STATEMENT OF BASIS

KERR-MCGEE OIL & GAS ONSHORE, L.P.
NBU 921-331 SWD-B
UINTAH COUNTY, UT

EPA PERMIT NO. UT22330-10832

CONTACT: William Gallant
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-UIC
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (800) 227-8917 extension 312-6455

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Kerr-McGee Oil & Gas Onshore, L.P.
1368 South 1200 East
Vernal, UT 84078

on

February 10, 2015

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

NBU 921-331 SWD-B
2274 feet from the South Line, 918 feet from the EL, [NO QTR SEC] S33, T9S, R21E
Uintah County, Utah

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

PART II. Permit Considerations (40 CFR 146.24)

The U.S. Fish and Wildlife Service (USFWS) concluded its formal section 7 consultation with a letter and biological opinion (BO) dated February 17, 2015. This letter and BO is in regards to the proposed NBU 921-33I-B SWD injection well. The USFS concurs that this project may affect, but is not likely to adversely affect the Uinta Basin Hookless cactus (Sclerocactus wetlandicus). The USFWS also notes the following operator-committed conservation measures.

- Only water (no chemicals, reclaimed production water or oil field brine) will be used for dust abatement measures within Sclerocactus habitat.
- Dust abatement will be employed in suitable Sclerocactus habitat over the life of the project during the time of the year when Sclerocactus species are most vulnerable to dust-related impacts (March through August) - if applicable depending on timing of the project.
- All disturbed areas will be reclaimed with native plant species or seed mixtures.
- Equipment should be cleaned to remove noxious weeds/seeds prior to moving on site.
- Noxious weeds will be controlled using integrated pest management strategies (i.e., mechanical, chemical).

The USFWS documents within their BO that the Upper Colorado River Basin Endangered Fish Species Recovery Program (Recovery Program) and its actions adequately offset the effects to the four adversely affected fish species (Colorado Pikeminnow, Humpback Chub, Bonytail, and Razorback Sucker. Included in the Recovery Program was the requirement that a depletion fee would be paid. On July 8, 1997, the USFWS issued an intra-service BO determining that the depletion fee for average annual depletions of 100 acre-feet or less ae no longer required. Because the Recovery Program has made sufficient progress to the Reasonable and Prudent Alternative (RPA) to avoid jeopardy for the endangered fishes from impacts caused by depletions from the Upper Colorado River Basin, depletions of 100 acre-feet or less are now exempt from the depletion fee. The estimated water depletion for this project is 0.322 acre-feet per year. Therefore, the depletion fee for this project is waived.

The USFWS concludes that the Recovery Program serves as an appropriate conservation measure and adequately addresses effects to the species. Therefore, no additional conservation measures are needed to reduce impact from the proposed action. The EPA concurs with these determinations.

The Utah Division of State History (SHPO) in their letter of 3 June 2015 (Case number 11-1257) agreed with a “No Historic Properties” finding for this site.

The Utah State Trust Lands Administration indicated that no issues exist in relationship to historic properties at the proposed drilling location in an e-mail dated 23 April 2015. This e-mail is in regards to the proposed NBU 921-33I-B SWD injection well. The proposed location has been previously surveyed for the presence of cultural resources by Montgomery Archaeological Consultants (U-07-MQ-1437b, i, p, s) with a finding of no historic properties. The Trust Lands Administration endorses the results and recommendations of the cultural resources survey pertaining to the aforementioned well location and concurs with the finding of “No Historic Properties” Therefore, no additional conservation measures are needed to reduce impacts from the proposed action. The EPA concurs with these determinations.

Hydrogeologic Setting

General Geology

This is a general summary description of the geology in the area of the proposed NBU 921-33I-B SWD Well. The description begins with the Uinta Formation which outcrops at the surface and concludes with the Blackhawk interval of the lower Mesaverde Formation which is the deepest stratigraphic horizon commonly penetrated by production wells in the Greater Natural Buttes Field.

Uinta Formation: Surface to estimated 1,493 feet in the NBU 921-33I-B SWD well.

The Uinta Formation (Eocene) consists of alternating beds of light-gray calcareous mudstones and light-brown to brown siltstones and sandstones. Individual siltstone and sandstone beds are discontinuous, have limited areal extent (typically less than 40 acres) and are isolated from each other by low permeability calcareous mudstones. The Uinta Formation was deposited in fluvial and flood plain environments. The siltstone and sandstone beds were deposited in fluvial channels and are more abundant in the lower portion of the formation. The intervening calcareous mudstones were deposited in flood plain environments. The lower portion of the Uinta Formation is transitional into lacustrine deposits in the central portion of the Uinta Basin.

Green River Formation: Estimated 1,493' to 4,794' at the NBU 921-33I-B SWD location.

The Green River Formation (Eocene) is a complex mixture of clastics, carbonates and organic rich claystones deposited in an alluvial to lacustrine depositional system. A complex interfingering of alluvial, fluvial, marginal-lacustrine sediments was produced by significant lake level fluctuations caused by tectonic activity and climatic changes. The Green River Formation is subdivided into four members which in ascending order are: Douglas Creek Member, Garden Gulch Member, Parachute Creek Member and Evacuation Creek member.

• The Evacuation Creek Member directly overlies the Parachute Creek Member and is overlain by the Uinta Formation. The Evacuation Creek Member is composed primarily of light gray-green shale, tan marl and interbedded brown sandstones. The upper portion of the Evacuation Creek Member contains the informally named Birds Nest aquifer.

> The Birds Nest was deposited during a regressive lacustrine phase. The lake waters in the deeper portion of the lake became concentrated in salts, primarily sodium bicarbonate during this regressive phase. Nahcolite was deposited in the marl sediments in the form of nodules as the salty waters were expelled during early diagenesis. Percolating ground waters subsequently dissolved the nahcolite nodules to form the Birds Nest Aquifer in the uppermost portion of the Green River Formation. The Birds Nest Aquifer covers an area of approximately 1,200 square miles in portions of 48 townships (Twps 7-12, Rgs. 18-25E Uintah County Utah. The Birds Nest Aquifer in the NBU 921-33I area contains brine with TDS in excess of 25,000 ppm TDS.

• The Parachute Creek Member directly underlies the Evacuation Creek Member and consists of a thick succession of dark brown, dark gray, light green and red shales with occasional fine-grained sandstones. The shales were deposited in the deeper portions of the open lacustrine environment and the sandstones were deposited in the shallower marginal lacustrine environments. The Parachute Creek Member contains the most organic rich oil shales, in the Mahogany Oil Shale zone.

• The Garden Gulch Member directly underlies the Parachute Creek Member and consists primarily of dark colored shales and very fine grained sandstones. The Depositional environments and facies were similar to the Douglas Creek Member, but dominated primarily by lacustrine processes. Shale intervals are thicker than those of the Douglas Creek member and organic rich.

• The Douglas Creek Member consists of light gray alternating beds of calcareous sandstone and dark gray to brown brittle shale with minor amounts of oil shale, dolomite and limestone. Deposition took place in a marginal lacustrine environment. Three major facies are recognized in the Douglas Creek Member: Fluvial deltaic, mudflat-lagoon, and lacustrine barrier-beach. The fluvial-deltaic deposits contain channel sandstones that fine upwards from medium to very coarse grained sands at their base to very fine grained sands interbedded with siltstones and shales at the top. The intra channel deposits consist of floodplain shales and claystones.

The mudflat-lagoon sediments are characterized by interbedded shale, and siltstone with calcareous and dolomitic mudstones. The sediments were deposited in low energy areas protected from waves and isolated from major clastic input.

The lacustrine barrier-beach deposits are characterized by upward coarsening sequences. The lower portion of the sequences consist of gray to dark gray, laminated silty shale, which grade upward into light gray, very fine to fine grained sandstone in the upper part of the of the sequence. Ooids and carbonate coated quartz are also common in the upper portions of the sequences.

Wasatch Formation: Estimated 4,794' to 7,597' at the NBU 921-33I location

The Wasatch Formation (Paleocene – Eocene) consists of poorly sorted variegated mudstones and siltstones in shades of red, green and gray interbedded with beds and lenses of sandstone, conglomerate and minor carbonate deposits. Sandstones are very light brown to gray, irregularly bedded and are fine to medium grained. Conglomeratic sandstones often containing black chert and varicolored quartzite pebbles commonly occurring at the base of sand bodies. Wasatch deposition took place in mixed fluvial to lacustrine depositional environments. The Wasatch Formation interfingers with and in places is time equivalent to the Green River Formation. The Wasatch sandstones in the NBU 921033I area are productive of natural gas and condensate.

The Wasatch Formation water TDS value at the NBU 921-33I location is estimated to be 22,000 ppm. This TDS value is derived from mapping representative produced Wasatch water samples. The closes representative produced Wasatch water sample is 23,829 ppm from the NBU 261 (359' FNL, 616' FEL, Sec 31, T19S, R21E) is located 2,770' north of the proposed NBU 921-31I-B SWD location.

Mesaverde Formation: Estimated 7,591' to 10,092' at the NBU 921-33I location

The Mesaverde Formation (Upper Cretaceous) is the uppermost interval of the Mesaverde Group. The Mesaverde Formation consists of mostly gray to brown, well sorted, sandstone interbedded with greenish-gray silty shale. The sandstones are typically well sorted, medium grained, cross bedded and thin to thick bedded and are locally conglomeratic. The lower portion of the Mesaverde Formation often contains coals. Mesaverde deposition took place in continental fluvial to flood plain depositional environments.The Mesaverde sandstones in the NBU 921-33I are productive of natural gas and condensate.

The Mesaverde Formation water TDS at the NBU 921-33I –B SWD location is estimated to be 22,700 ppm. This TDS value is based on a representative Mesaverde water sample recovered from NBU 921-33I, 50’ to the southeast of the proposed NBU 921-33I-B SWD.
The Mesaverde water sample from the NBU 921-33I had a TDS value of 22,741 ppm.

Castlegate Sandstone: Estimated 10,092’ to 10,367’ at NBU 921-33I location

The Castlegate Sandstone (Upper Cretaceous) is the lowermost interval of the Mesaverde Group. The Castlegate Sandstone consists of brown to very light gray sandstone interbedded with sparse gray siltstone and shale. The sandstones are typically wells sorted, range from fine to coarse-grained with some conglomerate beds, quartzose, laminated to massive bedded with cross bedding. Castlegate sandstones are continuous and correlative in the Greater Natural Buttes area. Castlegate deposition took place in continental fluvial conditions in a series of braided river systems.

Castlegate Sandstone water samples are limited because the Castlegate is water wet in the Greater Natural Buttes area so it has not been commonly tested in production wells. The Castlegate Sandstone has an average TDS value of approximately 20,000 ppm based on limited Castlegate produced water samples in the area.

Blackhawk Formation: Estimated top at 10,367’ at the NBU 921-33I SWD location

The Blackhawk Formation (upper Cretaceous) is the lowermost interval of the Mesaverde Group. The Blackhawk Formation consists of light brown and brownish gray sandstone sequences interbedded with shaley siltstone, shale and carbonaceous shale. Sandstones are quartzose, well sorted, fine to medium grained and thin to medium bedded. Sandstone sequences grade upwards from shaley siltstone at the base to fine to medium grained sandstone at the top of the sequence. Blackhawk sandstone sequences are correlative and continuous over several miles in the Uinta Basin. Blackhawk deposition took place in a series of foreshore to offshore marine environments. Sandstone deposition took place in higher energy foreshore to shoreface environments, with shale deposition taking place in low energy offshore environments. The Blackhawk sandstones are productive of natural gas and condensate ¾ mile to the north of the NBU 921-33I – B SWD location in Section 27, T9S, R21E.

The Blackhawk Formation is the deepest formation penetrated in the immediate area of the NBU 921-33I-BSW. Produced water from the Blackhawk sandstones has an average TDS value of approximately 30,000 ppm base on limited Blackhawk produced water samples in the area.

TABLE 2.1
GEOLOGIC SETTING
NBU 921-331 SWD-B

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta Formation	0	1,493		siltstone, sandstone and shale
Green River/ Parachute Creek	1,493	3,150		Siltstone and shale
Lower Green River	3,150	4,800		Dolostone and sandstone
Wasatch Formation	4,800	7,600		Sandstone
Mesaverde Formation	7,600	9,750		

Proposed Injection Zone(s) (TABLE 2.2)
An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

TABLE 2.2
INJECTION ZONES
NBU 921-331 SWD-B

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Green River/ Birds Nest Aquifer	1,665	1,950	> 25,000	0.732		N/A

*** C - Currently Exempted**

E - Previously Exempted
P - Proposed

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

TABLE 2.3
CONFINING ZONES
NBU 921-331 SWD-B

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Green River Formation	Siltstone and shale	1,493	1,665
Green River Formation	Shale	1,950	2,041

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
NBU 921-331 SWD-B

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta Formation	Light-gray calcareous mudstones and light brown to brown siltstones and sandstones	0	1,457	3,000 - 10,000

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
NBU 921-331 SWD-B

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
J-55	7.00	3.50	0 - 1,600	-
J-55	8.75	7.00	0 - 1,645	0 - 1,645
J-55		14.00	0 - 40	0 - 40

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)
The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices
The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
NBU 921-33I	Producer	No	9,695	1,690	TBD
NBU 921-33J	Producer	Yes	9,351	260	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review
Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit, if necessary, as APPENDIX F and become binding on the permittee.

PART V. Well Operation Requirements (40 CFR 146.23)

Standard practice in EPA Region 8 has been to limit the Birds Nest Aquifer (BNA) salt water disposal wells in the Uinta Basin to 300 psi surface pressure. The EPA has elected to lower the calculated MAIP in Table 5.1 below to 300 psi to remain consistent with similar EPA regulated injection wells. The BNA is typically on a vacuum and to date, the 300 psi injection pressure limit has never been reported as a problem.

TABLE 5.1
INJECTION ZONE PRESSURES
NBU 921-331 SWD-B

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Green River/ Birds Nest Aquifer	1,665	0.732	300

Approved Injection Fluid
The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

Injection Pressure Limitation
Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

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

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation
Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity. The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

The AOR well fully penetrates the Birds Nest Aquifer and is only 50 feet from the proposed injector. It is apparent from evaluating the CBL of the adjacent producing gas AOR well (NBU 921-33I) that there is poor quality cement across the upper confining layer. An outer casing overlaps the Birds Nest injection zone, however, no CBL log is available for evaluation and it is uncertain as to how much cement loss to the adjacent Birds Nest Formation has occurred.

The requirement is to provide annual temperature logging of this AOR well using EPA protocols and monitor the pressure between the inner and outer casing and make observations of the area on the backside of the outer casing for leakage at the surface during water injection activities in the adjacent proposed injection well (NBU 921-33I-B). This approach is intended to evaluate the need for a corrective action on the AOR well and if leakage of injectate is travelling upwards into shallow USDWs in the area.

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

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Bond Rider No.10 received April 6, 2016

Evidence of continuing financial responsibility is required to be submitted to the Director annually.