Underground Injection Control Program

AREA PERMIT

Class III In-Situ Production of Copper
Permit No. R9UIC-AZ3-FY16-1

Gunnison Copper Project
Cochise County, Arizona

Issued to:

Excelsior Mining Arizona, Inc.

Concord Place, Suite 300
2999 North 44th Street
Phoenix, Arizona 85018

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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,

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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 copper recovery (ISR) operations at the Gunnison Copper Project (Project). The Project is in Township 15 South, Range 22 East, Section 36 and Township 15 South, Range 23 East, Section 31 in Cochise County, Arizona, approximately 62 miles east of Tucson and 17 miles southwest of Willcox, Arizona, as depicted in Figure A-1 in Appendix A. The location is along Interstate 10 on the southeastern flank of the Little Dragoon Mountains. The Project will consist of approximately 1,400 Class III injection and recovery wells, thirty (30) hydraulic control (HC) wells, twenty-two (22) observation wells (OW), up to one hundred and twenty (120) rinse verification monitoring wells (RVW), up to thirty (30) intermediate monitoring wells (IMW), and five (5) point-of-compliance (POC) wells. It will be operational in three stages of in-situ leach mining over twenty-three (23) years at the Project site. Mine operations will be implemented in stages:

- Stage 1: Years 1 – 10
- Stage 2: Years 11 – 13
- Stage 3: Years 14 – 20
- Post production: Years 21 – 23 – Final rinsing
- Post-rinsing monitoring – 5 years or longer

Multiple mining blocks will be active during each stage. As mining of 17 individual blocks is completed, the mining operations will be followed by a rinsing period while mining proceeds to subsequent blocks. The final rinsing period for the last mining block is anticipated to be completed by Year 23. The Project will encompass an area of approximately 524 acres including an Area of Review (AOR) of 332 acres and a wellfield area of approximately 192 acres as depicted in Figure A7-A in Appendix A of the permit.

The permit authorizes injection of a dilute sulfuric acid solution into the copper oxide deposit at depths greater than 40 feet below the first contact with competent bedrock for copper recovery in a pregnant leach solution (PLS) and production of copper cathode in a solvent extraction/electrowinning (SX-EW) process at the surface. The copper oxide zone varies in thickness from 400 to 800 feet and is located approximately 400 to 1,400 feet below ground level at the Project site. The Project requires an EPA-approved aquifer exemption (AE) to proceed with ISR operations. The fully developed wellfield will include 1,400 injection and recovery wells interspaced approximately 71 feet apart in an alternating and repeating pattern and surrounded by at least thirty (30) hydraulic control wells and twenty-two (22) observation wells

(OWs) located at the perimeter of the wellfield and within the AOR and AE boundary that circumscribe the wellfield. In addition, five (5) point-of-compliance (POC) wells will be located at the AOR/AE perimeter downgradient of the wellfield. Intermediate monitoring wells (up to 30) will be placed within the wellfield surrounding the active mine blocks. A portion of the recovery wells will be used as RVWs during rinsing operations, and a portion of the RVWs will be used as closure verification monitoring wells (CVWs) during the post-rinsing monitoring period. The outer OWs will be used as specific conductance and groundwater monitoring wells during mining and rinsing operations and as groundwater quality monitoring wells during the post-rinsing period. HC well and IMW fluids will be monitored for specific conductance to detect outward movement of ISR fluids. Three proposed HC wells at the southern wellfield perimeter and three proposed HC wells at the eastern wellfield perimeter shall be utilized for monitoring specific conductance of injection zone fluids and groundwater quality during the first year of ISR operations.

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 forty-nine (49) pages plus appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by Excelsior Mining Arizona, Inc. (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 twenty-three (23)-year Project operation and restoration life and the five (5)-year post-rinsing 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-rinsing monitoring beyond five (5) years, if deemed necessary by EPA.

This permit is issued on June 22, 2018 and becomes effective on August 1, 2018.

Original signed by

Tomás Torres

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 D of this permit, the Permittee shall submit plans and specifications for procedures to the EPA Region 9, Drinking Water 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. Exempted Zone

   Concurrent with the issuance of this Permit, EPA is approving an Aquifer Exemption at the Project site. Pursuant to 40 CFR §§144.7 and 146.4, the exempted portion of the aquifer at the Project site is defined by the following lateral and vertical boundaries:

   a. Lateral Aquifer Exemption Boundary

      The AE encompasses 332 acres. This includes the area of the wellfield associated with the mining project plus the area within approximately 1,200 feet to the east (the direction of groundwater flow) and approximately 250 feet to the north of the proposed wellfield. The extent of the exempted area coincides with the AOR delineated for the Class III permit application. The AOR represents the area where injected fluids may migrate into USDWs, if not exempted, based on modeling of fluid movement performed by the applicant. This modeling approach, evaluated by the EPA as part of the Class III permit application evaluation, incorporates the geologic and operational characteristics of the proposed project. Refer to

Figure A-7A and Figure S-9 in Appendix A for a depiction of the exemption area.

b. Vertical Aquifer Exemption Boundaries

The upper and lower boundaries of the exempted aquifer are described in the Aquifer Exemption Record of Decision document in Exhibit S-1 in Appendix A, as the following:

The top of the exempted area is defined as the potential elevation of the top of the saturated zone in the basin fill formation that overlies the injection zone for the wellfield. Below the injection zone, the exempted aquifer extends 200 feet into a low-permeability sulfide zone below which the aquifer is not considered to contain a sufficient quantity of groundwater to supply a public water system due to its poor hydraulic conductivity. Refer to Figures D-3, D-4, and D-5 in Appendix A.

2. 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 three (23)-year operation and restoration life of the Gunnison ISR Project and five (5)-year post-rinsing 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 exempted zone described at Part II, Section B.1 and delineated as described in the Exhibit S-1, the Aquifer Exemption Record of Decision document in Appendix A of this permit.

3. Adequate Protection of USDWs.

Pursuant to 40 CFR §§144.12 and 146.10(a)(4), the Permittee shall adequately protect USDWs by commencing, within sixty (60) days after completing copper 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 to 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 F, Wellfield Closure Strategy, of this permit. Wells converted to closure verification wells and all HC, OW, RVW, and POC wells will be plugged and abandoned at the end of the post-closure monitoring period when all CVWs and outer OWs have met Aquifer Quality Limits (AQLs) for five consecutive years.

C. WELL CONSTRUCTION

1. Location of Project Wells

   a. The 1,400 project injection and recovery wells shall be contructed within the designated mining area for each stage delineated in Figure A-7A in Appendix A and located in Township 15 South, Range 22 East, Section 36 and Township 15 South, Range 23 East, Section 31 in Cochise County, Arizona (at coordinates 32 degrees, 5 minutes, 3 seconds North and 110 degrees, 2 minutes, 40 seconds West). The proposed injection and recovery well locations are listed in Tables 4.1-10, 4.1-11, and 4.1-12 in Appendix A. The Project wellfield will be approximately192 acres in size, as depicted in Figure A-7A. The Project is located approximately 62 miles east of Tucson, and 17 miles southwest of Willcox, Arizona. The location is along Interstate 10 on the southeastern flank of the Little Dragoon Mountains.

   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 in Sections 31 and 36 and latitude/longitude coordinates of the wells constructed under this permit, including all hydraulic control, observation, monitoring, and POC wells. The distances and direction of each HC, OW, and POC well from the Project wellfield boundary shall also be provided in the Final Well Construction Report required under paragraph 9(a) of this section. If final well coordinates differ significantly from the proposed coordinates described above, justification and documentation of any communication with and approval by EPA shall be included.

2. Logging and Testing during Drilling and Construction

   <u>Open-hole geophysical logs</u> shall be run in each well boring for formation evaluation, depth control, and detection of borehole anomalies. Geophysical tools shall include caliper, gamma-ray, directional survey, sonic, and acoustic borehole image (ABI) logs. Electrical logs shall be run in all outer OWs. In addition, compensated neutron-density logs may be required in at least one injection well boring within each of the 17 mine blocks to provide a more representative sampling of porosity values throughout the Project area. Porosity values determined from the neutron-density logs 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.

   <u>Cased-hole geophysical logs</u>, including gamma ray, temperature, and/or cement bond logs (CBLs), shall be run in all steel-cased injection, recovery, and other steel-cased wells over the entire length of each well casing after the steel casing has been installed and cemented in place. Gamma ray and temperature logs are required in fiberglass reinforced plastic (FRP) cased wells and polyvinyl cased

(PVC) wells for determination of the top of cement in the casing/wellbore annulus within 48 hours of cementing the casing. 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 Arizona Oil and Gas Conservation Commission's requirements in the Arizona Administrative Code, found at Title 12, Natural Resources, Chapter 7, Article I, R12-7-108 to R12-7-127, unless a section conflicts with UIC permit requirements. 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 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 to be provided for reporting forms such as EPA Form 7520-9, Completion of Construction Report, EPA Form 7520-12, Well Rework Record, or EPA Form 7520-14, Plugging and Abandonment Plan (refer to list in Appendix C) is also acceptable to include in the procedures. The Permittee shall also comply with the requirements of the Arizona Department of Water Resources minimum construction standards in the Arizona Administrative Code found at Title 12, Chapter 15, Article 8, Well Construction and Licensing of Drillers.

4. Well Casing and Drilling

Wells drilled and installed at the Project will include injection, recovery, HC, OW, and POC monitoring wells. Those wells shall be constructed to meet Class III requirements at 40 CFR §146.32. In addition, IMWs will be converted from existing test wells and coreholes or drilled within the wellfield perimeter at locations surrounding active mine blocks, for monitoring and controlling the movement of ISR fluids within the wellfield. Newly drilled IMWs shall also be constructed to meet Class III requirements.

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 shall be 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 into or out of the injection zone. 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 be documented in the Final Well Construction Report (See paragraph 9(a) below).

Boreholes will be drilled in two stages. After driving surface casing to a depth of 20 feet, the upper stage will consist of a boring drilled from land surface through basin fill at least 40 feet below the first contact with competent bedrock. After casing for the first stage is cemented in place, a smaller diameter borehole will be drilled into the bedrock to total depth. The borehole within the bedrock will remain open in most wells. Screen may be installed in the bedrock section in the borehole if found to be unstable. Borehole diameters will be sufficient to allow for installation of casing that will accommodate the pumps and other downhole equipment.

Casing materials to be used include FRP, low carbon steel (LCS) and Schedule 80 PVC. A well may have more than one type of casing, as depicted in Figures M-1, M-2, M-3, M-4, and M-5 in Appendix B. PVC may be used in the upper section of the borehole above the cement seal and FRP casing may be used in the lower grouted section. Alternatively, FRP may be installed throughout, or LCS casing may be installed above FRP casing with a packer to isolate lixiviant from the steel casing. Casing centralizers will be placed at 40-foot intervals along the casing and screen (if used) length.

5. Cementing

Injection and recovery well, HC well, OW, POC well, and new IMW casing will be cemented from a depth of 40 feet below the first contact with competent bedrock (minimum) to 100 feet above the basin fill/bedrock contact (or the top of the saturated basin fill, whichever is shallower). The cement will be pumped through a grout pipe inside the casing and fitted with a drillable cementing shoe with a backpressure valve to prevent grout from backing up into the casing when the grout pipe is removed. The lower section of each injection and recovery well will be drilled from the bottom of the cemented casing to the design depth. Clean fill will be placed from the top of cement to the ground surface using a tremie pipe.

Water and/or appropriate mud-breaker chemicals will 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. An excess quantity of cement (100 feet) will be pumped into the annular space to ensure placement of cement to the design depth prior to terminating the cementing operation. Following placement of the cement slurry, the cement will be allowed to cure for a minimum of 24 hours before performing additional operations on the well. The cement shall consist of sulfate resistant Portland Type V that is mixed thoroughly and free of lumps.

6. 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:

Subject to Part II.C.6.c.i, a conductivity sensor (CS) array shall be installed at strategic depths in open-hole intervals of the outer OWs to detect any preferential flow where faults intersect the wellbore and excursions during ISR and rinsing operations and to detect any exceedances of water quality standards during the post-rinsing monitoring period. In addition, single conductivity sensors will be placed at strategic depths in the IMWs for monitoring and control of ISR fluid movement. Conductivity sensors will also be placed in the three HC monitoring wells at the southern wellfield boundary and in three HC wells at the eastern wellfield boundary as replacements for SC monitoring in the three OW pairs associated with those HC wells in the first year of Stage 1 ISR operations, in accordance with Part

II.F.1. 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.

i. The Permittee may propose a demonstration of the equivalence of a single conductivity measurement to measurement using an array of CS in the open hole intervals of inner intermediate monitoring wells near the first mine block of Stage 1 ISR operations. If results fail to show that one CS sensor is sufficient to detect preferential flow or are inconclusive, multiple sensor arrays shall be placed in the outer OWs and inactive HC wells at the southern and eastern wellfield boundary used in Stage 1 operations. If results are inconclusive in the Stage 1 demonstration, the permittee may also propose similar demonstrations for Stage 2 and Stage 3 operations. If those demonstrations are not performed or the results fail to show that one CS sensor is sufficient or are positive or inconclusive, an array of multiple sensors shall be placed in the outer OWs used in Stage 2 and Stage 3 operations. The proposed demonstration procedures and results of the demonstration are subject to EPA review and approval.

7. Injection Interval

The Permittee shall only inject fluids at depths greater than forty (40) feet below the top of the competent oxide bedrock zone (“bedrock exclusion zone”) unless the Permittee has received written approval from the Director to expand the injection interval. To ensure that the injection interval is at least forty (40) feet below the top of the oxide bedrock zone, 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 at least one-hundred (100) feet above the bedrock surface or the top of the saturated zone, whichever is shallower, to at least forty (40) feet below the top of the oxide bedrock zone. The Permittee will develop the injection interval for each well by drilling into the oxide bedrock zone, beyond the bottom of the casing and cemented interval. Well screens in IMWs, observation, and POC wells will be installed through the oxide interval below the bedrock exclusion zone to a depth and interval equivalent to the open-hole or screened completion intervals in the nearest injection, recovery, and HC wells.

8. Injection Formation Testing

Aquifer testing will be performed upon installation of injection and recovery wells and used to determine the layout and number of recovery wells and injection and recovery rates in each mine block. 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 aquifer tests will be compared to parameters used in the groundwater flow model, and the model parameters will be revised accordingly if the resulting test parameters are significantly different from those used in the model.

9. 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), to EPA within sixty (60) days after completion of all Project wells within a specific mine block, including injection/recovery, HC, OW, monitoring, and POC wells. Construction details, downhole equipment, depths to key formation tops and the USDW base, if applicable, screened or open hole interval depths, and schematics of all Project wells shall be described in the Final Well Construction Report for each mine block.

   b. The Permittee shall also submit a notice of completion of construction to EPA (refer to EPA Form 7520-9 listed in Appendix G). Injection operations for a particular well or mine block may not commence until all related Project wells 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.

10. 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 and 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:

All existing non-Class III wells and coreholes within the proposed Project mine blocks and non-Class III wells and coreholes not intended for use as IMWs within 100 feet of a mine block shall be abandoned per the Plugging and Abandonment Plan (Appendix C of this permit). The identification, location, and construction details of the wells and coreholes to be plugged and abandoned or used as IMWs are listed in Table C-1 in Appendix C and the Plugging and Abandonment Plans (EPA Form 7520-14) for each well and corehole within the AOR are included in Appendix C. 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. If not provided within thirty (30) days, permittee may assume EPA approval and proceed with P&A operations.

E. WELL OPERATION

1. Description of Operations

The Description of Operations, in Attachment H-1 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 Description of Operations and the permit conditions, the permit condition shall supersede the language in the Description of Operations.

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

Stage 1 (1-10 years) 5,300 gallons per minute (gpm)

Stage 2 (11-13 years) 15,800 gpm

Stage 3 (14-20 years) 25,600 gpm

During ISR operations, the extraction rate of recovery and HC wells shall not fall below one-hundred-one (101) percent of the injection rate on a 48-hour rolling average basis without prior written approval of a lower percentage from EPA. Net extraction volumes shall be maintained at one percent (1%) or greater, depending on the maintenance of an inward gradient of no less than 0.01 ft./ft. between OW pairs 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 at all OW pairs. The choice and number of IMW, HC well and OW locations to be monitored during the three stages of ISR and rinsing operations shall be subject to EPA review and approval in accordance with Part II, Section F.5. The updated model and operational experience will be used to review and modify the proposed locations of HC wells, OWs, and IMWs in Stage 1 and 2 and beyond year 13 in Stage 3 of ISR operations.

An inward gradient of at least 0.01 ft./ft. between OW pairs shall be established prior to the commencement of injection of sulfuric acid solution and maintained for demonstrating hydraulic control unless adjusted by EPA as described 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 48-hour basis.

b. The Permittee may submit an operational and monitoring plan to demonstrate that a thirty (30)-day rolling average is as protective as the 48-hour flow volume re-balancing. If the Permittee demonstrates that re-balancing on greater than a 48-hour rolling average basis is as effective and protective as 48-hour 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 in the outer OWs to confirm hydraulic control at appropriate and approved depths throughout the monitored interval. Conductivity 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 extraction to injection ratio has fallen below one-hundred-one (101) percent or the inward gradient at any observation well pair is less than 0.01 ft./ft., or the specific conductance data in the outer OWs indicate a possible loss of hydraulic control. Actions shall also be taken on a timely basis to reverse outward ISR fluid movement detected in IMWs, HC, or other monitoring wells, and to contain ISR fluids to the wellfield during recovery, rinsing, and post-rinsing 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 block 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 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, other Project (POC, HC, and observation) wells, and newly drilled IMWs shall maintain mechanical integrity at all times. Pursuant to 40 CFR §146.8, the Permittee shall demonstrate mechanical integrity, Parts I and II 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 be installed immediately above the proposed injection interval, the wellbore will be completely filled with water, and a hydraulic pressure equal to or above the maximum allowable wellhead injection pressure but not less than 100 pounds per square inch (psi) will be applied. 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 pressure over the thirty (30) minute period. 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; 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 fluid movement through vertical channels adjacent to the well bore in existing test wells and coreholes that are converted to monitoring wells. Casing and cementing records shall be provided for all of the existing test wells and coreholes that will be converted to IMWs if the records are available. Part II mechanical integrity must be demonstrated in new monitoring wells as described below for new Project wells.

(B) 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 temperature log and casing caliper log shall be run in all new Project wells. Secondary temperature and tracer surveys may be required if a loss of external injection well integrity is detected or suspected. Secondary 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. Radioactive tracer surveys may also be required for evaluation of zonal isolation after injection commences in injection wells at the direction of EPA. 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.

(C) After installing and cementing the casing, conducting a cement squeeze operation, or any well cement repair, the Permittee shall provide to the Director 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 and PVC cased wells. Cementing records and logs shall demonstrate complete filling of the annulus between the borehole wall and well casing with cement to a depth at least one-hundred (100) feet above the bedrock surface or the top of the saturated basin fill, whichever is shallower.

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 or monitoring well. Injection and recovery 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 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 loss of mechanical integrity becomes evident during injection operations.

ii. Results of the MITs shall be submitted to the Director 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 operating 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

After the permit's effective date, the Permittee shall commence injection into the well 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 formations open to injection in the bedrock oxide zone. Based on field test data at the Project site, a variable fracture pressure, measured at the top of the injection interval, will be used to establish maximum hydraulic pressure which may be exerted at the surface. The maximum wellhead pressure calculation will be based on the lowest measured fracture gradient of the weakest formation(s) open to injection in each well, and be dependent 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 0.9 shall be applied in the calculation of the maximum allowable surface injection pressure. In wells that are open to the Escabrosa, Horquilla, Martin, upper Abrigo, middle Abrigo, and lower Abrigo formations, fracture gradients (adusted for the safety factor) of 0.7, 1.3, 0.94, 1.48, 1.27, and 0.87 psi/ft., respectively, shall be applied in the calculation. The maximum allowable surface injection pressure will be established for each injection well on that basis. Refer to Tables A and B in Appendix E for formation fracture pressure gradients of each formation.

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. In addition, the Permittee shall supply EPA with all documentation of actions implemented in compliance with Aquifer Protection Permit No. 511633 Section 2.6.2.5 for EPA review and approval.

b. The injection pressure limitations in paragraph 4(a) of this Section E may be increased by the Director based on the results of valid step-rate tests or other EPA-approved injectivity tests in the respective proposed injection zone. The Director 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 the Director 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 each of the three stages of mining operations as follows:

Stage 1 (1-10 years): 5,300 gpm or 7.632 million gallons per day (gpd)

Stage 2 (11-13 years): 15,800 gpm or 22.752 million gpd

Stage 3 (14-20 years): 25,600 gpm or 36.864 million gpd

The estimated maximum injection rates will vary in each of the three stages of mining as follows:

Stage 1 (1-10 years): 6,058 gpm or 8.724 million gpd

Stage 2 (11-13 years): 16,441 gpm or 23.675 million gpd

Stage 3 (14-20 years): 26,766 gpm or 38.543 million gpd

During ISR operations, the injection rate shall not exceed the recovery rate and the extraction rate of recovery and HC wells shall not fall below one-hundred-one (101) percent of the total wellfield injection rate on a daily average basis without prior written EPA approval. Net extraction volumes shall be maintained at one percent (1%) or greater, depending on the maintenance of an inward gradient of no less than 0.01 ft./ft. between observation well pairs on a daily average basis. If the inward gradient cannot be maintained at 0.01, the net extraction and/or recovery rate or volume shall be increased to achieve that minimum inward gradient at all OW pairs.

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 or beyond the Project wellfield AOR and AE boundary.

d. The 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 (lixiviant) shall consist of a dilute sulfuric acid solution that includes inorganic and organic constituents as defined below. The lixiviant shall have a pH of approximately 0.6 to 1.8. Organic compounds in the lixiviant shall be limited to those listed in Part II.Section F.7.(a) of this permit. The monthly concentration of total petroleum hydrocarbons (TPH) in the lixiviant listed in Part II. Section F.7(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 MCL exceedance in BTEX concentrations. The permittee may request an increase in the TPH limitation if after one month of sampling lixiviant with a higher TPH concentration, benzene, toluene, ethylbenzene and xylene (BTEX) concentrations are consistently below the MCLs. The demonstration may be extended up to six months if the initial results are considered inconclusive. 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 forecast composition of the injectate and other ISR process solutions is provided in Table H.1 in Appendix E. Inorganic constituents in the lixiviant shall be limited to constituents in the sulfuric acid, calcium carbonate, 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 lixiviant with groundwater and minerals in the oxide zone. Concentrations of inorganic constituents in the lixiviant 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 federal drinking water standards or pre-operational background concentrations, whichever are greater. The Permittee may also adjust the pH with sodium bicarbonate 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 the Director'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/EW process; (2) sulfuric acid to be used in the SX/EW process or to prepare solutions for injection; or (3) sodium carbonate 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 Material Safety Data Sheet (MSDS) 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 Level 1 or Level 2 groundwater monitoring program defined at Part II.F.2 and the injectate monitoring program defined at Part II.F.7 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 the Director's approval at least thirty (30) days prior to the date of the proposed use of the chemical and receives written approval from the Director. 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.7 as necessary to conform to the Director'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.7 apply only to injectate solution (lixiviant) prior to injection and to constituents of process chemicals that may become part of the lixiviant. The requirements do not apply to PLS that is being re-injected to increase the concentration of copper in the PLS before it is delivered to the SX/EW plant for processing.

F. MONITORING PROGRAM

1. Water Quality Monitoring Wells.

The POC and outer OWs shall serve as water quality monitoring wells beyond the Project wellfield for this permit. In addition, selected injection or recovery wells shall be converted to monitoring wells for water quality monitoring and verification during the rinsing and post-rinsing monitoring periods referred to as rinse verification and closure verification wells. RVW and CVW locations shall be established in accordance with the Wellfield Closure Strategy in Appendix F of this permit. The proposed HC, POC, and water quality monitoring well locations are depicted in Figures A-7A and A-8 of Appendix A, Table H-2 of Appendix E, and Table P-1 of Appendix I, and are described in Table P-1 in Appendix I. The proposed IMWs, observation, and hydraulic control well locations, stage of operation, and activation sequence are listed in Tables 2.5-1, 2.5-2, and 2.5-3 in Appendix A. The proposed activation schedule and sequence for those wells is preliminary and subject to later revision and EPA review and approval as ISR operations for each mine block proceed in Stages 1, 2 and 3.

In addition, any POC wells established for monitoring the effects of injection and natural groundwater movement within the Project AOR, pursuant to a final Aquifer Protection Permit to be issued to the project by the Arizona Department of Environmental Quality, will also serve as water quality monitoring wells for this permit. The water quality monitoring well designs are shown in Figures M-4 and M-5 in Appendix B.

Purging of wellbore fluids (3 wellbore volumes) shall be required before collecting groundwater samples from Project monitoring wells (OW, POC wells, RVWs, CVWs, and inactive HC wells) unless EPA approves the use of hydrasleeves or similar non-purging devices for collection of water samples, if applicable. Excelsior shall provide justification for using hydrasleeves or similar type samplers to demonstrate that it provides an equivalent or superior sample quality or are necessary due to very low recharge rates. Hydrasleeves or similar devices may be allowed or required when applicable for collection of water samples in wells that display stratification of water quality and at the intersection of high permeability zones and preferential pathways in a wellbore.

The three proposed HC wells (HC-2, HC-3, and HC-4) located at the southern AE/AOR boundary as depicted in Figure 52 and A-13 (Appendix A) shall be installed prior to commencing ISR operations in year one (1). The Permittee shall monitor specific conductance (SC) and water levels in the three inactive HC wells at the southern boundary and designated IMWs for alert levels daily. Electric logs shall be run in these wells for baseline electrical resistivity and conductivity profiles in the open hole interval in addition to the other required geophysical logs. Groundwater samples shall be collected for analysis of SC and other Level 1 indicator parameters at least once per month for at least the first year in the HC wells as a backup and comparison to the daily SC monitoring. Purging of wellbore fluids (3 wellbore volumes) shall be required before collecting samples of water in the subject HC wells for SC and other Level 1 parameter data unless EPA approves the use of hydrasleeves or similar non-purging devices for collection of water samples, if applicable as described above.

A demonstration of an inward gradient at the southern wellfield perimeter is not required in the first year of ISR operations, but extraction rates shall exceed injection rates by at least one (1) percent regardless of the inward gradient monitoring. The SC and water level monitoring in the outer IMWs will serve as an early warning system, which will trigger increased extraction rates from the mine block or existing HC wells at the eastern boundary or activation of more HC wells at the eastern boundary if necessary to regain HC at the southern boundary.

In the event of a verified exceedance of SC levels detected by transducers or by sampling in the HC wells at the southern boundary, contingency actions shall be implemented immediately to correct the apparent loss of HC and an excursion. A verified exceedance will require activation of pumping at the HC wells and installation of three associated OW pairs at locations subject to EPA approval, as soon as possible, for inward gradient monitoring and SC monitoring in the outer OWs at the southern boundary.

Three HC wells (HC-10, HC-13, and HC -19) located at the eastern wellfield boundary as depicted in Figure A-7(Appendix A) shall be installed as monitoring wells prior to commencing ISR operations in year one (1). The Permittee shall monitor specific conductance (SC) and water levels in these three wells at the eastern boundary and designated IMWs for alert levels daily. Electric logs shall be run in these wells for baseline electrical resistivity and conductivity profiles in the open hole interval in addition to the other required geophysical logs. Groundwater samples shall be collected for analysis of SC and other Level 1 indicator parameters at least once per month for at least the first year in the HC wells as a backup and comparison to the daily SC monitoring. Purging of wellbore fluids (3 wellbore volumes) shall be required before collecting samples of water in the subject HC wells for SC and other Level 1 parameter data unless EPA approves the use of hydrasleeves or similar non-purging devices for collection of water samples, if applicable as described above.

A demonstration of an inward gradient at the three inactive HC wells at the eastern wellfield perimeter is not required in the first year of ISR operations, but extraction rates shall exceed injection rates by at least (one) 1 percent regardless of the inward gradient monitoring. The SC and water level monitoring in the outer IMWs will serve as an early warning system, which will trigger increased extraction rates from the mine block or existing HC wells at the eastern boundary or activation of more HC wells at the eastern boundary if necessary to regain HC at the eastern boundary.

In the event of a verified exceedance of SC levels detected by transducers or by sampling in the HC wells at the eastern boundary, contingency actions shall be implemented immediately to correct the apparent loss of HC and an excursion. A verified exceedance will require activation of pumping at the HC wells and installation of the OW pairs associated with HC-10, HC-13, and HC-19 as depicted in Figure A-7 and listed in Table 2.5.2 in Appendix A, as soon as possible. The OWs will be used for inward gradient monitoring and SC monitoring in the outer OWs at the eastern boundary.

2. Level 1 and Level 2 Parameters, Alert Levels, and Aquifer Quality Limits

   a. Level 1 Parameters: Level 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/EW plant and the wellfield. Level l analytes shown in Table 1 below, shall be sampled at least quarterly from each POC and outer observation/monitoring well in accordance with the schedule described in Part II.F.4 of this permit. Refer to Table P-3 in Appendix I for POC well monitoring details.

   b. Level 2 Parameters: Level 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 groundwater. Level 2 analytes shown in Table 2, below, shall be sampled at least once annually from each POC and outer observation/monitoring well in accordance with the schedule described in Part II.F.4 of this permit. Refer to Table P-4 in Appendix I for POC well monitoring details .

   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 Level l and Level 2 analytes subject to review and approval by EPA, as described at Section 2.4 in Attachment P, Monitoring Program (Alert Levels), and the statistical methods described in Section 2.5.3.1.2.1 in Appendix I of this permit. Where any conflict or inconsistency exists between Attachment P or Section 2.5.3.1.2.1 and the permit conditions, the permit condition shall supersede the language in Attachment P and Section 2.5.3.1.2.1. The procedures for establishing ALs for POC wells described in Appendix P and Section 2.5.3.1.2.1 shall also apply to the outer OWs and inactive HC wells at the southern and eastern wellfield perimeter.

   d. Aquifer Quality Limits (AQLs): The Permittee shall establish AQLs 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 AQL shall be set equal to the MCL.

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

Table 1: Water Quality Parameters - Level 1

Parameter (mg/L unless noted)	AQL	AL
Fluoride	TBD	TBD
Magnesium	NA	TBD
Sulfate	NA	TBD
Total Dissolved Solids	NA	TBD
pH, units (field)	NA	TBD
Specific Conductance, micromhos/cm (field)	NA	NA
Temperature, deg F or deg C	NA	NA

Note: The Permittee shall utilize the applicable analytical methods described in Table I 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.

AQL - Aquifer Quality Limit (as defined at Part II.F.2.d)

AL - Alert Level

TBD - To be determined and approved by the director for the POC wells, inactive HC wells at the southern and eastern wellfield perimeter, and observation wells required by EPA according to the final installation schedules for these wells. The final schedule for POC well, HC well, and OW installation will be subject to EPA review of ISR operations performance and monitoring data as operations proceed.

NA - Not applicable: Shall be measured and reported but no contingency level shall be established.

Table 2: Water Quality Parameters - Level 2

Parameter	AQL	AL
Common Ions (mg/L unless noted)		
pH (field), units	NA	NA
Specific conductance (field), micromhos/cm	NA	NA
Temperature (field), deg F or deg C	NA	NA
pH (lab)	NA	NA
Bicarbonate	NA	NA
Calcium	NA	NA
Carbonate	NA	NA
Chloride	NA	NA
Fluoride	TBD	TBD
Magnesium	NA	TBD
Nitrate-N[1]	TBD	TBD

Parameter	AQL	AL
Nitrite-N	TBD	TBD
Potassium	NA	NA
Sodium	NA	NA
Sulfate	NA	TBD
Total dissolved solids	NA	TBD
Cation/Anion balance	NA	NA
Formation-Related Metals (mg/L)		
Aluminum	NA	TBD
Antimony	TBD	TBD
Arsenic	TBD	TBD
Barium	TBD	TBD
Beryllium	TBD	TBD
Cadmium	TBD	TBD
Chromium (Total)	TBD	TBD
Cobalt	NA	TBD
Copper	TBD	TBD
Iron	NA	TBD
Lead	TBD	TBD
Manganese	NA	TBD
Mercury (inorganic)	TBD	TBD
Nickel	NA	TBD
Selenium	TBD	TBD
Thallium	TBD	TBD
Zinc	NA	TBD
Formation-Related Radioactive Chemicals (pCi/L)		
Gross Alpha	TBD	TBD
Adjusted Alpha [2,3]	TBD	TBD
Gross Beta	TBD	TBD
Radium 226 and Radium 228 (combined)[2]	TBD	TBD
Radon	NA	TBD
Uranium isotopes[2]	NA	NA
Uranium (Total), micrograms/L	NA	TBD
Process-Related Organics[4] (mg/L)		
Total petroleum hydrocarbons-diesel	NA	TBD
Benzene	TBD	TBD

Parameter	AQL	AL
Ethyl benzene	TBD	TBD
Toluene	TBD	TBD
Total Xylene	TBD	TBD
Naphthalene	TBD	TBD
Octane	TBD	TBD

Note: The Permittee shall utilize the applicable analytical methods described in Table I 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.

AQL - Aquifer Quality Limit (as defined at Part II.F.2.d)

AL - Alert Level

TBD - To be determined and approved by the director for the POC well and observation wells required by EPA according to the final installation schedules for these wells. The final schedule for POC well, HC well, and OW installation will be subject to EPA review of ISR operations performance and monitoring data as operations proceed.

NA -Not applicable: Shall be measured and reported but no contingency level shall be established.

[1] Nitrate will be used only for calculation of cation/anion balance because of regional nitrate pollution and no nitrate used in processes.

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

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

[4] 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.

3. Baseline Data and Statistical Methods

As POC wells, outer OWs, and inactive HC wells at the southern and eastern wellfield boundaries are installed and prior to the commencement of injection at new mine blocks associated with those wells, the Permittee shall:

a. Collect baseline water quality samples and analyze for all Level l and Level 2 parameters such that accepted statistical methods can be applied to assign ALs and AQLs at all POC, outer OWs, and inactive HC wells at the southern and eastern wellfield boundaries. For Process-Related Organics (Level 2), two (2) months of data collection with nondetectable organic levels will be sufficient for background characterization.

b. Submit to the Director a report containing mean baseline concentrations, standard deviations, ALs, and federal AQLs, based on statistical methods used to establish ALs and AQLs, as described at Section 2.4 in Attachment P and Section 2.5.3.1.2.1 of Appendix I of this permit, or based on other methods approved by the Director, 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 the Director for the baseline data, action levels, and statistical approach defined at paragraph 3(b) of this Section F, above. The EPA response will be provided within thirty (30) days if the report is complete and satisfactory.

4. Water Quality Monitoring Schedule

The Permittee shall comply with the monitoring schedule in Table 3 at the five (5) POC wells and eleven (11) outer OWs, in accordance with the final installation scheduled for those wells, for the approximately twenty-three (23)-year Project operation and restoration life and the five (5)-year post-rinsing monitoring period:

Table 3. Monitoring Schedule for the POC and Outer Observation Wells during Project Life and Post-Rinsing Period

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

Note: Level 1 and Level 2 Water Quality Parameters are defined at Part II, Section F.2 in Table 1 and Table 2, respectively.

Note: The Quarterly Compliance Monitoring Tables (Level 1 parameters) for each POC and observation well are presented in Table P-3 and the Semiannual and Contingency Monitoring Tables (Level 2 parameters) for each POC and monitoring well are presented in Table P-4 in Appendix I of this permit. Refer to Tables P-3 and P-4 for water quality monitoring well schedules.

5. Hydraulic Control Monitoring Wells

External monitoring of the ISR process around the perimeter of the Project wellfield shall be conducted to verify hydraulic control. This monitoring of the oxide bedrock zone shall be performed using thirty (30) hydraulic control wells and twenty-two (22) paired OWs at the perimeter of the wellfield. Hydraulic control monitoring will entail using the OW pairs for head comparison and for verifying that the head gradient is inward, that is, from the outer OW toward the inner OW and wellfield. Head monitoring will be accomplished using pressure transducers placed in the OWs from which average daily head measurements will be recorded. In addition, the Permittee shall monitor specific conductance in the outer OWs to verify that hydraulic control is maintained and to detect any excursion in accordance with the approved procedures defined in paragraph 6.b, of this Section F. Fluids produced from the HC wells shall be monitored for specific conductance daily. The revisions to the installation and activation schedule, choice, and number of IMW, HC well, and OW locations to be monitored during the three stages of ISR and rinsing operations shall be subject to

EPA review and approval as ISR operations proceed in each mine block, as described at Section F.1.

6. Specific Conductance Monitoring

a. Prior to commencement of injection in new mine blocks, 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 measurements in the IMWs, outer OWs, and activated HC wells associated with the new mine blocks and in inactive HC wells at the southern and eastern wellfield perimeter prior to commencement of injection in the first activated mine block, in accordance with methods described in Attachment P in Appendix I. Where any conflict or inconsistency exists between Attachment P and the permit conditions, the permit condition shall supersede the language in Attachment P.

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

iii Receive written approval from the Director for the baseline data, proposed action levels, and proposed procedures. The EPA response will be provided within thirty (30) days if the report is complete and satisfactory.

b. During Project ISR and rinsing operations, the Permittee shall monitor specific conductance in the outer OWs on a daily basis. Specific conductance in IMW and HC well fluids shall also be monitored daily.

7. Injectate Solution (Lixiviant) 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 Table I 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 requirment 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 7(a) of this Section F, above, if the Permittee has received written approval from the Director for a change in the injectate solution, as detailed at Part II Section E.6. of this permit, and the list described in paragraph 7(a) of this Section F, does not include all organic constituents which are present or could be present in the raffinate pond. Monitoring for naphthalene and octane may be discontinued if not detected in the first six (6) monthly sampling events.

The Permittee shall measure inorganic constituents in the PLS and lixiviant at least once per month using applicable analytical methods described in Table I 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 plus strontium and thorium. The Permittee may request monthly monitoring be reduced to quarterly monitoring if the listed inorganics concentrations do no vary significantly during the first six (6) months of sampling. The requirment for monthly monitoring will be reinstated if concentrations vary significantly during quarterly sampling.

c. The Permittee shall modify the list of inorganic constituents described in paragraph 7(a) of this Section F in accordance with the requirements of Part II, Section E.6 of this permit.

8. Groundwater Elevation Monitoring.

Groundwater depths and elevations, measured in feet relative to mean sea level, in the POC, IMWs, and OWs shall be measured on a quarterly basis and reported in accordance with Part II, Section G.2.e of this permit.

9. 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.

10. 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. Lixiviant 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)	continuous	digital recorder

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 well and post-rinsing 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 Drinking Water Protection Section, or

ii. Written approval from the Regional Administrator 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 quarterly monitoring data.

b. A table and graph showing daily cumulative injection volumes and recovery volumes and the daily percent recovery to injection volume in the Project over the reporting period. The report shall identify any 24 hour periods in which the volume recovered is less than the minimum percent of volume injected and any contingency actions taken during the reporting period.

c. A table and graphs comparing daily average head measurements in the eleven (11) outer OWs surrounding the Project wellfield with the same measurements in the eleven (11) inner OWs and a calculation of the head gradients between OW pairs.

d. A table and graph showing results of the specific conductance measurements and depths in the outer OWs 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 increase that occurred, an evaluation of whether an excursion has occurred, and mitigating actions taken during the reporting period.

e. A table showing POC, IMWs, and outer observation well groundwater depths and elevations, analytical results, AQLs, 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 exceedances that occurred 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.7 (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 the 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 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.

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 block.

5. Submittal Address

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

U.S. Environmental Protection Agency, Region 9
Drinking Water Protection Section (WTR-3-2)
75 Hawthorne St.
San Francisco, CA 94105-3901

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 blocks during a 24-hour period is less than one-hundred-one (101) percent of the amount of fluid injected during the same 24-hour period:

i. adjust the flow rate for the recovery and/or injection wells and/or the HC wells to restore the percent of recovered fluid volume to at least one-hundred-one (101) 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 one-hundred-one (101) percent of the injected volume.

b. A loss of hydraulic control is deemed to occur when the amount of fluid recovered during a 48-hour period is less than one-hundred-one (101) percent of the amount of fluid injected during the same 48-hour 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 pair of OWs 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 0.01ft./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 inward flow ratio and head differentials may be adjusted during the ISR operation if warranted by specific conductance data from outer OWs or head data from OW-pairs and from POC and other monitoring wells, 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 for more than 48 consecutive hours, 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, recovery, and HC wells to reverse a confirmed loss of hydraulic control and excursion indicated by a specific conductance exceedance at an outer OW or until the amount recovered equals an amount sufficient to restore the ratio of fluid recovered to injected during the prior 72-hour period to a minimum of one-hundred-one (101) percent and restore all OW pair head differentials to at least 0.01 ft./ft. to verify an inward flow 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 loss of hydraulic control or the variance from the required recovery to injection ratio and the actions that were taken to correct the event.

2. Water Quality Exceedances at POC and outer observation wells

The following describes contingency plans to be followed after the verification of a federal AL or AQL exceedance in a POC or outer OW during the approximately twenty-three (23)-year operation and restoration life and during the five (5)-year post-rinsing 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 a federal AL listed in Table 1 or Table 2 of 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 the Director 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, the Director may require additional monitoring and/or action beyond those specifically listed in this permit.

b. In the event of an AQL exceedance during operational Project Life, rinsing, and post-rinsing monitoring period:

i. The Permittee shall collect a verification sample within five (5) days of becoming aware of an exceedance of a federal AQL listed in Table 1 or Table 2 of 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 the Director 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 AQL 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 AQL 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 AQL exceedance, or

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

v. Upon review of the report documenting the AQL exceedance, the Director 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 Table 1 of Part II.F.2 of this permit. If the constituent that exceeded an AL or AQL is one that is listed in Table 2 of Part II.F.2 but not in Table 1, the verification sample shall be analyzed for all constituents listed in Table 1 and only for constituent(s) from Table 2 that exceed the AL or AQL.

I. RESTORATION and PLUGGING & ABANDONMENT

Pursuant to 40 CFR Parts 146.10 and 144.12, the Permittee shall comply with the Wellfield Closure Strategy in Appendix F and the Plugging and Abandonment Plans in Appendix C in accordance with the schedule for aquifer 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 Plugging and Abandonment Plans and permit conditions, the permit conditions shall supersede the language in the Plugging and Abandonment Plans.

1. Closure and Plugging and Abandonment Plan

a. Constituents with primary MCLs: Within 60 days after completing copper recovery operations in the injection and recovery zone of a specific mine block, 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 to 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 constituents which do not have primary MCLs do not 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 copper recovery operations have been completed. During closure operations, the Permittee will cease injection of lixiviant 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 include rinsing to remove residual PLS, post-rinsing monitoring, and well abandonment, as described in the Wellfield Closure Strategy in Appendix F. After copper recoveries drop below the economic cutoff, ISR in each production block will be deemed complete and the block will be rinsed using fresh groundwater until applicable water quality standards are met. A three-step rinsing process will be implemented as follows:

1. Rinse three (3) pore volumes (based on a 3% fracture porosity of the orebody);
2. Rest for one (1) year; and
3. Rinse two (2) pore volumes.

The Permittee shall monitor the rinsing progress by analyzing fluids recovered from all recovery wells in the first mine block after rinsing Step 3. These data will then be used to determine the minimum number of sampled wells needed to confirm that rinsing has been successful in the rinsing and closure of subsequent mine blocks. The results of that evaluation shall be submitted for EPA review and approval. The wells to be retained for sampling during rinsing operations in subsequent mine blocks shall be identified and the locations of those wells shall be provided before closure of other wells in a mine block is approved by EPA.

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

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

When all individual rinse verification well concentrations within the injection and recovery zone of a specific mine block are below the

AQLs, rinsing operations for all wells within the mine block will be discontinued for thirty (30) days. At the end of the thirty (30)-day period, the wells shall be re-sampled and if Level 2 constituent concentrations remain below the AQLs 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 block. 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 approval. The wells shall be abandoned in accordance with the Plugging and Abandonment Plan (Appendix C) and the Wellfield Closure Strategy in Appendix F unless modified for individual well conditions.

2. Post-Rinsing Monitoring:

Monitoring at POC, outer 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 Wellfield Closure Strategy in Appendix F of this permit, the post-rinsing monitoring schedule at Part II. Section F.4 of this permit and the AQL exceedance contingency plan established in Part II, Section H.2, paragraph (b) of this permit. The post-rinsing monitoring schedule at Part II. Section F.4 may be extended beyond five (5) years, as described in the Wellfield Closure Strategy, if water quality standards are not met for five consecutive years at all closure verification wells and outer OWs, and EPA deems it necessary to ensure adequate protection of USDWs. The Permittee shall submit a post-rinsing notification and report, with documentation, to EPA within thirty (30) days following completion of the post-rinsing monitoring program.

J. OPERATIONAL AND POST-RINSING AUDITS

The permittee shall submit a groundwater flow model evaluation and updated report within six (6) months of the completion of the first year of operation for each of the three stages and every five (5) years thereafter for Stages 1 and 3 until mine closure. The schedule for these audits may be adjusted, depending on the progress of Stage 1, 2, and 3 operations, subject to EPA review and approval. 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 IMWs and 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). The model shall assess the performance of the operating mine blocks, rinsing of mine blocks, capture associated with hydraulic control wells, and any changes to the post-rinsing period required by this permit and recommend adjustments to the post-rinsing monitoring period based on updated groundwater flow modeling results. Simulation of the injection/recovery well performance may be included in the assessment of operating mine block performance if warranted by ISR operational performance and monitoring data.

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-three (23) year Project operation and restoration life and five (5) year post-rinsing 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-rinsing 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 Plugging and Abandonment Plan (Appendix C) and the Wellfield Closure Strategy (Appendix F) and consistent with 40 CFR §144.52(a)(7) and 40 CFR 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 the amount of $8,792,000 to guarantee aquifer restoration, groundwater monitoring, and plugging and abandonment activities for closure and post-closure. 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. The Closure Plan and detailed cost estimates for the Gunnison ISR Stage 1 Wellfield are provided in Attachment R-3 of the permit application, which is included in Appendix C.

b. The level and mechanism of financial responsibility shall be reviewed and updated 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.

Excelsior must provide estimated closure costs and updated financial assurance for Stage 2 and 3 operations before initiating drilling and ISR operations in those stages. Those cost estimates and the updated financial assurance mechanism, if necessary, must be provided and reviewed for acceptance by EPA in accordance with Part II.L and 40 CFR §144.52(a)(7), and 40 CFR Subpart F before Excelsior will be authorized to begin those operations.

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.

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 includes 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.