# STATEMENT OF BASIS

**Wesco Operating, Inc**
**Riverton East 36-3**
**Wind River Indian Reservation**

Class II Salt Water Disposal Well
WY20673-03091

***CONTACT:*** Christopher Brown
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6669
Email: Brown.Christopher.T@epa.gov

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 WY20673-03091 (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 Indian country injection wells in Wyoming are found at 40 CFR § 147.2553.

The Permit is issued for the operating life of the injection well unless terminated for reasonable cause under 40 CFR § 144.40 and can be modified or revoked and reissued under 40 CFR § 144.39 or § 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).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to an approved state or tribal program, unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a tribal or state permit.

## PART I. General Information and Description of Project

Wesco Operating, Inc
120 South Durbin, P.O. Drawer 1706
Casper, Wyoming 82601

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

Riverton East 36-3
1,414 feet from the east line & 1,414 feet from the south line, Section 36, T 1 North, R 5 East
Fremont County, Wyoming

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

The Riverton East 36-3 Class II injection well has operated since October 1971 and was authorized by rule as part of the EPA administered Underground Injection Control (UIC) program on the Wind River Indian Reservation, which became effective on November 25, 1988. This authorization will expire upon the effective date of this permit under 40 CFR Sections 144.21(a); 144.21(b); 144.21(c)(9); 144.31(c)(1); and 147.2553.

The Riverton East 36-3 well injects fluids produced from wells in the same field. This fluid (i.e., oil and water) comes into a "Gunbarrel" type separator. The oil is routed to two (2) 400-barrels of steel tanks and is sold. The produced water from the Gunbarrel separator is routed to four (4) 400-barrels steel tanks which are equalized through a piping system between the tanks. A charge pump takes the water from the tanks and pushes it through a 100 micron filter and into the suction end of a Tri-plex (National-Oilwell T165-5H plunger type) pump. The triplex pump discharge is routed directly to the injection tubing in the Riverton East 36-3 water disposal well. A packer is installed in the well to isolate the tubing from the annular space above the packer. The pump is kicked on/off by means of a hydrostatic level controller (Murphy Switch). This switch also shuts the pump down if the filter gets plugged off. A high pressure kill switch is used to shut the pump down before the injection pressure exceeds the well's maximum allowable injection pressure (MAIP). Pressure gauges are installed on the tubing and the casing of the Riverton East 36-3 salt water disposal well and the entire system is checked daily by the lease operator employees. Injected fluids are disposed into the Frontier and Nugget formations at 9,765 to 10,743 feet and 12,068 to 12,750 feet, respectively. Both injection zones are isolated from shallow and deeper aquifers by the Cody Shale upper confining zone and the Chugwater lower confining zone.

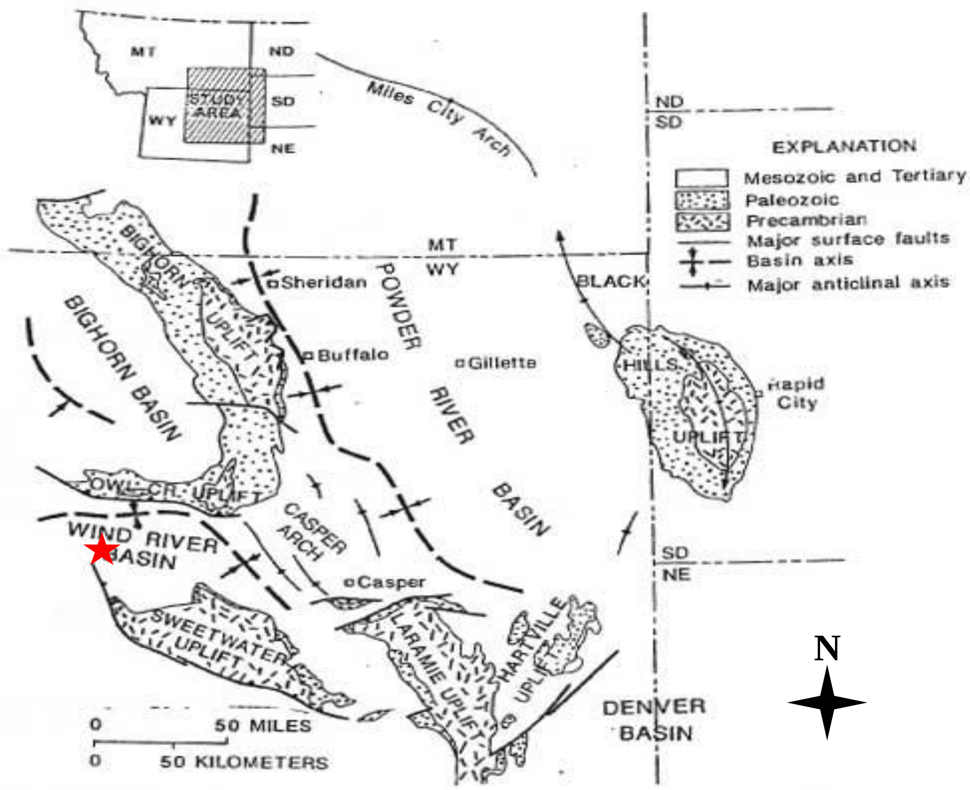
EPA notified Wesco Operating, Inc (Wesco) of the need to submit a UIC permit application for the Riverton East 36-3 disposal well on August 21, 2019 in order to continue injection activities. In response, Wesco submitted a complete application on September 30, 2019.

## PART II. Permit Considerations (40 CFR § 146.24)

### Hydrogeologic Setting

The Wind River Basin is located in the central portion of Wyoming and is greater than 13,000 feet deep at the location of the Riverton East 36-3 well. It is bounded to the north by the Absaroka and Owl Creek Mountains, to the east by the Casper Arch, to the south by the Granite Mountains, and to the west by the Wind River Mountains. The Riverton East 36-3 well is located within the Riverton Dome East Field in the central portion and south of the structural trough of the Wind River Basin. The approximate location of the Riverton East Dome Field within the Wind River Basin and relative to other major structural basins of Wyoming is depicted in Figure 2.1. The Riverton Dome East Field is located approximately 4.5 miles north-northwest of the furthest mapped trace of the Emigrant Trail Thrust Fault System, which was responsible for the stratigraphic and structural discontinuities (e.g. anticlinal structures) associated with the Alkali Butte, Sand Draw and Beaver Creek Fields located to the south and southwest of the Riverton Dome East Field (Reynolds, 1978).

**FIGURE 2.1: WIND RIVER BASIN (Dolton et al, 1990)**




The Riverton East 36-3 well has injected into the Nugget Sandstone since 1971, and by 1985, also included injection into the Frontier Formation. The Jurassic-aged Nugget Sandstone at the Riverton East 36-3 well is 682 feet thick according to reported formation tops, and in general, is comprised of cross-bedded and wave-rippled sandstone with minor beds of siltstone (Kirschbaum et al, 2007).

The Cretaceous-aged Frontier Formation at the Riverton East 36-3 well is 978 feet thick according to reported formation tops. The Frontier Formation consists of a sequence of alternating sandstones and shales of marine and nonmarine origin, and the sandstones are fine to medium grained, thin bedded to massive, cross-bedded in part and lenticular (Keefer, 1972).

The base of the Frontier Formation is located 1,325 feet above the top of the Nugget Sandstone. Several stratigraphic units identified as aquifers by the Wyoming Water Development Commission in the Wind/Big River Basin, Level I (2008-2011) Groundwater Study are present in between the Frontier Formation and the Nugget Sandstone. Specifically, these stratigraphic units are not part of the historical injection zone and include the Muddy Sandstone, Dakota Sandstone, Lakota Sandstone (sometimes referred to as the Cloverly Formation), and Sundance Formation. Each of these stratigraphic units is bound above and below by predominantly shale lithologies of the intervening formations and stratigraphic units described in Table 2.1. The formation depths and descriptions were obtained from the permit application and supplemental information in the EPA files for the Riverton East 36-3 well.

**TABLE 2.1**
**Geologic Setting**

| Formation Name or Stratigraphic Unit | Top (ft)* | Base (ft)* | TDS (mg/L)[1] | Lithology |
|---|---|---|---|---|
| Wind River | 0 | 3,390 | 555 – 5,832 | Sandstone, siltstone, shale |
| Fort Union | 3,390 | 4,392 | 2,897 – 8,817 | Sandstone, siltstone, coal |
| Lance | 4,392 | 4,787 | 3,520 | Sandstone, siltstone, shale |
| Mesaverde | 4,787 | 6,025 | 2,557 – 8,274 | Sandstone, shale, coal |
| Cody | 6,025 | 9,765 | 7,052 - 10,100 | Shale |
| Frontier | 9,765 | 10,743 | 13,124 – 44,461 | Sandstone and shale |
| Mowry | 10,743 | 11,157 | -- | Shale |
| Muddy | 11,157 | 11,190 | 2,726 – 43,789 | Sandstone |
| Thermopolis | 11,190 | 11,388 | -- | Shale |
| Dakota | 11,388 | 11,418 | 2,806 – 19,590 | Sandstone |
| Fuson | 11,418 | 11,474 | -- | Shale |
| Lakota/Cloverly | 11,474 | 11,510 | 6,803 – 15,679 | Sandstone |
| Morrison | 11,510 | 11,690 | -- | Shale |
| Sundance | 11,690 | 12,047 | -- | Sandstone |
| Gypsum Springs | 12,047 | 12,068 | -- | Gypsum, shale |
| Nugget | 12,068 | 12,750 | 11,877 – 216,565 | Sandstone |
| Chugwater | 12,750 | 13,240 | -- | Mudstone, siltstone |
| Dinwoody | 13,240 | 13,385 | -- | Dolomite |
| Phosphoria | 13,385 | 13,696 | 10,310 – 123,249 | Dolomite |

| | | | | |
|---|---|---|---|---|
| Tensleep | 13,696 | 13,709 | 5,131 – 16,105 | Sandstone and dolomite |

* depths are approximate values at the wellbore

[1] Water quality data in application supplemented from regional data available in the USGS Produced Water Database v2.3 and USGS National Water Information System.

References:


Dolton, G. L., Fox, J. E., and Clayton, J. L., 1990. Petroleum Geology of the Powder River Basin, Wyoming and Montana. U.S. Geologic Survey Open-File Report 88-450 P.

Keefer, W. R., 1972. Frontier, Cody, and Mesaverde Formations in the Wind River and Southern Bighorn Basins, Wyoming. Geology of the Wind River Basin, Central Wyoming, U.S. Geological Survey Professional Paper 495-E.

Kirschbaum, M. A., Lillis, P. G., Roberts, L. N. R., 2007. Geologic Assessment of Undiscovered Oil and Gas Resources in the Phosphoria Total Petroleum System of the Wind River Basin Province, Wyoming. Petroleum Systems and Geologic Assessment of Oil and Gas in the Wind River Basin Province, Wyoming, U.S. Geologic Survey Digital Data Series DDS-69-J.

Reynolds, M. W., 1978. Late Mesozoic and Cenozoic Structural Development and Its Effect on Petroleum Accumulation, Southwest Arm of the Wind River Basin, Wyoming. Wyoming Geologic Associated, Resources of the Wind River Basin; 30th Annual Field Conference Guidebook, pages 77-78.


**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 must 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 (AOR).

**TABLE 2.2**
**INJECTION ZONE**

| Formation Name or Stratigraphic Unit | Top (ft)* | Base (ft)* | Porosity | Exemption Status |
|---|---|---|---|---|
| Frontier | 9,765 | 10,743 | 11% | Not Applicable |
| Nugget | 12,068 | 12,750 | 8% | Not Applicable |

* depths are approximate values at the wellbore

Available water quality data shows the TDS content for both formations is greater than 10,000 milligrams per Liter (mg/L), and neither formation serves as a drinking water source. As a result, aquifer exemptions for the Frontier Formation and Nugget Sandstone are not required.

**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.

**TABLE 2.3**
**CONFINING ZONES**

| Formation Name or Stratigraphic Unit | Top (ft) | Base (ft) | Lithology |
|---|---|---|---|
| Cody (Upper confining zone for Frontier Formation) | 6,025 | 9,765 | Shale |
| Mowry (Lower confining zone for Frontier Formation) | 10,743 | 11,157 | Shale |
| Gypsum Springs (Upper confining zone for Nugget Sandstone) | 12,047 | 12,068 | Gypsum and shale |
| Chugwater (Lower confining zone for Nugget Sandstone) | 12,750 | 13,240 | Mudstone and siltstone with sandstone and limestone members |

* 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 groundwater 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.

The Permittee has identified the Wind River Formation as the primary USDW in the area. The formation is a major aquifer yielding water to springs and wells throughout the Wind River Basin. The Wind River Formation is described as alternating siltstone, shale, claystone, argillaceous to fine grained to arkosic sandstone. It has a thickness of approximately 3,390 feet in Section 36-Township 1 North – Range 5 East.

The nearest water well log data available is Township 1 North – Range 4 East- Section 6 (Wyoming State Engineers Office Permit No. 69278). This water well has been completed to a depth of 278 feet below ground surface in a red shale, which corresponds to a completion in the Wind River Formation. The well was perforated in an alluvial sand bearing lens from 260 feet to 272 feet below ground surface.

Water quality data presented in the permit application was supplemented with regional water quality data available in the United States Geologic Survey (USGS) Produced Water Database v2.3 and USGS National Water Information System. Water quality data was identified for the Wind River Formation, Fort Union Formation, Lance Formation, sandstones of the Cody Shale, Mesaverde Formation and Lakota Sandstone/Cloverly Formations in the Riverton East and nearby Indian Butte, Alkali Butte North, and Riverton Dome Fields. In instances where no or limited water quality data was available, regional water quality data was identified within the broader Wind River Basin from samples collected at comparable depths, specifically for the Muddy Sandstone and Dakota Sandstone.

Based on a review of available local and regional water quality data presented in the application or otherwise supplemented, Table 2.5 presents a summary of formations that are known or potential USDWs.

**TABLE 2.5**
**UNDERGROUND SOURCES OF DRINKING WATER (USDWs)**

| Formation Name or Stratigraphic Unit | Top (ft)* | Base (ft)* | TDS (mg/L)[1] | Lithology |
|---|---|---|---|---|
| Wind River | 0 | 3,390 | 555 – 5,832 | Sandstone, siltstone, shale |
| Fort Union | 3,390 | 4,392 | 2,897 – 8,817 | Sandstone, siltstone, coal |
| Lance | 4,392 | 4,787 | 3,520 | Sandstone, siltstone, shale |
| Mesaverde | 4,787 | 6,025 | 2,557 – 8,274 | Sandstone, shale, coal |
| Cody | 6,025 | 9,765 | 7,052 - 10,100 | Shale |
| Muddy | 11,157 | 11,190 | 2,726 – 43,789[2] | Sandstone |
| Dakota | 11,388 | 11,418 | 2,806 – 19,590[2] | Sandstone |
| Lakota/Cloverly | 11,474 | 11,510 | 4,319 – 45,960[2] | Sandstone |
| Sundance | 11,690 | 12,047 | --[3] | Sandstone |
| Tensleep | 13,696 | 13,709 | 5,131 – 16,105 | Sandstone and dolomite |

* depths are approximate values at the wellbore

1 Water quality data in application supplemented from regional data available in the USGS Produced Water Database v2.3 and USGS National Water Information System.

2 Considered USDW until demonstrated otherwise, as information presented in the application and regional water quality sample results supplemented from USGS Produced Water Database v2.3 indicate potential USDW status.

3 Considered USDW until demonstrated otherwise, as information presented in the application indicated potential USDW status.

## PART III. Well Construction (40 CFR § 146.22)

The approved well construction plan, incorporated into the Permit in APPENDIX A and actions required in APPENDIX F, will be binding on the Permittee. Modification of the well 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

Existing well construction details for the injection well(s) are shown in TABLE 3.1. As outlined in APPENDIX F, specific actions, including well construction modification, are required as part of the Permit prior to recommencing injection.

**TABLE 3.1**
**EXISTING WELL CONSTRUCTION**

| Casing Type | Hole Size (in) | Casing Size (in) | Cased Interval (ft) | Cement Records |
|---|---|---|---|---|
| Surface | 17.5 | 13 3/8 | 0 – 1,205 | 1,150 sacks |
| Longstring | 12.25 | 9 5/8 | 0 – 10,454 | 340 sacks |
| Liner | 8.625 | 7 | 10,375 -13,552 | 335 sacks |

**Injection 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 within 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

**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; and 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

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

## PART IV. Area of Review and Additional Conditions (40 CFR § 144.52)

**Area of Review (AOR)**
Permit applicants are required to identify the location of all known wells within the AOR which penetrate the injection zone(s). 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.

The AOR for this application is a ¼ mile radius centered on the surface location of the Riverton East 36-3 injection well. There are no other wells completed in the ¼ mile radius area of review of the proposed Riverton East 36-3 injection well.

**Actions Required Prior To Recommencing Injection**
Based on a review of well completion records and cement bond logs for the Riverton East 36-3 well, modification to the existing well construction, logging, testing and analysis is required under this permit prior to continued operation of the well. As explained further below, EPA was unable to determine from available records whether the well has mechanical integrity and is protective of USDWs. As a result,

Part II, Section A(4) of the Permit requires that the Riverton East 36-3 well be shut-in within ten (10) days of the effective date of the Permit. Authorization to resume injection will not occur until logging and testing outlined in APPENDIX B, actions outlined in APPENDIX F, and if applicable, modifications to the permit, have been approved by the Director. The actions required prior to recommencing injection are incorporated into the Permit as APPENDIX F and becomes binding on the Permittee. The Permit requires that the actions be completed prior to recommencing injection at the Riverton East 36-3 well or within one (1) year of permit issuance, whichever is sooner.

The Riverton East 36-3 well was drilled in 1966 and completed to a total depth of 13,552 ft-KB. Well completion records indicate that the 9.625-inch production casing was cemented at 10,454 ft-KB with 340 sacks of cement. A 7-inch liner was hung from the 9.625-inch casing and cemented at 13,552 ft-KB with 330 sacks of cement. The well was originally completed to the Phosphoria Formation but was plugged back with a cement retainer at 13,340 ft-KB and bridge plug at 12,259 ft-KB. The well has existing open perforations between 10,000 and 10,354 ft-KB in the Frontier Formation and between 12,100 and 12,178 ft-KB in the Nugget Sandstone.

A review of the March 14, 1966 cement bond log (CBL) for the 9.625-inch casing of Riverton East 36-3 well indicated an apparent interval of poor cement bond from the top perforation in the Frontier Formation at 10,000 ft-KB to the reported top of cement at 9,651 ft-KB. The top of cement in the March 14, 1966 CBL is consistent with the top of cement reported in the permit application. No cement was reported above 9,651 ft-KB to the base of the Mesaverde Formation at 6,025 ft-KB. The Mesaverde Formation is the next identified aquifer above the injection zone in the Frontier Formation. Regionally available water quality data, summarized in Part II above, supports that the Mesaverde Formation is a USDW with TDS concentrations less than 10,000 mg/L. Consequently, the existing CBL is not adequate to demonstrate mechanical integrity as defined in 40 CFR § 146.8(a)(2) and conformance with the Class II construction requirements in 40 CFR § 147.22(b)(1). Further, Part II, Section B.2 of the permit requires that injected fluids remain in the authorized injection zone, and the March 14, 1966 CBL is not adequate to demonstrate that this permit requirement will be met.

Similarly, a review of the August 13, 1971 CBL for the 7-inch liner indicated an apparent interval of predominantly poor cement bond from the top perforation in the Nugget Sandstone at 12,100 ft-KB to 10,354 ft-KB. There are four (4) aquifers in between the Frontier Formation and the Nugget Sandstone. These include the Muddy Sandstone at 11,157 ft-KB, the Dakota Sandstone at 11,388 ft-KB, the Lakota Sandstone at 11,474 ft-KB and Sundance Formation at 11,690 ft-KB. Regionally available water quality data, summarized in Part II above, support that the Muddy, Dakota and Lakota Sandstones may be USDWs with TDS concentrations less than 10,000 mg/L. No regional water quality data was identified for the Sundance Formation. The potential USDW status of these stratigraphic units was acknowledged in supplemental information submitted on December 18, 2019 to support the application. As a result, the Muddy Sandstone, Dakota Sandstone, Lakota Sandstone and Sundance Formations are conservatively considered USDWs until demonstrated otherwise. Consequently, the existing CBL is not adequate to demonstrate mechanical integrity as defined in 40 CFR § 146.8(a)(2) and conformance with the Class II construction requirements in 40 CFR § 147.22(b)(1). Further, Part II, Section B.2 of the permit requires that injected fluids remain in the authorized injection zone, and the August 13, 1971 CBL is not adequate to demonstrate that this permit requirement will be met.

As a result, actions required prior to recommencing injection were incorporated into APPENDIX F of the permit. These requirements include modification to the existing well construction, logging, testing and analysis necessary to demonstrate conformance with 40 CFR § 147.22(b)(1), 40 CFR § 146.8(a)(2) and/or Part II, Section B.2 of the permit. Injection into the Riverton East 36-3 well will not resume until written authorization to resume injection has been received from the Director. Authorization to resume injection will not occur until the required actions, and if applicable, modifications to the permit, have been approved by the Director.

## PART V. Well Operation Requirements (40 CFR § 146.23)

**Mechanical Integrity (40 CFR § 146.8)**
An injection well has mechanical integrity (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 prior to recommencing injection and periodically thereafter, 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 the 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.

A successful internal Part I Mechanical Integrity Test (MIT) is required prior to receiving authorization to inject and repeated 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 mechanical integrity, 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.

Following completion of the requirements in APPENDIX F, external (Part II) MIT must be demonstrated by periodic evaluation of a temperature survey as required in APPENDIX B of the permit. Guidance on temperature logging for mechanical integrity can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

**Injection Fluid Limitation**
Injected fluids are limited to those identified in 40 CFR § 144.6(b) as fluids (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure.

This Permit does not allow for the injection of any hazardous waste as defined in 40 CFR § 261.3. Injection of any substance defined as a hazardous waste, whether hazardous by listing or characteristic, is a violation of this permit and requires notification under Part III, Section D.11. Additionally, non-hazardous fluids that do not fall within the above definition for a Class II fluid defined in 40 CFR § 144.6(b) are not approved for injection.

Prior to introduction of a new source (e.g. different production formation, well field, waste stream etc.) into the well, a fluid analysis is required, as listed in APPENDIX D under "PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee must provide a description of the fluid, including the process that generated the fluid, a representative sample of the new fluid source and a notification to the Director, as required in APPENDIX B. Results of the fluid analysis will be used to determine if a new MAIP is required. See Part II, Section B.4 Injection Pressure Limitation. 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 MAIP.

**Injection Pressure Limitation**

40 CFR § 146.23(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 confining zone adjacent to the USDWs. In lieu of testing the fracture pressure of the confining zone, which may be impractical, the pressure in the injection formation provides a conservative surrogate.

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, 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

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.

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:

**MAIP** = **FP** + 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 also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for injection. 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 equation, 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 confining zones adjacent to the USDWs. 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 or historical permit file. 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 | Top Open Perforation Depth (ft) | Specific Gravity | Fracture Gradient (psi/ft) | Friction Loss (psi) | Estimated Formation FP (psi) |
|---|---|---|---|---|---|
| Frontier | 10,000 | 1.014+0.05 | 0.733 | N/A | 2,722 |
| Nugget | 12,100 | 1.014+0.05 | 0.733 | N/A | 3,291 |

The depths listed in the table are the locations of the top open perforations for each injection zone.

Fracture gradients for the Frontier Formation (0.65 psi/ft) and Nugget Formation (0.72 psi/ft) were identified by a previous operator and submitted to the EPA in a permit application (UIC Permits EPA No. WY2000-03091), dated December 17, 1992.

In the 2020 calendar year, the maximum (averaged daily per month) tubing pressure was 2,424 psi and the average pressure was 2,369 psi. The current maximum injection pressure for the Riverton East 36-3 well is 3000 psi. A MAIP of 3,000 psig was approved by EPA in a July 30, 1997 letter. The pressure limit was calculated using the formation fracture gradient of 0.733 psi/ft for both the Frontier and Nugget injection zone. However, no step rate test data for the Riverton East 36-3 well is included in the permit application or file. The MAIP for this permit action is lowered to 2,722 psi in accordance with the most conservative value calculated and included in Table 5.1. As a result, a step rate test must be performed to identify/verify an appropriate injection pressure for both approved injection zones of the Riverton East 36-3 well. The MAIP will be updated based upon the step rate test data.

## 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 parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA annually as part of the Annual 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, cumulative fluid volume, bradenhead and TCA pressures must be observed on a weekly basis. A recording, at least monthly, must be made of that month's injected volume and cumulative fluid volume to date, the maximum and average value for injection tubing pressure and rate, maximum and minimum annulus and bradenhead pressures. This information is required to be reported annually as part of the Annual 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.

The Permittee has submitted plugging and abandonment cost estimates and updated the amount of financial assurance. A Letter of Credit in the amount of $127,500 has been submitted to EPA to address financial assurance requirements for this well.

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

EPA will ensure that issuance of this Permit will be 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 II injection well permit for authorization of injection into the Riverton East 36-3 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800. Existing operations occurring at the Riverton East 36-3 well are not expected to impact historical properties identified for Fremont County, Wyoming. There are two properties in Riverton, Wyoming near the proposed injection well.

| HISTORICAL PROPERTY | LOCATION |
|---|---|
| Delfelder Schoolhouse | 43.083611, -108.360278 |
| Riverton Railroad Depot | 43.024444, -108.39 |

**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 issue a Class II permit for authorization of injection into the Riverton East 36-3 well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402).

The continued operation of the Riverton East 36-3 will not result in any new well construction or ground disturbance. Nor will regular operation and inspection activities affect endangered species in the area. Therefore, the operations at the Riverton East 36-3 well will not affect endangered species and habitat in the area. Species of interest in the area are:

Migratory Birds
- Bald Eagle
- Clarks Grebe

Endangered Species – Flowering Plants
- Desert Yellowhead
- Ute Ladies - tresses

**Executive Order 12898**
EPA is complying with Executive Orders, including, to the extent applicable, E.O. 13175 Consultation and Coordination with Indian Tribal Governments and E.O. 12898 entitled “Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations.”