutive years.

C. WELL CONSTRUCTION

1. Location of Project Wells

   a. The Project injection and recovery wells shall be contructed within the designated mining area for each block delineated in Figure A-3 in Appendix A and located in Township 8 North, Range 5 East and portions of Sections 25, 26, 27 and 36 in San Bernardino County, California, (at coordinates 34 degrees, 47 minutes, 7.2 seconds North and 116 degrees, 24 minutes, 1.2 seconds West). The first five proposed injection and recovery well locations are depicted in Figure A-3 in Appendix A. Mining is planned to commence in year one in Block 2, with the completion of five (5) I/R wells and four OWs surrounding the I/R wells within the mining area. The number of wells is expected to increase to 35-40 wells during years two or three. After which, wells will be added as needed. The total number of wells may be increased or decreased during the life of the mine (LOM), depending upon recovery rates. Infrastructure will be developed in sequence with the wellfield and will consist of main trunk lines and branch lines. The Project wellfield will be approximately 412 acres in size, as depicted in Figure A-1. ~~The Project is located near the Pisgah Crater, approximately 17 miles east of Newberry Springs, California as depicted in Figure Intro-1 in Appendix A.~~

   b. After drilling and well construction is completed, the Permittee must submit final well location information, including distances in feet from the closest section lines (metes and bounds) and latitude/longitude coordinates (Geodetic Datums: NAD83 or WGS84) of the wells constructed under this permit, including all observation, and monitoring wells. Monitoring wells include the Area of Review (AOR) wells located within the AOR boundary. The distances and direction of each OW, AOR well, and MW from the closest Project wellfield boundary shall also be provided in the Final Well Construction Report required under paragraph 9(a) of this section. If final well locations differ significantly from the proposed locations described above, justification and documentation of any communication with and approval by EPA shall be included.

2. Logging and Testing during Drilling and Construction

Open-hole geophysical logs shall be run in each well boring for formation evaluation, depth control, and detection of borehole anomalies. Geophysical tools shall include at a minimum caliper, gamma-ray, induction, temperature, directional survey, sonic, and acoustic logs. Electrical logs shall be run in all OWs and MWs. In addition, compensated neutron-density logs or other appropriate logs as approved by EPA in writing are required in at least one injection well boring within each of the well groups to provide a more representative sampling of porosity values throughout the Project area. Porosity values determined from the neutron-density logs or alternative logs approved by EPA shall be compared to porosities applied to the groundwater flow model in the project area, and the porosity values in the model shall be revised accordingly if significant differences are found in the comparison with log porosities.

Cased-hole geophysical logs, including gamma ray, temperature, and/or cement bond logs (CBLs) shall be run in all steel-cased wells over the entire length of each well casing after the steel casing has been installed and cemented in place. Gamma ray (GR) and temperature logs are required in fiberglass reinforced plastic (FRP) cased wells and polyvinyl chloride (PVC) cased wells for determination of the top of cement in the casing/wellbore annulus within 48 hours of cementing the casing if cement is not returned to surface in the annulus or not backfilled with cement to the surface. GR-temperature logs are required to evaluate mechanical integrity of the casing/wellbore annulus 30 to 60 days after injection operations begin. In addition, radioactive tracer surveys may be required in injection wells if temperature logs are negative or inconclusive in the evaluation of Part II mechanical integrity.

Additional geophysical surveys may be conducted as required by EPA. The CBL evaluation will enable the analysis of the bond between the cement and casing, as well as between the casing and formation, and shall allow detection and assessment of any micro-annuli between the casing and cement as well as any cement channeling in the borehole annulus. Refer to Appendix D for information on EPA Region 9 temperature logging guidelines and requirements for evaluation of zonal isolation after injection commences.

3. Drilling, Work-over, and Plugging Procedures and Records

Drilling, work-over, and plugging procedures shall comply with applicable portions of the American Water Works Association (AWWA) standards, unless a section conflicts with UIC permit requirements, and in accordance with 40 CFR §146.32. Drilling, work-over, and plugging procedures for each well or group of similarly constructed wells shall be submitted to EPA for approval. Once approved, a thirty (30)-day notice shall be submitted to EPA for witnessing purposes prior to construction, workover, or plugging of individual or groups of similarly constructed Class III wells. Procedures and records shall include the following:

a. Details for well construction and cementing casing strings and work-overs, and plugging procedures;

b. Records of daily Drilling Reports (electronic and hard copies);

c. Blowout Preventer (BOP) System testing on recorder charts including complete explanatory notes during the test(s), if applicable; and

d. Casing and other tubular and accessory measurement tallies.

Information provided with EPA Form 7520-18, Completion Report for Injection Wells, or EPA Form 7520-19, Well Rework Record, Plugging and Abandonment Plan, or Plugging and Abandonment Affidavit (refer to list in Appendix C) is also acceptable to include in the procedures. The Permittee shall also comply with AWWA standards as stated at Part II.C.3 above for Well Casing and Drilling.

Wells drilled and installed at the Project will include injection, recovery, observation and monitoring wells. Those wells shall be constructed to meet Class III requirements at 40 CFR §146.32. In addition, recovery wells ~~will~~ shall be utilized as RVWs during groundwater restoration operations and as CVWs at selected locations within the inactive mine groups during the post-rinse monitoring period.

The well construction procedures described in Attachment L of the permit application and schematic details submitted in Attachment M of the permit application are hereby incorporated into this permit as Appendix B and are binding on the Permittee. Where any conflict or inconsistency exists between Appendix B and the permit conditions, the permit condition shall supersede the procedure or detail in Appendix B. All wells shall be cased and cemented to prevent the migration of fluids into or between USDWs and contain ISR fluids within the injection zone of each well or integrated group of wells. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well and shall be maintained until the well is plugged and abandoned in accordance with Part II, Section I of this permit.

EPA may require minor alterations to the construction requirements based upon information obtained during well drilling and related operations. Final casing setting depths will be determined by the field conditions, well logs, and other input from the Permittee and EPA staff. EPA approval must be obtained for any revisions of the procedures approved as referenced in Parts II.C.3 and II.C.4 of this permit prior to installation, and these ~~will~~ shall be documented in the Final Well Construction Report (See paragraph 9(a) below).

Boreholes ~~will~~shall be drilled in a single stage to the design total depth after installation of conductor casing. After installing and cementing conductor casing to a depth of up to 300 feet, the well will consist of a boring drilled from land surface to the base of the orebody. The borehole within the bedrock will remain open in most wells. ~~FRP screens will be installed below 40 feet from the top of the orebody.~~ FRP screens shall be installed within the orebody at least 40 feet below the top of Unit 3 and at least 20 feet above the bottom of Unit 3 (See Figure A-6 for defined geology units).

Casing materials to be used include FRP, PVC, and/or steel, as depicted in Figures M-2, M-3, and M-4 in Appendix B. Casing centralizers ~~will~~ shall be placed at 40-foot intervals along the FRP or PVC casing and screen length.

4. Cementing

Casing in all wells ~~will~~ shall be cemented from a depth of 40 feet below the top of ~~the orebody~~ Unit 3 (minimum) to the surface. The cement ~~will~~ shall be either circulated into the annular space through a cement shoe or cement diverter valve to allow cement to be pumped through the casing and upward through the annulus, or the cement ~~will~~ shall be placed in the annular space between the borehole and casing from the bottom up to the surface using a tremie method. If cementing after the hole is drilled to design depth, the cement ~~will~~ shall be the last step before testing and development. If the solid casing is cemented a minimum of 40 feet into ~~the ore body~~Unit 3 or targeted monitoring zone, then the lower section of the well ~~will~~ shall be drilled from the bottom of the cemented casing to the design depth before the lower casing is installed, as depicted in Figures M-3 and M-4 in Appendix B.

Water and/or appropriate mud-breaker chemicals shall be circulated through the casing prior to cement placement to reduce mud viscosity, assist in removal of mud from the borehole/casing annulus, and promote bonding between the casing, cement, and formation. Cement return shall be observed at the surface prior to terminating the cementing operation. Following placement of the cement slurry, the cement ~~will~~ shall be allowed to cure for a minimum of 24 hours before performing additional operations on the well. The cement shall consist of Type G with an acid resistant cement additive mixed thoroughly and free of lumps and used at a minimum in the bottom 200 feet of the casing. The remainder of the annular space ~~will~~ shall be cemented with Type G via tremie from the top of the acid resistant cement to surface.

5. Monitoring Devices

The Permittee shall install and maintain in good operating condition:

a. Sampling equipment upstream of the injection wellhead for the purpose of obtaining representative samples of injection fluids.

b. Devices to continuously measure and record injection pressure, annulus pressures, flow rates, injection and production volumes, subject to the following:

i. Pressure gauges shall be of a design to provide:

(A) A full pressure range of at least fifty (50) percent greater than the anticipated operating pressure; and

(B) A certified deviation accuracy of five (5) percent or less throughout the operating pressure range.

ii. Flow meters shall measure cumulative volumes and be certified for a deviation accuracy of five (5) percent or less throughout the range of rates allowed by the permit.

c. Conductivity Sensors:

Conductivity sensors (CS) shall be installed in screened intervals of the OWs, MWs, and AOR wells at strategic depths to detect excursions during leaching and rinsing operations and to detect any exceedances of water quality standards during the post-rinse monitoring period. Baseline conductivity and water quality data shall be collected and evaluated before injection commences as specified in Appendix I. Daily specific conductivity measurements shall be recorded by a datalogger.

CS shall be installed in the screened intervals of operational OWs at strategic depths to monitor the movement of mining related solutions and gather data for calibration of the groundwater flow model.

6. Injection Interval

The ~~top~~ upper mining exclusion zone is the forty (40) feet below the top of Unit 3, and the ~~bottom~~ lower mining exclusion zone is the bottom twenty (20) feet of Unit 3. The Permittee shall only inject fluids at depths between the top exclusion zone and the bottom exclusion zone unless the Permittee has received written approval from EPA to expand the injection interval.

~~The Permittee shall only inject fluids at depths greater than forty (40) feet below the top of the orebodyUnit 3 ("exclusion zone") unless the Permittee has received written approval from EPA to expand the injection interval.~~ To ensure that the injection interval is at depths below the ~~top of~~ upper mining exclusion zone and above the ~~bottom~~ lower mining exclusion zone ~~at least forty (40) feet below the top of the orebody~~of Unit 3, the Permittee shall case and cement all injection wells in a manner described at Part II, Sections C.4 and C.5 of this permit from the surface to at least forty (40) feet below the top of ~~the orebody~~Unit 3 and at least twenty (20) feet above the bottom of Unit 3. The Permittee ~~will~~ shall develop the injection interval for each well by drilling into the orebody, beyond the bottom of the casing and cemented interval. Well screens in observation, and monitoring wells designed to monitor the orebody production activities shall ~~will~~ be installed ~~through the 1300 ft to 1500 ft interval below the exclusion zone~~ to a depth and interval equivalent to the screened orebody completion intervals in the nearest injection and recovery wells.

7. Injection Formation Testing

Formation testing ~~will~~ shall be performed upon installation of the first five injection and recovery wells and used to determine the injection and recovery rates in each mine group. Proposed formation testing procedures must be submitted to EPA for review and approval in accordance with Part II.A.2 of this permit. Test results shall be reported to EPA in accordance with Part II.G of this permit. Results of the formation tests ~~will~~ shall be compared to parameters used in the groundwater flow model, and the model parameters ~~will~~ shall be revised accordingly if the resulting test parameters are significantly different from those used in the model. The groundwater flow model shall be updated and reevaluated with this revised data along with logging and testing information during drilling and construction in accordance with the schedule in Part II.J of this Permit.

8. Final Well Construction Report and Completion of Construction Notice

a. The Permittee must submit a Final Well Construction Report for all Project wells, including logging and other results, with a schematic diagram and detailed description of construction, including driller's log and materials used (e.g., tubing tally, cement type and amounts, and other materials and amounts) and any changes to the approved construction plans, to EPA within sixty (60) days after completion of all Project wells for the first five injection/recovery wells and a mine group in a Block, including additional injection/recovery (I/R), OWs, and all monitoring wells. Construction details, downhole equipment, depths to key formation tops and the USDW base, if applicable, screened interval depths, and schematics of all Project wells shall be described in the Final Well Construction Report for each mine group.

b. The Permittee shall also submit a notice of completion of construction to EPA (refer to EPA Form 7520-18 listed in Appendix G). Injection operations for a particular well or mine group may not commence until all related Project wells for the Block are completed and operational, all well and formation testing is complete, necessary reports are submitted, and EPA has inspected or otherwise reviewed and approved the construction and other details for the permitted wells and notified the Permittee of EPA's approval.

9. Proposed Changes and Work-overs

A well work-over is any physical alteration or addition to an existing well that results in a change in the composition, diameter, perforations, screen depths, tubing, packer depths, or depth of the well casing or a change in the cement in the outer annulus.

a. The Permittee shall give advance notice to EPA, as soon as possible, of any planned physical alterations or additions to the permitted Project wells. Any changes in well construction that deviate from approved construction parameters defined in Part II.C of this permit shall require prior approval by EPA and may require a permit modification under the requirements of 40 CFR §§144.39 or 144.41.

b. In addition, the Permittee shall provide all records of well work-overs, logging, or other subsequent test data, including required mechanical integrity testing, to EPA within thirty (30) days of completion of the activity.

c. Appendix G contains a list of the appropriate EPA reporting forms for well changes or work-overs.

d. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of work-overs or alterations and prior to resuming injection and recovery activities of the modified well, in accordance with Section E.3 of this part.

D. CORRECTIVE ACTION (PLUGGING AND ABANDONMENT PLAN)

Before injection and recovery wells are placed in service:

EPA may require corrective actions if USDWs exist within the AOR based on logging analysis and testing in wellfield development, observation, and monitoring wells (as described above). EPA may also require additional monitoring and/or plugging/re-plugging wellbores and coreholes if existing wellbores and coreholes lack sufficient casing and cement and/or are not adequately plugged to contain fluids within the permitted injection zone.

All existing non-Class III wells and coreholes within the proposed Project mine group shall be abandoned per the Corrective Action and Plugging and Abandonment Plans (Appendix C of this permit), if not adequately constructed and/or plugged to protect USDWs found within the AOR or to contain ISR fluids in the permitted injection zone. The identification, location, depths, status, and availability of hole summaries and logging information of the wells and coreholes located within the AOR are listed in Table C-1 and depicted in Figure C-2 in Appendix C. The Plugging and Abandonment Plans (EPA Form 7520-19) for each well and corehole within the AOR that requires plugging or re-plugging as a corrective action shall be submitted to EPA for review and approval. EPA shall be notified, and final plugging and abandonment (P&A) plans and procedures shall be submitted to EPA for approval at least thirty (30) days in advance of plugging operations. EPA approval will be provided within thirty (30) days if the P&A plans and procedures are deemed complete and fully acceptable.

E. WELL OPERATION

1. Description of Operations

The Operating Data description, in Attachment H of the permit application, is incorporated into this permit in Appendix E and shall be binding on the Permittee with the following conditions. Where any conflict or inconsistency exists between the Operation Data description and the permit conditions, the permit condition shall supersede the language in the description of Operating Data.

a. Planned injection rates will vary in the mining operations of the three blocks as follows:

During ISR operations, the extraction rate of recovery wells shall not fall below one-hundred and one/half (100.5) percent of the injection rate on a monthly basis without prior written approval of a lower percentage from EPA. During the initial operation of the first five I/R wells in Block 2, the fluid balance between injection and recovery rates may vary from 100.5 percent as the porosity and permeability of the orebody increases and before ISR operations stabilize. The allowable variance is subject to EPA review of testing and approval prior to commencement of ISR operations and subsequent review of monthly ISR operational and monitoring data and approval on a quarterly basis. Long-term net extraction volumes shall be maintained at one/half percent (0.5%) or greater on a monthly basis unless a variance is requested by the permittee and approved by EPA. An inward hydraulic gradient of no less than 0.01 ft./ft. between the AOR/MW well pairs and the closest OW shall be monitored and maintained on a daily average basis. If the inward gradient cannot be maintained at 0.01 ft./ft, the net extraction rate or volume shall be increased to achieve that minimum inward gradient between all MWs/AOR well pairs and the closest OW. Prior to or after commencement of ISR operations, the permittee may request EPA approval for a temporary variance from the 0.01 ft./ft gradient during the operations of the first five I/R wells in Block 2 subject to an absence of exceedances in specific conductance action levels at the monitoring wells. The choice, number, and location of MWs, AOR wells, and OWs to be installed and monitored during mining in the three blocks and rinsing operations shall be subject to EPA review and approval in accordance with Part II, Section F.6.

An inward gradient of at least 0.01 ft./ft. between MW/AOR well pairs, and the closest OW shall be established prior to the commencement of injection of dilute hydrochloric acid solution and maintained for demonstrating hydraulic control unless adjusted by

EPA as described above and in Part II, Section H.1.b. Re-balancing of net extraction volumes to restore hydraulic control of ISR fluids shall be required on a monthly basis.

b. The Permittee may submit an operational and monitoring plan to demonstrate that a longer-term basis is as protective as the monthly flow volume re-balancing. If the Permittee demonstrates that re-balancing on greater than a monthly basis is as effective and protective as monthly re-balancing, EPA will consider the results of that demonstration for a revision to the re-balancing requirement. However, a change to that condition will not be authorized without prior written approval from EPA.

c. The Permittee shall measure specific conductance (SC) in the MWs, AOR wells, and OWs to confirm hydraulic control at appropriate and approved depths in the monitored intervals. SC readings in the OWs shall not significantly exceed baseline conductivity and statistical noise levels, as determined by EPA approved procedures, to confirm hydraulic control.

d. Actions shall be taken to restore hydraulic control within 24 hours of detection that the monthly extraction to injection ratio has fallen below one-hundred and one/half (100.5) percent or the inward gradient at any tri-group of MWs, AOR wells, and OWs is less than 0.01 ft./ft., or the specific conductance data in the MWs, AOR wells, and/or OWs indicate a possible loss of hydraulic control, unless EPA approves a variance from these requirements, as set forth above. Actions shall also be taken on a timely basis to reverse outward ISR fluid movement detected in other monitoring wells, and to contain ISR fluids to the wellfield during recovery, rinsing, and post-rinse monitoring operations.

2. Demonstrations Required Prior to Injection

Injection operations may not commence until construction of all Project wells associated with subject injection operations in a specific mine area or group is complete and the Permittee has complied with the following mechanical integrity requirements.

The Permittee shall demonstrate that the Project wells have and maintain mechanical integrity consistent with 40 CFR §146.8 and with paragraph 3 of Section E. The Permittee shall demonstrate that there are no significant leaks in the casing and tubing, and that there is not significant fluid movement out of the injection zone and/or through the casing/wellbore annulus or vertical channels adjacent to the wellbore. The Permittee may not commence initial injection into the wells, or recommence injection after a work-over which has corrected any loss of well integrity, until the Permittee has received written notice from EPA that the demonstration provided is satisfactory and that injection is authorized.

3. Mechanical Integrity

Pursuant to 40 CFR §144.51(q), all injection and recovery wells, and other Project wells shall maintain mechanical integrity at all times. Pursuant to 40 CFR §146.8, the Permittee shall demonstrate Part I and II mechanical integrity by the following methods and schedule:

a. Methods for Demonstrating Mechanical Integrity

i. Part I: Mechanical Integrity Pursuant to 40 CFR §146.8(a)(l), the Permittee shall demonstrate Part I of the mechanical integrity requirement by the following methods:

(A) Pressure testing

A packer ~~will~~ shall be installed immediately above the proposed injection interval, the wellbore ~~will~~ shall be completely filled with water, and a hydraulic pressure equal to or above the maximum allowable wellhead injection pressure or a lower pressure that has been approved by EPA pursuant to Section II.A.2, but not less than 100 pounds per square inch (psi), ~~will~~ shall be applied to the wellbore annulus. This test shall be for a minimum of thirty (30) minutes. A well shall pass the mechanical integrity test (MIT) if there is less than a five (5) percent decrease/increase in annular and tubing pressure (if tubing is installed for the test) over the thirty (30) minute period. The annular and internal tubing pressures (if tubing is used) shall be monitored and recorded during the test. A well shall not be operated at injection pressures greater than the maximum allowable injection pressure as set forth in Part II, Section E.4 below; or the maximum pressure applied during the test; and

(B) Continuous pressure monitoring

The tubing/casing annulus (if a packer is installed) and injection pressure in active injection wells shall be monitored and recorded continuously by a digital instrument with a resolution of one tenth (0.1) psi.

ii. Part II: Mechanical Integrity - Pursuant to 40 CFR §146.8(a)(2), the Permittee shall demonstrate Part II of the mechanical integrity requirement in all Project wells by the following methods:

(A) A review of the casing and cementing records to verify the absence of potential fluid movement through vertical channels adjacent to the well bore in existing exploratory wells, test wells, and coreholes prior to plugging and abandonment or for conversion to an operational observation well.

(B) Part II mechanical integrity must be demonstrated in new monitoring wells as described below for new Project wells.

(C) A demonstration that the lixiviant and ISR fluids are confined to the proper zone and monitored intervals are hydraulically isolated shall be conducted and submitted for review and subject to approval by EPA. A gamma ray-temperature log and casing caliper log shall be run in all new Project wells 30 to 60 days after injection begins or a loss of external injection well integrity is detected or suspected. Radioactive tracer surveys may be required in injection wells if a temperature log indicates failure of the mechanical integrity evaluation or is inconclusive or a loss of external injection well integrity is detected or suspected. GR- temperature logs shall be run in accordance with EPA Region 9 guidance (in Appendix D), for evaluation of zonal isolation after injection commences in injection wells. Proposed MIT procedures must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the external MIT, providing EPA at least thirty (30) days' notice before the external MIT is conducted.

(D) After installing and cementing the casing, conducting a cement squeeze operation, or any well cement repair, the Permittee shall provide to EPA cementing records and cement evaluation logs that demonstrate isolation of the injection interval. Cement bond logs and temperature logs shall be run in wells with steel casing. Temperature logs shall be run in FRP cased wells. Cementing records and logs shall demonstrate complete filling of the annulus between the borehole wall and well casing with cement and isolation of the injection interval.

Cement evaluation must assess the following four objectives:

1) Bond between casing and cement;

2) Bond between cement and formation;

3) Detection and assessment of any micro-annuli (small gaps between casing and cement); and

4) Identification of any absence of cement and cement channeling in the borehole annulus.

The Permittee shall not commence or recommence well operations until the Permittee has received written notice from EPA that the cement evaluation and demonstration is satisfactory. EPA notice will be provided within thirty (30) days if the evaluation is acceptable and the demonstration is satisfactory.

b. Schedule for Demonstrations of Mechanical Integrity

EPA may require that an MIT be conducted at any time during the permitted life of any well authorized by this permit. The Permittee shall also arrange and conduct MITs per the following requirements:

i. A demonstration of mechanical integrity shall be made within thirty (30) days following the installation of a new Project well. All Project wells shall be pressure tested for mechanical integrity in accordance with paragraph 3.a.i.A of this Section E no less frequently than once every five (5) years. If an injection or recovery well is inactive for two (2) years, a notice of actions and procedures must be provided to EPA that ensures USDWs will not be endangered during the period of temporary abandonment, or the well must be plugged and abandoned. Internal mechanical integrity of injection and recovery wells shall also be demonstrated within thirty (30) days after a work-over is conducted, the construction of the well is modified, or when a loss of mechanical integrity becomes evident during injection operations.

ii. Results of the MITs shall be submitted to EPA in the quarterly reports described in Part II, Section G.2 of this permit.

c. Loss of Mechanical Integrity

The Permittee shall notify EPA, in accordance with Part II, Section G, paragraph 2(h) of this permit, under any of the following circumstances:

i. A well fails to demonstrate mechanical integrity during a test, or

ii. A loss of mechanical integrity becomes evident during operation, or

iii. A significant and anomalous change in the annular or injection pressure and/or rate occurs during normal operating conditions.

Furthermore, for new injection wells, the Permittee shall not commence injection, and for active wells, the Permittee shall terminate injection and may not resume injection until the Permittee has taken necessary actions to restore integrity to the subject well and has demonstrated that the well has integrity as defined at Part II.E.3(a), above.

d. Prohibition without Demonstration

The Permittee shall commence injection into the well after the permit's effective date only if:

i. The well has passed an internal pressure MIT in accordance with paragraph 3.a.i.A of this Section E; and

ii. The Permittee has received written notice from EPA that the internal pressure MIT demonstration is satisfactory.

4. Injection Pressure Limitation

a. Injection wells shall be operated at pressures less than the fracturing pressure of the injection zone. Based on existing field fracture test data at the Project site, a formation fracture pressure gradient of 0.65 psi/foot shall be applied and used to establish maximum hydraulic pressure which may be exerted at the surface until step-rate test data are obtained in the Project wells. The maximum wellhead pressure in each injection well in a group of wells will be based on the lowest measured fracture gradient in each injection well that is tested, and will be calculated based on the depth to the top of the interval receiving the injection fluid and the specific gravity of the injectate, but in no event shall it exceed the calculated pressure that can be safely applied to well equipment. A safety factor of 0.8 shall be applied in the calculation of the maximum allowable surface injection pressure. The maximum allowable surface injection pressure will be established for each injection well on that basis.

In no case shall pressure in the injection zone during injection initiate new fractures or propagate existing fractures in the injection zone or the confining zone. In no case shall injection cause the movement of injectate or formation fluids into a USDW. Injection pressures shall be monitored using a digital instrument and recorded on a daily basis. Injection pressures that exceed the maximum allowable surface injection pressure shall be reduced immediately to a pressure not to exceed the maximum, or the well must be shut in pending correction of an equipment malfunction.

b. The injection pressure limitations in paragraph 4(a) of this Section E may be increased by EPA based on the results of valid step-rate tests or other EPA-approved injectivity tests in the respective proposed injection zone. EPA will determine any allowable increase based upon the step-rate test or other injectivity test results and other parameters reflecting actual injection operations. Step-rate testing shall be performed in accordance with the EPA Region 9 Step-Rate Test Policy, which is included in Appendix H of this permit. Step-rate test and other types of injectivity test procedures shall be submitted for

EPA review and approval at least thirty (30) days in advance of the tests.

c. Should EPA approve an increase in injection pressure limitations per paragraph 4(b) of this Section E, the increased limit shall be made part of this permit by minor modification procedures (40 CFR §144.41).

5. Injection Volume (Rate) Limitation

a. Planned injection rates will vary in mining operations of the three blocks as follows:

The planned initial average daily injection rate for each well is 25 gallons per minute (gpm) and the estimated maximum daily rate is 200 gpm as leaching occurs and permeability increases in the orebody.

During ISR operations, the extraction rate of recovery wells shall not fall below 100.5 percent of the total wellfield injection rate on a monthly average basis without prior written EPA approval. Net extraction volumes shall be maintained at one/half percent (0.5%) or greater, depending on the maintenance of an inward gradient of no less than 0.01 ft./ft. between the three specified MWs, AOR wells, and OWs on a daily average basis. If the inward gradient cannot be maintained at 0.01, the net extraction rate shall be increased to achieve that minimum inward gradient at the three specified MW, AOR well and OW.

b. The Permittee may request an increase in the maximum injection rate or a decrease in the minimum ratio of extraction to injection rate allowed in paragraph 5(a) above. Any such request shall be made in writing and appropriately justified to EPA. Should EPA approve an increase in injection rate limitations, the increased limit shall be made part of this permit by minor modification procedures if the increase is in accordance with requirements at 40 CFR §144.41.

c. Any request for an increase in the injection rate or decrease in the minimum ratio of extraction to injection rate shall demonstrate to the satisfaction of EPA that the increase in volume or reduction in the minimum ratio of extraction to injection rate will not interfere with the operation of the Project or its ability to meet conditions described in this permit, change its well classification, or cause migration of fluids into USDWs and/or beyond the permitted injection zone and Project wellfield AOR boundary.

d. Any proposed injection rate increase shall not cause an exceedance of the injection pressure limitation established under paragraph 4(a) of this Section E.

6. Injectate Fluid Limitations

a. The Permittee shall not inject any solid wastes as defined by 40 CFR Part 261.

b. Injection fluids shall be limited to only fluids authorized by this permit and generated by the Project operation. No fluids shall be accepted from other sources for injection into the permitted wells.

c. Fresh water may be injected to assess the hydraulics of the injection and recovery patterns in the Project wellfield, to assess the performance of related surface facilities, and for rinsing operations.

d. During ISR operations, the injectate solution shall consist of a dilute hydrochloric acid solution (<5 % HCL and 95% recycled process water and/or make-up water) that includes inorganic and organic constituents as defined below. The injectate solution shall have a pH of approximately <0 to 2. Organic compounds in the injectate shall be limited to those listed in Part II F.8(a) of this permit. The average total concentration of total petroleum hydrocarbons (TPH) in the injectate listed in Part II. F.8(a) for each quarter of monthly sampling shall not exceed 10 milligrams per liter (mg/L) unless the permittee demonstrates that a higher TPH concentration would not cause an exceedance in MCLs of specific hydrocarbon contaminants. The permittee may request an increase in the TPH limitation if after six months of sampling lixiviant with a higher TPH concentration, benzene, toluene, ethylbenzene and xylene (BTEX), napthalene, and octane concentrations are consistently below the MCLs. Should EPA approve an increase in the TPH limit, the increased limit shall be made part of this permit by minor modification procedures (40 CFR §144.41).

e. The forecasted composition of ISR process solutions is provided in Table H.1 in Appendix E. Inorganic constituents in the injectate shall be limited to constituents in the hydrochloric acid, lime, or other neutralizing agents used for the purposes described in paragraph 6(f) of this Section E, and to constituents resulting from the interaction of injectate with groundwater and minerals in the oxide zone. Concentrations of inorganic constituents in the injectate shall be subject to the requirements of paragraph 6(g) of this Section E.

f. During rinsing and closure, fresh groundwater may be injected to restore the zone to MCLs or pre-operational background concentrations, whichever are greater. The Permittee may also adjust the pH with lime or other neutralizing agents to aid in the precipitation of soluble metals.

g. At least thirty (30) days prior to commencement of the Project operations, the Permittee shall submit a report for EPA's approval that includes the name and grade of each process chemical that is proposed to be used at the ISR process and that fits in one of the three following categories: (1) organic compounds to be used in the SX process; (2) hydrochloric acid to be used in the SX process or to prepare solutions for injection; or (3) lime or other chemicals to be injected or to be used in ISR solutions. The report shall include the name and grade of each reported chemical, and a Safety Data Sheet (SDS) for each. The report shall also include recommendations, with justifications, as to which constituents of the reported chemicals should or should not be included in the List 1 or List 2 groundwater monitoring program defined at Part II.F.2 and the injectate monitoring program defined at Part II.F.8 of this permit.

h. The Permittee may use a process chemical not included in the reports submitted pursuant to paragraph 6 (g) of this Section E above, provided the Permittee submits a report for EPA's approval at least thirty (30) days prior to the date of the proposed use of the chemical and receives written approval from EPA. Approved changes in process chemicals shall be made part of this permit by minor permit modification procedures (40 CFR §144.41). Reports submitted pursuant to this section during Project operations must include information required by paragraph 6(g) of this Section E.

i. The Permittee shall expand the groundwater monitoring program defined at Part II.F.2 and the injectate monitoring program defined at Part II.F.8 as necessary to conform to EPA's conditions of approval of reports submitted pursuant to paragraphs 6(g) of this Section E.

j. The monitoring and advance notification requirements of Section E.6 and Section F.8 apply only to injectate solution prior to injection and to constituents of process chemicals that may become part of the injectate. The requirements do not apply to PLS that is being re-injected to increase the concentration of boric acid in the PLS before it is delivered to the SX plant for processing.

F. MONITORING PROGRAM

1. Water Quality Monitoring Wells.

The MWs, AOR wells, and OWs shall serve as water quality monitoring wells beyond the Project wellfield for this permit. In addition, selected recovery wells shall serve as monitoring wells for water quality monitoring and verification during the rinsing and post-rinse monitoring periods referred to as rinse verification and closure verification wells. RVW and CVW locations shall be established in accordance with the MGA Testing, Monitoring, and Corrective Action Plan and Attachments P and Q of the permit application in Appendix C and I of this permit. The ~~proposed~~ MWs, AOR wells, OWs, and other water quality monitoring wells shall be constructed at the locations depicted in Figures

A-1~~, and~~ A-2, A-4, and A-5 of Appendix A unless EPA approves a different location pursuant to Part II.C.1.b. and II.C.8. ~~, and s~~Sampling procedures are described in Section d of Attachment P and Table P-2 in Appendix I. ~~The proposed activation~~The MWs, AOR wells, OWs, and other water quality monitoring wells for each mine area or group shall be activated according to the schedule and sequence in Appendix I and described in this Section II.F. ~~for those wells is preliminary and subject to later revision and EPA review and approval as ISR operations for each mine area or group proceeds in Blocks 1, 2 and 3.~~ EPA may require the MWs and AOR wells depicted as potential future sets A and B in Figures A-1 and A-2 of Appendix A. With the exception of the wells for Block 2, the observation, AOR, and monitoring wells ~~will~~ shall be installed at least one year prior to the commencement of solution mining in a block to ensure adequate baseline data has been established as described in Section e of Attachment K and Attachment P in Appendix I.

~~The~~ MW-7, AOR-7, and associated OW-7 (Group 7) and MW-3, AOR-3, and associated OW-3 (Group 3) wells shall be installed with the initial Block 2 wells and be used for the LOM monitoring wells. The Permittee shall complete construction and activation of OW-9, OW-10, and OW-11 within 3 months of the effective date of the permit modification adding these OWs to the Permit, as illustrated in the proposed completion schematics in Appendix B of this Permit. At a minimum, OW-6 and OW-9 must be screened within the orebody and may be converted to I/R function as mining expands to their locations and additional OWs are in place. OW-9, OW-10, and OW-11 shall be placed within 500 feet surrounding the initial five (5) I/R wells, with at least one OW well downgradient and one OW upgradient of these initial I/R wells. OW-9, OW-10, and OW-11 in the mining area shall serve as observation monitoring wells for the initial five I/R wells until additional I/R wells are added and additional OWs are in place.

OW-6~~,~~ to be completed in the orebody as an I/R well shall serve with the initial five I/R wells in Block 2 as an operational OW located approximately 600 feet to the southeast of the initial I/R wells, towards Group 7 wells as depicted in Figure A-3. The Permittee shall measure parameters at OW-6, OW-9, OW-10, and OW-11 specified for observation wells in Table F-1 and Part II.F.7. Hydraulic gradient monitoring in Block 2 ~~will~~ shall be conducted by measuring the potentiometric head in wells OW-6, OW-9, OW-10, OW-11, OW-7, MW-7, and AOR-7.~~, which extend south from the first five I/R wells in Block 2.~~

OW-6, OW-9, OW-10, and OW-11~~6~~ ~~will~~ shall be used to monitor the movement of mining related solutions and observe the hydraulic responses within ~~the orebody~~Unit 3 surrounding the initial five I/R wells. The data obtained from ~~OW-6~~these observation wells ~~will~~ shall be used for model calibration ~~at the end of the first operating year~~ as specified in Part II Section J. Results from these initial wells ~~will~~ shall be used to establish the optimal percent recovery to keep mining related solutions within the permitted injection zone.

Based on the operating and modeling results, EPA may require additional monitoring with the addition of a group or additional I/R wells to Blocks 1, 2, and 3 and/or other actions beyond those specifically listed in this permit. OW-6 and any other operational OW ~~will~~may be constructed as an I/R well and converted to I/R function as the area is developed.

For OW-9, OW-10, and OW-11, the Permittee shall collect baseline conductivity measurements to establish a representative baseline, propose action levels and procedures for detection of mining related fluids, and receive written approval of baseline data and procedures from EPA in accordance with Part II.F.7.a.i-iii. Because injection has already begun, the Permittee may propose representative baseline data for OW-9, OW-10, and OW-11 from an approved existing well upon demonstration that it is representative of the range of background specific conductance levels.

2. List 1 and List 2 Parameters, Alert Levels, and Groundwater Quality Limits

   a. List 1 Parameters: List 1 analytes include constituents of ISR solutions that are most likely to provide an early indication of groundwater impacts associated with the operation of the SX plant and the wellfield. List l analytes shown in Table F.1 below, shall be sampled at least quarterly from each MW, AOR well, and OW in accordance with the schedule described in Part II.F.4 of this permit.

   b. List 2 Parameters: List 2 analytes include probable constituents of the ISR solutions for which primary MCLs have been established pursuant to 40 CFR Part 141 and other relatively probable constituents that are likely to appear in greater concentrations in groundwater impacted by ISR solutions than in non-impacted grounwater. List 2 analytes shown in Table F.1, below, shall be sampled at least once semi-annually from each MW, AOR well, and OW in accordance with the schedule described in Part II.F.4 of this permit.

   c. Alert Levels (ALs): With the exception of the field parameters which will not be assigned ALs (except for pH), the Permittee shall establish ALs for List l and List 2 analytes subject to review and approval by EPA, as described in Attachment P-Monitoring Program in Appendix I of this permit. Where any conflict or inconsistency exists between Attachment P and the permit conditions, the permit condition shall supersede the language in Attachment P.

   d. Groundwater Quality Limits (GWQLs): The Permittee shall establish GWQLs for parameters with primary MCLs pursuant to 40 CFR Part 141, as follows:

      i. If the calculated AL is less than the MCL, then the GWQL shall be set equal to the MCL.

ii. If the calculated AL is greater than the MCL, then the GWQL shall be set equal to the AL.

Table F.1 - Sampling Frequency and Constituents to be Measured		
Well Class	**Parameters**	**Frequency**
Monitoring Wells Quarterly List 1	TDS, As, B, Ca, Cl, Cr, Na, SO_4, Se, Mg, F	Quarterly
	Temperature, Specific Conductance, pH	Quarterly
Monitoring Wells Initial List 2	Alkalinity, Bicarbonate (CaCO3), Alkalinity Total (as CaCO3), Al, Sb, As, B, Ba, Be, Cd, Ca, Cl, Cr, Cu, F, Fe, Pb, Mg, Mn, Hg, Nitrate + Nitrite (as N), Nitrogen, Total (as N), pH, K, Se, Ag, Si, Na, SO_4, Tl, Li, TDS, Zn, TPH, BTEX, naphthalene, octane, Radioactive Chemicals in List 2a	First 8 to 12 Monthly Samples, then semi-annually
Observation Wells	Hydrostatic Pressure (water level), Temperature, Specific Conductance, pH	Continuous, except for periods of maintenance; Monthly data downloads
Rinse Verification/Post-closure Wells	Monitoring Wells Quarterly List 1	Quarterly
	Temperature, Specific Conductance, pH	Quarterly

Note: The Permittee shall utilize the applicable analytical methods described in Tables IA-IH of 40 CFR §136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, other methods that have been approved by the EPA Administrator.

Note: Any organic compound not listed above shall be so listed if an MCL has been established for that organic compound and if the organic compound is detected in the injectate.

Note: Samples must be analyzed by an EPA or California certified laboratory.

List 2a	AL	GWQL
Formation-Related Radioactive Chemicals (pCi/L)		
Gross Alpha	TBD	TBD
Adjusted Alpha [1,2]	TBD	TBD
Gross Beta	TBD	TBD
Radium 226 and Radium 228 (combined)[1]	TBD	TBD
Radon	NA	TBD
Uranium isotopes[1]	NA	NA
Uranium (Total), micrograms/L	NA	TBD

TBD – To Be Determined

NA – Not Applicable

[1] These parameters are to be analyzed only if the concentration of Gross Alpha Particle Activity exceeds the parameter's AL or GWQL.

[2] Adjusted gross alpha includes radium-226 but excludes radon-222 and total uranium.

3. Baseline Data and Statistical Methods

Prior to the commencement of injection, the Permittee shall:

a. Collect baseline water quality samples and analyze for all List l and List 2 parameters such that accepted statistical methods can be applied to assign ALs and GWQLs at all MWs, AOR wells, and OWs. For Process-Related Organics (List 2), two (2) months of data collection with nondetectable organic levels will be sufficient for background characterization. For the initial observation, AOR, and monitoring wells for Block 2, six (6) months of data collection with little to no variability of constituents will be sufficient for baseline characterization subject to EPA review and approval.

b. Submit to EPA a report containing mean baseline concentrations, standard deviations, ALs, and GWQLs, based on statistical methods used to establish ALs and GWQLs, as described in Attachment P in Appendix I of this permit, or based on other methods approved by EPA, which:

   i. establishes a means of verifying whether or not USDWs are endangered during Project recovery operations, rinsing, and post-rinsing, and

   ii. establishes specific points at which contingency plans are activated.

c. Receive written approval from EPA for the baseline data, action levels, and statistical approach defined at paragraph 3(b) of this Section F, above.

4. Water Quality Monitoring Schedule

The Permittee shall comply with the monitoring schedule in Table 3 at the seven (7) monitoring wells, six (6) AOR wells, and ~~seven (7)~~ten (10) OWs and at any additional monitoring wells and AOR wells that EPA may require during the approximately twenty-five (25)-year Project operation and restoration life and the five (5)-year post-rinse monitoring period:

Table 3. Monitoring Schedule for the MWs, AOR Wells, and OWs during Project Life and Post-Rinse Period

Time Period	Water Quality Parameters	Sampling Frequency
Project operation	List 1	At least once per quarter
	List 2	At least once semi-annually
Post-rinse	List 1	At least once per quarter for the first two (2) years after closure
	List 2	At least once semi-annually

Note: List 1 and List 2 Water Quality Parameters are defined at Part II, Section F.2 in Table F.1.
Also, some List 2 parameters may be sampled less than semi-annually if EPA grants a reduction in sampling frequency in accordance with Section F.5 of the Permit.

5. If any analytical result for a constituent is reported as non-detect for four (4) consecutive samples, then the Permittee may request that the analyte be removed from either List 1 or List 2 (includes List 2a), subject to EPA review and approval.~~. Additionally, the Permittee may request a reduction in frequency in sampling if there are no exceedances for four (4) consecutive samplings, subject to EPA review and approval.~~ The Permittee may monitor a constituent in List 2 (including List 2a) at a reduced frequency (from semi-annually) with written approval from EPA if no exceedences of the alert level for the constituent have occurred over four (4) consecutive sampling events. The sampling frequency may be reduced in accordance with written approval from EPA.

6. Monitoring Wells, AOR Wells, and Observation Wells

External monitoring of the ISR process around the perimeter of the Project wellfield shall be conducted to verify hydraulic control and detection of excursions of ISR fluids. This monitoring of the zone shall be performed using seven (7) MWs, six (6) AOR wells, and seven (7) OWs at the perimeter of the wellfield and any additional MWs and AOR wells that may be required as specified in Section F.1. Hydraulic control monitoring will require using MWs/AOR wells/OWs for head comparison and for verifying that the hydraulic gradient is inward, that is, from the AOR wells toward the closest MW and from the MWs toward the closest OW. Head monitoring ~~will~~ shall be accomplished using pressure transducers placed in the MWs, AOR wells, and OWs from which average daily head measurements ~~will~~ shall be recorded. In addition, the Permittee shall monitor specific conductance in the OWs to verify that hydraulic control is maintained and to detect any excursion in accordance with the approved procedures defined in paragraph 7.a, of this Section F. Revisions to the installation and activation schedule, choice, location and number of MWs, AOR wells, and OWs to be monitored during ISR and rinsing operations in the three mine Blocks shall be subject to EPA review and approval as ISR operations proceed in each mine Block, as described at Section F.1.

7. Specific Conductance Monitoring

   a. Prior to commencement of injection in a new mine block, the Permittee shall comply with the following conductivity sensor monitoring requirements:

      i. The Permittee shall collect baseline conductivity measurements to establish the range of background specific conductance levels and baseline specific conductance in the MWs, AOR Wells, and OWs.

      ii. For the purpose of detecting any loss of hydraulic control or any excursion of injection or ISR fluids, the Permittee shall submit to the EPA a report describing the results of baseline measurements and proposed procedures for identifying a statistically significant increase above statistical noise levels in specific conductance values at the MWs. AOR wells, and OWs confirming a loss of hydraulic control and a possible excursion requiring contingency actions.

      iii. Receive written approval from EPA for the baseline data, proposed action levels, and proposed procedures.

   b. During Project ISR and rinsing operations, the Permittee shall monitor specific conductance in the OWs, AOR wells, and MWs on a daily basis.

8. Injectate Solution Monitoring

The Permittee shall comply with the following injectate solution monitoring requirements:

   a. At least once per month, the Permittee shall measure the pH and the total concentration of total petroleum hydrocarbons (TPH) – diesel, BTEX (total), napthalene, and octane in the injectate solution using applicable analytical methods described in Tables IA-IH of 40 CFR §136.3, in USEPA SW-846, Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods, unless other methods have been approved by EPA. The Permittee may request monthly monitoring be reduced to quarterly monitoring if the listed organics concentrations do not vary significantly during the first six (6) months of sampling. The requirement for monthly monitoring will be reinstated if concentrations vary significantly during quarterly sampling.

b. The Permittee shall modify the list of organic constituents required under the injectate solution monitoring program defined at paragraph 8(a) of this Section F, above, if the Permittee has received written approval from EPA for a change in the injectate solution, as detailed at Part II Section E.6. of this permit, and the list described in paragraph 8(a) of this Section F does not include all organic constituents which are present or could be present in the injectate solution. Monitoring for naphthalene and octane may be discontinued if not detected in the first six (6) monthly sampling events.

c. The Permittee shall measure inorganic constituents in the PLS and injectate at least once per month using applicable analytical methods described in Tables IA-IH of 40 CFR §136.3, in USEPA SW-846 unless other methods have been approved by EPA. The inorganic analytes to be measured shall include all constituents listed in Table H-1, Appendix E of this permit. The Permittee may request monthly monitoring be reduced to quarterly monitoring if the listed inorganics concentrations do not vary significantly during the first six (6) months of sampling, subject to EPA review and approval. The requirement for monthly monitoring will be reinstated if concentrations vary significantly during quarterly sampling.

d. The Permittee shall modify the list of inorganic constituents described in paragraph 8(c) of this Section F in accordance with the requirements of Part II, Section E.6 of this permit.

e. The Permittee shall measure for formation related radioactive chemicals from List 2a in the PLS at least once per quarter using applicable analytical methods described in Tables IA-IH of 40 CFR §136.3 or in USEPA SW-846 unless other methods have been approved by EPA. The Permittee may request quarterly monitoring be reduced and parameters removed from List 2a if constituents are not detected in the first four quarters, subject to EPA review and approval. The constituents may be added back to List 2a if detected in later PLS sampling.

9. Groundwater Elevation Monitoring.

Groundwater depths and elevations, measured in feet relative to mean sea level, in the MWs, AOR wells, and OWs (including the operational OW required in Section F.1) shall be measured continuously, monitored daily, recorded monthly, and reported quarterly in accordance with Part II, Section G.2.e or G.2.n of this permit.

10. Subsidence Survey

The Permittee shall conduct a subsidence survey at least every two years. The survey ~~will~~ shall either be conducted by satellite, such as U.S. Geological Survey's Interferometric Synthetic Aperture Radar (InSAR) or equivalent, or by a licensed surveyor. All survey points shall be tracked in a spreadsheet and plotted on a graph to identify any changes in surface elevations.

11. Monitoring Information

Records of monitoring activity required under this permit shall include:

a. Date, exact location, and time of sampling or field measurements;

b. Name(s) of individual(s) who performed sampling or measurement;

c. Exact sampling method(s) used;

d. Date(s) laboratory analyses were performed;

e. Name(s) of individual(s) who performed laboratory analyses;

f. Types of analyses; and

g. Results of analyses.

12. Monitoring Devices

a. Continuous monitoring devices

Temperature and injection pressure shall be measured using equipment of sufficient precision and accuracy, as described below. All measurements must be recorded at minimum to a resolution of one tenth of the unit of measure, except temperature (i.e., injection and production rates and volumes must be recorded to a resolution of a tenth of a gallon; pressure must be recorded to a resolution of a tenth of a psi gauge (psig); injection fluid temperature must be recorded to a resolution of one-degree Fahrenheit). Exact dates and times of measurements, when taken, shall be recorded and submitted. Injection and production rates shall be measured at or near the wellhead. Injectate temperature can be measured at a central distribution point. Produced fluid temperature shall be measured at or near the wellhead. The Permittee shall continuously monitor and shall record the following parameters at the prescribed frequency shown in Table 4.

Table 4. Continuous Monitoring

Parameters	Frequency	Instrument
Injection rate (gpm)	Continuous	digital recorder
Daily injection volume (gallons)	Daily	digital totalizer
Total cumulative injection volume (gallons)	Continuous	digital totalizer
Injection pressure (psig)	Daily	digital recorder
Injection fluid temperature (degrees Fahrenheit)	Daily	digital recorder
Production rate (gpm)	Continuous	digital recorder
Daily produced fluid volume (gallons)	Daily	digital totalizer
Total cumulative produced fluid volume (gallons)	continuous	digital totalizer
Produced fluid temperature (degrees Fahrenheit)	Daily	digital recorder
Specific conductance (mmhos/cm)[1]	continuous	digital recorder

[1] If continuous digital recorder is not operational due to maintenance of recorder or well, at least one sample every 8 hours ~~will~~ shall be collected manually and the data ~~will~~ shall be used for confirmation of permit compliance.

b. Calibration and Maintenance of Equipment

All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order.

G. RECORDKEEPING AND REPORTING

1. Recordkeeping

The Permittee shall retain the following records and make them available at all times for examination by an EPA inspector:

a. All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the permit application;

b. Information on the physical nature and chemical composition of all injected fluids; and

c. Records and results of MITs, any other tests required by EPA, and any well work-overs completed.

d. The Permittee shall maintain copies (or originals) of all records described in paragraphs (a) through (c) above during the operating life of the wells and post-rinse monitoring period and shall make such records available at all times for inspection at the facility.

e. The Permittee shall only discard the records described in paragraphs (a) through (c) if:

i. The records are delivered to the EPA Region 9 Groundwater Protection Section, or

ii. Written approval from EPA to discard the records is obtained.

2. Reporting of Results

The Permittee shall submit, in accordance with the required schedule set out in Section G.3, accurate reports to EPA containing, at minimum, the following information:

a. A map showing the current Project operational status and groundwater elevation contours based on the current monthly monitoring data.

b. A table and graph showing daily cumulative injection volumes and recovery volumes and the monthly percent recovery to injection volume in the Project over the reporting period. The report shall identify any 30 day periods in which the volume recovered does not exceed the volume injected by at least 0.5 percent, any allowable variance, and any contingency actions taken during the reporting period.

c. A table and graphs comparing daily average head measurements in the OWs surrounding the Project wellfield with the same measurements in the MWs and AOR wells closest to each OW and a calculation of the hydraulic gradients between the three well group.

d. A table and graph showing results of the specific conductance measurements and depths in the OWs, AOR wells, and MWs compared to the established background and action levels identifying any statistically significant increase above statistical noise levels in conductivity values. The record shall also include a discussion of any exceedance that occurred, an evaluation of whether an excursion has occurred, and mitigating actions taken during the reporting period.

e. A table showing OW, MW, AOR well groundwater depths and elevations, analytical results, GWQLs, and Als along with a summary narrative, plus a graphical presentation of those results since inception of monitoring for the current reporting quarter. The records should also include a discussion of any exceedance of an GWQL or deviation from the minimum 0.01 ft./ft. inward hydraulic gradient that occurred, any temporary variances, and mitigating actions taken during the reporting period.

f. Results of monthly analyses of organics in the lixiviant.

g. Results of monitoring required at Part II.F.8 (pursuant to 40 CFR §146.33(b)(l)) whenever the injection fluid is modified to the extent that previously reported analyses are incorrect or incomplete.

h. Results of mechanical integrity tests conducted during the reporting period.

i. A summary of any plugging and abandonment activity conducted during the reporting period.

j. A summary of rinsing and closure operations conducted during the reporting period, including monitoring data from rinse verification and closure verification wells.

k. A table showing the average, maximum, and minimum monthly tubing/casing annulus (if applicable) and injection pressures.

l. If action is taken under either paragraphs (a) or (b) of Section H.1, a description of the causes and impacts of the loss of hydraulic control or the variance from the required recovery to injection ratio and the actions that were taken to correct the event.

m. A spreadsheet of subsidence survey points tracked during the reporting period and graph to identify any changes in surface elevations.

n. A table showing the operational OW groundwater depths, elevations, and specific conductance measurements compared to the established background and a summary of other monitoring data. A table and graph comparing daily average head measurements in the operational OW in the orebody with the same measurements in Group 7 wells and a calculation of the hydraulic gradient between the four wells.

3. Submission of Quarterly Reports

Quarterly reports shall be submitted by the dates listed below:

Reporting Period	**Report Due**
Jan, Feb, Mar	April 30
Apr, May, June	July 30
July, Aug, Sept	October 30
Oct, Nov, Dec	January 30

4. Formation Testing and Geophysical Well Logging Reports

Copies of all reports of formation testing and geophysical well logging conducted prior to beginning ISR operations shall be submitted to EPA and reviewed and approved by EPA before commencement of ISR operations is authorized. The Permittee may submit the required reports and logs on an individual well basis as the reports and logs become available or as a package submittal for a group of wells in a specific mine area.

5. Submittal Address

Copies of the monitoring results, all reports, and other information required by this permit shall be submitted to the following address:

U.S. Environmental Protection Agency, Region 9
Groundwater Protection Section (WTR-4-2)
75 Hawthorne St.
San Francisco, CA 94105-3901

The Permittee shall also submit electronic copies to the Manager of the Groundwater Protection Section, U.S. EPA Region 9.

H. CONTINGENCY PLANS

1. Loss of Hydraulic Control

   a. The Permittee shall initiate the following actions within 24 hours of becoming aware that the volume of fluids recovered from the injection and recovery zone of the active mine area during a 30-day period is less than 100.5 percent of the amount of fluid injected during the same 30-day period:

      i. adjust the flow rate for the recovery and/or injection wells to restore the percent of recovered fluid volume to at least 100.5 percent of the injected volume,

      ii. inspect the injection and recovery lines, pumps, flow meters, totalizers, pressure gages, pressure transducers and other associated instruments and facilities,

      iii. initiate pressure testing of wells if the loss of fluids cannot be determined to be caused by a surface facility failure, and

      iv. repair the system as necessary to restore the percent of recovered fluid volume to at least 100.5 percent of the injected volume.

   b. A loss of hydraulic control is deemed to occur when the amount of fluid recovered during a 30-day period is less than 100.5 percent of the amount of fluid injected during the same 30-day period.

      Loss of hydraulic control is also defined by an inward gradient (in head differential) of less than 0.01 ft./ft. or an outward gradient observed in any OW/MW/AOR three well group over a 48-hour period or by an action level in conductivity values above statistical noise levels in OWs over a 48-hour period. An inward gradient of less than 0.01 ft./ft. (i.e., loss of hydraulic control) shall require action to restore the inward gradient to at least 0.01 ft./ft. in the subsequent 24-hour period.

The minimum extraction/injection flow ratio of 100.5 percent and head differentials may be adjusted during the ISR operation if warranted by specific conductance data from OWs or head data from OW/MW/AOR three well groups, subject to EPA review and approval.

The Permittee shall initiate the following actions within 24 hours of becoming aware of the loss of hydraulic control within the Project area, as defined above. The Permittee shall:

i. cease or reduce injection in one or more wells as necessary to restore hydraulic control,

ii. operate injection and recovery wells to reverse a confirmed loss of hydraulic control and an excursion indicated by a specific conductance exceedance at an MW, AOR well, or OW until the SC returns to the baseline level at the well or wells and the amount recovered equals an amount sufficient to restore the ratio of fluid recovered to injected during the prior 30-day period to a minimum of 100.5 percent, and restore all OW/MW/AOR three-well group head differentials to at least 0.01 ft./ft. to verify an inward hydraulic gradient.

iii. verify proper operation of all facilities within the Project area, and

iv. perform any necessary repairs.

c. If action is taken under either paragraphs (a) or (b) above, the Permittee shall, in the next quarterly report, describe the causes and impacts of the exceedance, loss of hydraulic control, and/or the variance from the required recovery to injection ratio and head differential and the actions that were taken to correct the event.

2. Water Quality Exceedances at monitoring, AOR, and observation wells

The following describes contingency plans to be followed after the verification of an AL or GWQL exceedance in a MW, AOR, or OW during the approximately twenty-five (25)-year operation and restoration life and during the five (5)-year post-rinse monitoring period:

a. In the event of an AL exceedance during operational Project Life:

i. The Permittee shall collect a verification sample within five (5) days after becoming aware of an exceedance of an established AL per Part II.F.2 of this permit.

ii. Within five (5) days after receiving the results of verification sampling from the laboratory, the Permittee shall notify EPA in a written report if the results indicate an exceedance.

iii. If the results of verification sampling indicate that an AL has not been exceeded, the Permittee shall notify EPA of the results. No further action is required until the next scheduled monitoring round.

iv. Within thirty (30) days of receiving the laboratory results verifying that an AL has been exceeded, the Permittee shall do the following:

(A) Submit a written report to EPA providing an evaluation of the cause, impacts, and any mitigation of the discharge responsible for the AL exceedance, or

(B) Submit a written report to EPA which definitively demonstrates that the AL exceedance resulted from an error(s) in sampling, analysis, or statistical evaluation.

v. Upon review of the report documenting the AL exceedance, EPA may require additional monitoring and/or action beyond those specifically listed in this permit.

b. In the event of an GWQL exceedance during operational Project Life, rinsing, or post-rinse monitoring period:

i. The Permittee shall collect a verification sample within five (5) days of becoming aware of an exceedance of an established GWQL per Part II.F.2 of this permit.

ii. Within five (5) days of receiving the results of verification sampling from the laboratory, the Permittee shall notify EPA of the results in a written report, regardless of whether the results are positive or negative.

iii. If the results of verification sampling indicate that an GWQL has not been exceeded, the Permittee shall notify EPA. No further action is required until the next scheduled monitoring round.

iv. Within thirty (30) days of receiving the laboratory results verifying that an GWQL has been exceeded, the Permittee shall do the following:

(A) Submit a written report to EPA providing an evaluation of the cause, impacts, and any mitigation of the discharge responsible for the GWQL exceedance, or

(B) Submit a written report to EPA which definitively demonstrates that the GWQL exceedance resulted from an error(s) in sampling, analysis, or statistical evaluation.

v. Upon review of the report documenting the GWQL exceedance, EPA may require additional monitoring and/or action beyond those specifically listed in this permit.

c. Verification Sample Requirements

The verification sample shall be collected only from the well in which an exceedance was detected and shall be analyzed for the constituents in List 1 of Table F.1 of Part II.F.2 of this permit. If the constituent that exceeded an AL or GWQL is one that is listed in List 2 of Table F.1 of Part II.F.2 but not in List 1 of Table F.1, the verification sample shall be analyzed for all constituents listed in List 1 and only for constituent(s) from List 2 that exceed the AL or GWQL.

I. RESTORATION and PLUGGING & ABANDONMENT

Pursuant to 40 CFR Parts 146.10 and 144.12, the Permittee shall comply with the Restoration Plan and the Plugging and Abandonment Plans in Appendix C in accordance with the schedule for groundwater restoration, groundwater monitoring, and plugging and abandonment activities to ensure adequate protection of USDWs. The Permittee shall also comply with the conditions at I.1 and I.2 below. Where any conflict or inconsistency exists between the Restoration and Plugging and Abandonment Plans and permit conditions, the permit conditions shall supersede the language in the Restoration and Plugging and Abandonment Plans.

1. Closure and Plugging and Abandonment Plan

a. Constituents with primary MCLs: Within 90 days after completing borate recovery operations in the injection and recovery zone of a specific mine area or group, the Permittee shall commence restoration activities for the zone. The groundwater in the injection and recovery zone shall be restored to concentrations which are less than or equal to primary MCLs defined at 40 CFR Part 141, or pre-operational background concentrations if the pre-operational background concentrations exceed MCLs. The Permittee shall follow the procedure detailed at (c), below.

b. Constituents without primary MCLs: In addition to constituents with primary MCLs, the Permittee shall ensure that injection activities do not cause constituents which do not have primary MCLs to impact USDWs in a way that could adversely affect the health of persons.

c. Closure and Plugging & Abandonment Procedure: The Permittee shall commence closure operations in the injection and recovery zone after borate recovery operations have been completed. During closure operations, the Permittee ~~will~~ shall cease injection of injectate and initiate rinsing of the injection and recovery zone by injection/recovery or recovery operations. At all times during injection and recovery zone rinsing, the Permittee shall maintain inward hydraulic gradients (i.e., maintaining hydraulic containment of the injection and recovery zone).

Closure of the wellfield ~~will~~ shall include rinsing to remove residual PLS, post-rinse monitoring, and well abandonment, as described in the Restoration Plan and Plugging and Abandonment Plan in Appendix C. After borate recoveries drop below the economic cutoff, ISR in each production area ~~will~~shall be deemed complete and the area ~~will~~ shall be rinsed until applicable water quality standards are met as follows: Either fresh make-up water ~~will~~ shall be injected into the closed well or recovered water ~~will~~ shall be treated with lime to adjust the pH and then reinjected. Wells may be rinsed individually or as a group. Groups ~~will~~ shall be rinsed by injecting into one well and recovery from the same or surrounding well(s). This process ~~will~~ shall be repeated until the recovered water field parameters, i.e. pH, conductivity, and temperature, are stable. There is no time limit on the rinsing phase during active operations as the recovered waters will be used in the plant as needed.

Once field parameters are stable and the pH is between 6.5 and 9 S.U.s, a sample ~~will~~ shall be collected from each well in the group and analyzed for the constituents identified in Table F-1. The well(s) ~~will~~ shall be added to the quarterly sampling list and monitored quarterly until the parameters for the well reach equilibrium for four quarters. The results of the sampling ~~will~~ shall be included in the quarterly report submitted to EPA for their review and ~~will~~ shall be incorporated into the groundwater modeling. EPA ~~will~~ shall be notified of the restoration of the ore~~-~~body related to the well(s) along with EPA forms 7520-19 for plugging and abandoning wells.

The Permittee ~~will~~ shall sample discharges for all constituents defined at Part II.F.2, Table F-1, List 2 of this permit. If results of the sampling show that one or more compounds are above primary MCLs and the pre-operational background concentrations, rinsing operations ~~will~~ shall continue until all compounds are below primary MCLs or the pre-operational background concentrations if pre-operational background concentrations exceed MCLs (GWQLs).

If the List 2 constituents in a well are below GWQL concentrations, the Permittee may discontinue rinsing that well until the end of the thirty (30)-day period described below. If the List 2 constituents in a well exceed the GWQLs, the Permittee shall continue rinsing operations until such time that List 2 constituent concentrations in the well are less than the GWQLs for the Project.

When all individual rinse verification well concentrations within the injection and recovery zone of a specific mine block are below the GWQLs, rinsing operations for all wells within the mine block ~~will~~ shall be discontinued for thirty (30) days. At the end of the thirty (30)-

day period, the wells shall be re-sampled and if List 2 constituent concentrations remain below the GWQLs in all wells, the Permittee may cease all rinsing activities for the wells in the injection and recovery zone of that mine block.

The Permittee shall document the results of the closure operation in the subsequent quarterly monitoring report and notify EPA of the schedule for plugging and abandonment operations at least thirty (30) days in advance of commencing plugging and abandonment operations at wells to be plugged in an abandoned mine area. The Permittee shall identify the wells and locations of those wells to be retained as CVWs during the post-closure monitoring period in a closure report. The Permittee shall submit the notification, the closure report, and an updated Plugging and Abandonment Plan and schedule for EPA review and approval. The wells shall be abandoned in accordance with the Plugging and Abandonment Plan (Appendix C) unless modified and approved for individual well conditions.

2. Post-Rinse Monitoring:

Monitoring at OWs, CVWs, and other Project monitoring wells: To ensure that the restoration required at Section II.I(1), above, accomplished the objective of returning the injection and recovery zone to primary MCLs (or pre-operational background concentrations) and thereby providing adequate protection to surrounding USDWs, the Permittee shall comply with the Restoration Plan in Appendix C of this permit, the post-rinse monitoring schedule at Part II Section F.4 of this permit and the GWQL exceedance contingency plan established in Part II, Section H.2, paragraph (b) of this permit. The post-rinse monitoring schedule at Part II Section F.4 may be extended beyond five (5) years if water quality standards are not met for five consecutive years at all closure verification wells, MWs, AOR wells, and OWs, and EPA deems it necessary to ensure adequate protection of USDWs. The Permittee shall submit a post-rinse notification and report, with documentation, to EPA within thirty (30) days following completion of the post-rinse monitoring program.

J. OPERATIONAL AND POST-RINSE AUDITS

Within three (3) months ~~of~~ after completing three (3) months of ISR operations with ~~the~~ OW-9, OW-10, and OW-11 in place ~~with~~for the initial I/R wells, the Permittee shall submit a groundwater flow model evaluation and updated report to review the potential pressure impacts from operations to the surrounding formation fluids and to USDWs and confirm the zone of endangering influence as described in Appendix H of this Permit. The permittee shall submit a groundwater flow model evaluation and updated report within six (6) months of the completion of the first year of ISR operations for each of the three Blocks and annually ~~every five (5) years~~ thereafter until mine closure. The schedule for these audits may be adjusted, depending on the progress of Blocks 1, 2, and 3 operations, subject to EPA review and approval. The Permittee may request to reduce the frequency ~~in updating the~~ groundwater flow model updates if the updated groundwater flow model from a given year does not vary significantly from the prior year's model. The frequency in updating the groundwater flow model may be reduced in accordance with written approval from EPA.

The groundwater flow model evaluation and updated report shall include: hydrographs; changes to the site conceptual model, if any; water balance(s); results of calibration and sensitivity analysis, as appropriate; model run logs; any changes to the input model parameters; specific conductance trend analysis for OWs and any constituents in the compliance monitoring program, if determined appropriate; updated quarterly groundwater contour maps; ~~and~~ updates to the groundwater flow model to assess particle tracking (fate and transport); and potential impacts on surrounding USDWs. The model shall assess the performance of the operating mine blocks, rinsing of mine blocks, capture associated with monitoring, AOR, and observation wells, and any changes to the post-rinsing period required by this permit and recommend adjustments to the post-rinse monitoring period based on updated groundwater flow modeling results.

K. DURATION OF PERMIT

The duration of this Class III permit shall include well construction, corrective actions, and demonstrations required prior to injection under permit conditions in Part II, Sections C, D, and E.2 of this permit. After injection is authorized, the duration of this Class III permit shall include the approximately twenty-five (25) year Project operation and restoration life and five (5) year post-rinse monitoring period unless terminated under the conditions set forth in Part III, Section B.1 of this permit. The duration of this Class III permit shall include any post-rinse monitoring required beyond five (5) years.

L. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The Permittee shall demonstrate and maintain financial responsibility and resources sufficient to meet the restoration and plugging and abandonment requirements established at Part II, Section I of this permit and described in the Restoration and Plugging and Abandonment Plan (Appendix C) and consistent with 40 CFR §144.52(a)(7) and 40 CFR Part 144 Subpart F, which the Director has chosen to apply.

a. The Permittee shall post an approved financial instrument such as a surety bond or other financial assurance in an initial amount of $776,650 for the initial thirteen (13) Project wells to guarantee groundwater restoration, groundwater monitoring, and plugging and abandonment activities for closure and post-closure requirements.

Authority to construct, inject, and operate the wells under the authority of this permit will be granted only after the financial instrument has been secured and approved by EPA.

b. The level and mechanism of financial responsibility shall be reviewed and updated before additional wells are constructed and periodically, upon request of EPA. The Permittee may be required to change to an alternate method of demonstrating financial responsibility. Any such change must be approved in writing by EPA prior to the change.

c. EPA may require the Permittee to estimate and to update the estimated restoration, plugging, and/or post-closure activity costs periodically. Such estimates shall be based upon costs that a third party would incur to carry out the required restoration activities, properly plug and abandon the wells, and perform post-closure monitoring activities, including materials, equipment, mud and disposal costs, and labor with appropriate contingencies.

2. Insolvency of Financial Institution

The Permittee shall submit an alternate instrument of financial responsibility acceptable to EPA within sixty (60) days after either of the following events occurs:

a. The institution issuing any bond or other financial instrument that is secured to demonstrate financial responsibility in accordance with Part II, Section L.1. of this permit files for bankruptcy; or

b. The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

Failure to submit an acceptable financial demonstration may result in the termination of this permit pursuant to 40 CFR §144.40(a)(1).

3. Insolvency of Owner or Operator

The permittee shall notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

M. ENDANGERED SPECIES ACT

EPA considered the Endangered Species Act, 16 U.S.C. 1531 et seq. Section 7 of the Act and implementing regulations (50 CFR part 402) to ensure that the Project is not likely to jeopardize the continued existence of any endangered or threatened species or adversely affect its critical habitat. The Permittee is subject to the Bureau of Land Management

(BLM) stipulations per the December 30, 1994 Plan of Operations approval and as described in the Biological Opinion for the Fort Cady Mining Project Plan Proposal in Appendix J of this Permit. As required by BLM, at least 30 days prior to construction activities, the Permittee shall conduct site surveys of sensitive species and their location. No later than 90 days after completion of construction activities for the first five I/R wells, each mining area or group, the Permittee shall submit a report of findings to EPA of any additional impacts to the desert tortoise habitat.

PART III. GENERAL PERMIT CONDITIONS.

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant (as defined by 40 CFR §144.3 and 146.3) into USDWs (as defined 40 CFR §§144.3 and 146.3).

Any underground injection activity not specifically authorized in this permit is prohibited. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and 40 CFR Parts 124, 144, 145, and 146. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. §300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of this permit does not convey property rights of any sort or any exclusive privilege, nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this permit shall be construed to relieve the Permittee of any duties under all applicable laws and regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

   EPA may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§124.5, 144.12, 144.39, and 144.40. The permit is also subject to minor modifications for causes as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the Permittee, does not stay the applicability or enforceability of any permit condition. EPA may also modify, revoke and reissue, or terminate this permit in accordance with any amendments to the SDWA if the amendments have applicability to this permit.

2. Transfers

   This permit is not transferable to any person unless notice is first provided to EPA and the Permittee complies with requirements of 40 CFR §144.38. EPA may require modification or revocation and reissuance of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

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

D. CONFIDENTIALITY

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

1. Name and address of the Permittee, or

2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply

   The Permittee shall comply with all applicable UIC Program regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions

   Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may also be subject to enforcement actions pursuant to RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense

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

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance

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

6. Property Rights

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

7. Duty to Provide Information

The Permittee shall furnish to EPA, within a time specified, any information which EPA may request to determine whether cause exists for modifying, revoking, and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this permit. Section 1445 of the SDWA, 42 U.S.C. § 300j-4.

8. Inspection and Entry

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

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

c. Inspect and photograph at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

Section 1445 of the SDWA, 42 U.S.C. § 300j-4.

9. Signatory Requirements

All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §144.32.

10. Additional Reporting Requirements

a. Planned Changes - The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility affecting any of the terms and conditions of the permit.

b. Anticipated Noncompliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

c. Compliance Schedules - Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

d. Twenty-four Hour Reporting.

i. The Permittee shall report to EPA any noncompliance which may endanger health or the environment. The following Information shall be provided orally within 24 hours from the time the Permittee becomes aware of the circumstances.

(A) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; and

(B) Any noncompliance with a permit condition, malfunction of the injection system, or loss of mechanical integrity, which may cause fluid migration into or between USDWs.

ii. A written submission of all noncompliance as described in paragraph d(i) of this Section III.E.10 shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

e. Other Noncompliance - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E. paragraph 10.d of this permit.

f. Other Information - If the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Continuation of Expiring Permit

a. Duty to Reapply - If EPA requires the Permittee to continue an activity regulated by this permit past the expiration date of this permit, the Permittee must submit a complete application for a new permit at least one hundred and eighty (180) days before this permit expires.

b. Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) until the effective date of a new permit, if:

i. The Permittee has submitted a timely and complete application for a new permit; and

ii. EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.