STATEMENT OF BASIS

Kinder Morgan CO_2 Company LP
HWD-1 (Hovenweep 1)
Montezuma County, Colorado

Class I Non-Hazardous Waste Disposal Well
CO10787-00053

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This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in CO10787-00053 (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 (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs. In accordance with 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 or 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. Regulations specific to Colorado injection wells are found at 40 CFR § 147 Subpart G.

Upon the Effective Date when issued, the Permit authorizes the operation of injection well or wells so that the injection does not endanger USDWs. This Permit is issued for 10 (ten) years from the Effective Date, until it expires under the terms of the Permit, or unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41.

PART I. General Information and Description of Project

Kinder Morgan CO_2 Company LP
17801 U.S. Hwy 491
Cortez, Colorado 81321

hereinafter referred to as the "Permittee," submitted an application for a UIC Program permit for the following injection well or wells:

HWD-1 (Hovenweep 1)
515' FEL & 300' FNL, Section 9, T38N, R18W
Montezuma County, Colorado

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by EPA to be complete.

Project Description

An application was received from the Permittee on February 6, 2019. The application was submitted to reauthorize injection activities for an additional ten [10] years through a permit in accordance with 40 CFR Sections 124.5 and 144.39. The first Permit for the HWD-1 well was issued on February 6, 1987, with an effective date on March 8, 1987, due to changes made to the Final Permit as a result of the receipt of comments on the draft.

The Permittee is involved in the extraction of oil and gas from subsurface reservoirs. The Permittee has also determined that the naturally occurring carbon dioxide (CO_2) can be produced and economically used as an enhanced oil recovery agent.

The CO_2 source field is leased under provisions of standard oil and gas leases from the Bureau of Land Management (BLM) and private parties. Existing production operations (from approximately 30 wells in the Leadville and Ouray Formations) result in the recovery of naturally occurring gases consisting of 98.37% carbon dioxide (CO_2), 1.38% nitrogen (NO_2) and 0.25% methane (CH_4). These produced gases are piped to a cluster facility where free water is separated out using gravity separation. The liquid and vapor CO_2 are treated with Diethylene Glycol (DEG) and transported to a central facility where the CO_2 is vaporized and the liquid water and DEG are separated. The DEG and the waste stream of produced water are disposed into the Leadville and Ouray Formations.

This Permit allows for the continued non-commercial injection of the process produced, nonhazardous waste water into the subject disposal injection well. This process produced, nonhazardous waste water originates from the Leadville Formation in the McElmo Dome and Doe Canyon Fields.

PART II. Permit Considerations (40 CFR § 146.14)

Hydrogeologic Setting

The Hovenweep (HWD-1) well is located on the eastern flank of the Colorado Plateau physiographic province. This province is characterized by thick sequences of sediments which have been structurally stable since Precambrian time. Major geologic events, in more recent time (Tertiary), include the intrusion of laccolithic stocks such as the Sleeping Ute Mountain. This volcanic/plutonic rock body provided the heat source that caused the Leadville Limestone to alter and produce CO_2 gas, which accumulated in economic quantities in the McElmo Dome area.

Quaternary deposits containing ground water have been identified in the reports referenced or included in the Administrative Record. However, these surficial deposits are normally less than 20 feet thick, except along valley bottoms, and no water wells utilize Quarternary deposits in the area, (Romero, 1985). “Dakota Sandstone, Burro Canyon, and Salt Wash Member strata are known aquifers in other areas and probably have water yielding properties in Section 16. The Junction Creek and Entrada Sandstones are known aquifers, and a well about 3 miles to the east in Section 13 probably taps one or both of these sandstones. Geologic units below the Entrada and above the Hermosa (Navajo, Windgate, Chinle) yield small quantities to water wells in other areas, but nothing is known of their yielding potential in the vicinity of the McElmo Dome Unit application”, (Romero, 1985).

The Geological Setting data, formation names, lithology descriptions and depths, were obtained from EPA’s 1987 Fact Sheet. The data for the base of the Ouray and depths of the Devonian (Elbert) and Undifferentiated Cambrian Formations were obtained from additional information submitted by the permittee. The total dissolved solids (TDS) values and zone types have been obtained from the permit application, additional data submitted by the permittee, and the reference document Ground Water Atlas of the United States, Segment 2.

TABLE 2.1
Geologic Setting

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS mg/l
Quaternary	Alluvial sands and gravels, loess, colluvium windblown sands	0	570	357 – 3790
Morrison	Light gray to pink sandstone and green or red mudstone	570	760	516
Bluff	Gray to buff Sandstone	760	1025	<10,000
Summerville	Red, sand mudstone, red sandstone and minor chert	1025	1143	<10,000
Entrada	Light buff, reddish brown or salmon colored fine grained sandstone	1143	1248	<10,000
Carmel	Reddish brown sandy siltstone and silty sandstone	1248	1265	<10,000
Navajo	Buff to pale orange cross bedded sandstone	1265	1398	2,760
Kayenta	Reddish sandstone and interbeds of red or green mudstone	1398	1440	<3,000
Wingate	Sandstone	1440	1950	<3,000
Chinle	Siltstone, sandstone, and mudstone	1950	2656	<10,000
Moenkopi	siltstone and sandstone	2656	2705	--

Cutler	Sandstones and Conglomerates	2705	4482	4,957-7,909; 38,000 – 78,000
Honaker Trail (Hermosa Group)	Sandstones, limestones, and shales	4482	5510	6730 – 381,436
Paradox	Interbedded salt, anhydrite, dark colored dolomites and black shale	5510	7970	No water
Pinkerton Trail	Light gray limestones and gray to gray green shales, siltstones and sandstones	7970	8116	No water
Molas	Interbedded red siltstones, sandstones, light colored limestones and varicolored shales	8116	8220	No water
Leadville - Ouray	Limestones and dolomite	8220	8630	78,727
Devonian (Elbert)	Shale, limestone, sandstone, and siltstone	8630	8980	15,200
Undifferentiated Cambrian	Siltstone, dolomite, and shale	8980	9400	182,246
Precambrian	Crystalline	9400	Basement	**--**

Note: "**--**" indicates no data available.

Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone(s) 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.

The Leadville/Ouray Formation water quality is quite variable. The TDS concentration ranges from 3000 milligrams per Liter (mg/l) to over 100,000 mg/l depending where the water sample is taken. The lower TDS values are drawn from above the gas-water interface, where the water is in vapor form and drops out as condensation, with the change in pressure and temperature when the gas is produced. The higher TDS concentrations come from below the gas-water interface where "free water" is occurring. The injection zone, in the permit application, was shown to have a TDS concentration of 35,350 mg/l. The injected fluid has a TDS concentration of 3,155 mg/l.

The Leadville Formation's hydrogeologic parameters include porosity, 8%; permeability, 2.7 millidarcy (md); pore pressure, 2,500 pounds per square inch (psi); fracture pressure, 4,330 psi; bottom-hole pressure, 3,220 psi (while injecting @ 3 barrels per minute); bottom-hole temperature, 180 F.

The gross permitted injection zone will be from the top of the Leadville at 8,220 feet to 8,630 feet in the Ouray. The Hovenweep has open perforations in the intervals of 8,480 – 8,534 feet. Perforations were squeezed at the completion of the well in the interval of 8,298 – 8,448 feet. The injection zone has been extended to the base of the

Cambrian Formation and top of the lower confining zone, Precambrian Formation. The Devonian Elbert and Cambrian Formations have been added as injection zones because there is no isolation between the four injection formations. Both the Devonian Elbert and Cambrian formations exists below the total depth of the well. Literature and available water quality data indicates that the formations may not be a USDW.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Porosity	Exemption Status
Leadville - Ouray	8220	8630	3.5 - 25%	NA
Devonian Elbert	8630	8980	--	NA
Cambrian	8980	9400	--	NA

Notes: * depths are approximate values at the wellbore.
"--" indicates no data available.

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

The Pennsylvanian "red bed" Molas Formation comprises the upper confining zone. This formation was evaluated by electric logs to estimate its petrophysical properties. These logs included a Borehole Compensated Sonic Log, a Compensated Neutron Log, a Formation Density Log, a Dual Lateral Log and microlaterolog-microlog. The interpretation of these logs showed the formation to be approximately 114 feet thick. The shales and siltstones of the Molas Formation have apparent log porosity but are impermeable. The limestone intervals are tight, with porosity less than 2 percent.

Other shale formations between the injection zone and the lowermost possible USDW include the Cutler Formation, the Moenkopi Formation and the Chinle Formation. These three units are considered redbeds and have low permeabilities. The Chinle Formation is 706 feet thick, the Moenkopi Formation is 49 feet thick and the Cutler Formation is 1777 feet thick. Calculations of TDS concentrations using resistivity logs have shown the Chinle and Cutler Formations not to be USDWs, although they are water bearing and produce water elsewhere in the region.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Lithology
Molas	8116	8220	Interbedded red siltstones, sandstones, light colored limestones and varicolored shales
Precambrian	9400	Basement	Shale, limestone, sandstone, and siltstone

Note: * depths are approximate values at the wellbore.

Underground Sources of Drinking Water (USDWs)
Aquifers or the portions thereof which 1) currently supply any public water system or 2) contains a sufficient quantity of ground water to supply a public water system and currently supplies drinking water for human consumption or contain fewer than 10,000 mg/l TDS, are considered to be USDWs.

In the vicinity of the HWD-1 injection well, the base of the lowermost USDW is not definitively known. The available information reviewed by the operator suggests that the base of the usable USDW is likely associated with the base of the Mesozoic Sandstone Aquifer which generally coincides with the base of the Upper Triassic Wingate Sandstone. Per personal communication by the Permittee with a representative of the Colorado Department of Natural Resources, potential aquifers in the McElmo Dome Area include: Surficial deposits, the Dakota and Burro Canyon Formations, Saltwash member of the Morrison Formation, the Junction Creek and Entrada Sandstone and possibly the Chinle Formation.

There are additional formations in the area that could also be considered USDWs but are unknown because of the lack of data near the HWD-1 well. Based upon information submitted in the application, the Hermosa Group (Honaker Trail Formation) contains a TDS concentration ranging from 6,730 to 381,436 mg/L, and an average 202,700 mg/l, based on 23 samples from wells. The Honaker Trail may potentially be the base of USDWs in the area, but no water quality data is available to confirm this analysis. The Cutler and Rico Formations have aquifer potential, but definitive data are lacking.

USDWs are protected by cement behind pipe (surface and/or long string casing) from the surface to a depth of 2873 feet. Cement behind pipe of the surface casing extends from the surface into the Cutler Formation to a depth of 2873 feet. Cement resumes in the longstring casing from a depth of 4875 ft to the depth of 8020 feet. Confining geology of the Molas, Paradox Salts (approximately 1700 feet thick), Pinkerton trail, and Honaker Trail Formations confine injectate to the injection zones and protect upper USDWs by preventing the movement of fluids (contaminants) into USDWs in the area.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft
Quaternary	Alluvial sands and gravels, loess, colluvium windblown sands	0	570
Morrison	Light gray to pink sandstone and green or red mudstone	570	760
Bluff	Gray to buff Sandstone	760	1025
Summerville	Red, sand mudstone, red sandstone and minor chert	1025	1143
Entrada	Light buff, reddish brown or salmon colored fine grained sandstone	1143	1248
Carmel	Reddish brown sandy siltstone and silty sandstone	1248	1265
Navajo	Buff to pale orange	1265	1398

	cross bedded sandstone		
Kayenta	Reddish sandstone and interbeds of red or green mudstone	1398	1440
Wingate	Sandstone	1440	1950
Chinle	Siltstone, sandstone, and mudstone	1950	2656
Moenkopi	Siltstone and sandstone	2656	2705
Cutler	Sandstone and conglomerates	2705	4482
Honaker Trail	Sandstone, limestone and shale	4482	5510

PART III. Well Construction (40 CFR § 146.12)

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

Casing and Cement
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 fluid containing any contaminant into USDWs. Well construction details for the injection well(s) are shown in TABLE 3.1.

To protect shallow USDWs when drilling the surface hole, the Permittee is limited to drilling with air or mud made with water containing no additives and no more than 3,000 mg/l TDS, unless waived by the Director.

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

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Conductor	17.5	13.375	0-50	0-50
Surface	12.25	9.625	0-2,873	0-2,873
Production/Longstring	8.75	7	0-8,020	4,875-8,020
Liner	6.125	4.5	7,827-8,581	7,827-8,581
Tubing	N/A	2.875	0-8,167	N/A

Well Siting
By definition, Class I wells must inject beneath the lowermost formation containing, within one-quarter mile of the well bore, a USDW.

Injection Tubing and Packer
The tubing and packer are designed to prevent injection fluid from coming into contact with USDWs. Specifically, 40 CFR 146.12(c) requires that all Class I wells, except those municipal wells injecting non-corrosive wastes, inject fluids through tubing with a packer set immediately above the injection zone.

The permit requires that injection tubing be installed from a packer up to the surface inside the well casing and allows the packer to remain at 8,090 feet in the existing well construction. The top of the injection zone is 8,220 feet, and the packer placement is 30 feet higher than the typical allowance for placement of a packer within 100 feet of the injection zone. The Permittee requested that the packer remain in its existing configuration due to concerns that movement of the packer may result in damage to the well because of the length of time it has been secured in its existing location.

As described in Part II above, the base of the lowermost USDW occurs at a depth as deep as 5,510 feet and there are multiple formations with confining characteristics separating the injection zone from the base of the lowermost USDW. The existing packer placement is well below the base of the lowermost USDW and does not allow injected fluid to directly contact the portion of the casing adjacent to the lowermost USDW. As a result, the existing packer placement is reasonably consistent with the construction requirement contained in 40 CFR 146.12(c) and is protective of USDWs. In addition, testing requirements contained in Appendix B of the permit will ensure that the well maintains Part I and II Mechanical Integrity (MI), as defined in Part V below.

Tubing-Casing Annulus
The tubing-casing annulus (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 non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Device

To fulfill Permit monitoring requirements and provide access for EPA inspections, sampling and monitoring equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the MAIP is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA, and surface casing-production casing (bradenhead) annulus; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line; and 5) continuous recording devices to monitor injection pressure, flow rate, volume, pressure on the annulus between the tubing and the long string of casing, and the bradenhead pressure.

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

Well Injection and Seismicity

If an event is detected within two miles of the wellbore, the Permittee will immediately cease injection and report the event to EPA within 24 hours. The Permittee will report all events within 50 miles radius of the wellbore and provide a summary in the seismic events in the quarterly reports.

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

Area of Review (AOR)
Permit permittees are required to identify the location of all known wells within the AOR which penetrate the lowermost confining zone, which is intended to inhibit injection fluids from the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (¼) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (¼) mile for the circumscribing area may be

used.

The one quarter (¼) mile radius around the HWD-1 well used for the AOR is considered to be adequate. No non-freshwater artificial penetrations are identified within the AOR, as indicated by the Colorado Oil and Gas Conservation Commission online database viewer. One water well was identified in the AOR based on information available from the Colorado Division of Water Resources online database (2018). The water well (State ID number 258267) is associated with a rural residence located approximately 0.2 miles south of HWD-1.

No surface water bodies, springs, mines (surface and subsurface), quarries, or faults, were identified within AOR for HWD-1. One rural residence is located within the AOR, based on aerial imagery dated 10-12-17 available from Google Earth (2018) and is indicated on the Figure B.2. The residence is located approximately 0.2 miles to the south. No additional structures were noted in the AOR for HWD-1.

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

No corrective action is required at this time as EPA's evaluation did not identify migration pathways that would impact USDWs within the AOR.

PART V. Well Operation Requirements (40 CFR § 146.13)

Mechanical Integrity (40 CFR § 146.8)
An injection well has MI if:

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

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI as required in APPENDIX B Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating internal (Part I) and external (Part II) MI are dependent upon well and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

Renewal:
A successful internal Part I Mechanical Integrity Test (MIT) is required no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer, or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost MI, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

Internal (Part I) MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. Additional guidance for Internal (Part I) MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Demonstration of External (Part II) MI is required and will be repeated no less than five years after the last successful MIT. The External MIT will be demonstrated by using the results of a temperature log. Temperature logs will be run at least once every five (5) years after the last successful demonstration of Part II MI.

Injection Fluid Limitation
Injected fluids are limited to non-hazardous industrial fluids.

Injected fluids are limited to

a) spent sulfamic acid (2-8%) neutralized to a pH of 5 to 9 with soda ash or baking soda. This solution will also include a surfactant, a corrosion inhibitor and ammonium bifluoride;

b) acetic acid;

c) diethanolamine (DEA);

d) coolant drain-off (50% water, 50% diethylene glycol);

e) associated treatment chemicals, (e.g., antifreeze, corrosion inhibitor, and bacteria inhibitor);

f) potassium permanganate in potable water;

g) diethylene glycol;

h) produced/processed fluids; and

i) any non-hazardous fluids associated with field and plant development, operation and maintenance.

Prior to adding a new source, a fluid analysis sample must be provided for any new source that was not previously characterized. A new source may include fluids from a new formation, a new portion of the field, non-commercial fluids from another operator, or that are chemically dissimilar from fluids that are already injecting into the well. The list of analytes is found in APPENDIX D of the Permit “WITHIN 30-DAYS OF AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE”. As a result of the new sample analysis, the MAIP may need to be recalculated.

Volume Limitation
Injection volume is limited to the total volume specified in APPENDIX C of the Permit.

There is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the Maximum Allowable Injection Pressure (MAIP).

Injection Pressure Limitation
40 CFR § 146.13(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the injection zone.

The calculated MAIP described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition. Except during stimulation approved by the Director, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

The **MAIP** allowed under the permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the rock formation to fracture. This equation, as measured at the surface, is defined as:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

Where, FG is the fracture gradient in psi/ft
SG is the specific gravity
D is the depth of the top perforation in feet or top of the injection zone

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.
- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well or top of the injection zone.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

$$\mathbf{MAIP} = \mathbf{FP} + \text{friction loss (if applicable)}$$

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests, or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG annually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zone(s). However, it may be that the condition of the well may also limit the permitted MAIP. When external (Part II) MIT demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful external (Part II) MIT and not the calculated MAIP.

TABLE 5.1 provides an estimated formation fracture pressure based on the information submitted with the application. The permitted MAIP will be recalculated with the information submitted to obtain the authorization to commence injection.

TABLE 5.1
Injection Zone Fracture Pressure

Formation Name or Stratigraphic Unit	Depth (ft)	Specific Gravity	Fracture Gradient (psi/ft)	Friction Loss (psi)	Estimated Formation FP (psi)
Leadville - Ouray	8220	1.010	0.56	--	856
Devonian Elbert	8630	--	--	--	--
Cambrian	8980	--	--	--	--

Note: "--" indicates no data available.

The permittee has previously performed a step rate test that demonstrates no breakdown pressure observed from 0 to 1000 psig, and 0.56 psi/ft was the resulting conservative fracture gradient. No extension or propagation of fractures was observed from test data. A previous test was performed at the MWD-1 well and information applied to the HWD-1 well which is incorporated into Table 5.1. A step rate test will be performed at the HWD-1 well to verify the fracture gradient and formation pressure. This test will be performed in coordination with the annual 2021 Pressure Fall Off Test for the HWD-1. Both surface and bottom hole gauges will be used during this test and friction loss data will be collected.

The HWD-1 well is not completed in the Devonian Elbert and/or Cambrian Formations, and as a result, no fracture data was identified for these formations. A step rate test will be required to determine the fracture gradient if the well is recompleted to include perforations in the Devonian Elbert and/or Undifferentiated Cambrian Formations.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Annual Pressure Falloff Test (40 CFR § 146.13(d)(1))

The pressure falloff test is required for Class I operations and must be performed at least once every twelve (12) months for the purposes of monitoring pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

Annual monitoring of the pressure buildup in the injection zone includes a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

Injection Well Monitoring Program

Continuous monitoring of injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection, annulus, and bradenhead pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and bradenhead and annular pressure is required to be reported as part of the Quarterly Report to the Director.

Reporting Requirements
Quarterly, the Permittee must analyze a sample of the injected fluid for parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA as part of the Quarterly Report to the Director. Any time a new source is added, a fluid analysis must be provided of the injection fluid that includes the new source as discussed above, in PART V Injection Fluid Limitation.

Instantaneous injection pressure, injection flow rate, injection volume, bradenhead and TCA pressures must be recorded continuously. Each month's minimum, maximum and averaged values of these parameters and the cumulative fluid volume is required to be reported as part of the Quarterly Report to the Director.

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

Plugging and Abandonment Plan
Prior to abandonment, the well must 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 must 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 must be verified by tagging. A minimum 50 ft. surface plug must be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) 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(a)(7))

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 will show evidence of such financial responsibility to the Director by the submission of completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,
(b) a letter of credit with a standby trust agreement,
(c) a fully funded trust agreement, OR
(d) a financial test and corporate guarantee.

The Director 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. The Permittee, may also upon written request provide an alternative demonstration of financial responsibility.

If a financial test is provided, evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

EPA will ensure that issuance of this Permit is in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act, the Endangered Species Act, and Executive Order 12989 (Environmental Justice), before a final permit decision is made.

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. EPA has determined that a decision to issue a Class I injection well permit for authorization of injection into the HWD-1 (Hovenweep 1) well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

This re-issued permit allows the Permittee to continue injection into the HWD-1 well. No additional work or disturbance of any properties is anticipated. The Colorado State Historic Preservation Officer submitted a letter dated February 14, 2012, "Proposed Kinder Morgan's nearby Injection Wells HWD-2, MWD-1, and DWD-1, Montezuma and Dolores Counties, Colorado (CHS #61375)." The Colorado SHPO concurs with a finding of no historic properties affected (rather than no adverse effect) was appropriate for the proposed projects.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. EPA has determined that a decision to re-issue a Class I permit for continued authorization of injection into the HWD-1 (Hovenweep 1) well constitutes an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402).

This is a re-issue permit to continue existing operations. Therefore, there are no anticipated surface disturbances expected to affect any endangered species and/or their habitat. The Fish and Wildlife Service has reviewed data submitted by EPA regarding the Permittee's other wells located in the same field and concurred that no adverse impacts were expected to threatened and endangered Species and habitat in the proposed area. The wells previously evaluated were the YWD-1 and MWD-1 wells which have similar operations and operate in the same field as the HWD-1 well. The HWD-1 is similar to the YWD-1 and MWD-1 wells because they have operated since the 80s, have established infrastructure (pipes, roads, and well pads), and the same source of wastewater. No additional digging or surface disturbance activities or change in operations are planned for this project. Also, no additional treatment requirements will be implemented and no extra lighting is required.

Executive Order 12898
On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." EPA has concluded that there may be potential EJ communities proximate to the Authorized Permit Area. The primary potential human health or environmental effects to these communities associated with injection well operations would be to local aquifers that are currently being used or may be used in the future as USDWs. EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. EPA has concluded that the specific conditions of UIC Permit Number CO10787-00053 will prevent

contamination to USDWs, including USDWs which either are or will be used in the future by communities of EJ concern. These USDWs could include the aquifer within the proposed injection zone, in which case, injection would only commence if the aquifer is exempted and thereby no longer protected under the SDWA. The UIC program will be conducting enhanced public outreach to EJ communities by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.