STATEMENT OF BASIS

Big Bend 3-6 SWD
Mountrail County, North Dakota

EPA PERMIT NO. ND22361-11336

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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 ND22361-11336 (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 and 146, and address potential impacts to underground sources of drinking water. 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.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection well or wells so that the injection does not endanger USDWs. The Permit is issued for the operating life of the injection well or project 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

Slawson Exploration Company, Inc. (Slawson)
1675 Broadway, Suite 1600
Denver, Colorado 80202

hereinafter referred to as the "Permittee," submitted an application for an Underground Injection Control (UIC) Program permit for the following Class II commercial injection well:

Big Bend 3-6 SWD
250 feet FNL, 200 feet FWL
Section 6, Township 151 N, Range 92 W
Mountrail County, North Dakota

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.

PART II. Permit Considerations (40 CFR §146.24)

Hydrogeologic Setting

The Fort Berthold Indian Reservation is about 15 miles east of the center of the Williston Basin, which has produced over 700 million barrels of oil, one of the largest cratonic basins in North America. On the reservation, much of the oil in this area was sourced by the organically rich Bakken and Three Forks Formations.

In the eastern part of the Reservation, bedrock dips gently westward into the center of the Basin, generally at less than 10 feet per mile, although in some small structures dips may exceed 150 feet per mile. The north-trending Nesson anticline parallels the western boundary of the Reservation, passing between the center of the Williston Basin and the western boundary of the Reservation. The Antelope anticline extends southeastward from the Nesson anticline into the northwest corner of the Reservation.

The general geologic stratigraphy of the area in the vicinity of the proposed Big Bend 3-6 SWD injection well consists of the following units and their characteristics:

TABLE 2.1
GEOLOGIC SETTING

Formation Name or Stratigraphic Zone	Top (ft) *	Base (ft) *	TDS (mg/l)	Lithology
Coleharbor	0	23		Silty Clay, Sand and Gravel
Bullion Creek / Tongue River	23	558	2,110	Siltstone, clay and shale with lignite and limestone
Cannonball	558	1,043	1,530	Sand and Mudstone
Hell Creek	1,043	1,413	1,530	Sand and lignitic shale
Fox Hills	1,413	1,656		Sandstone, siltstone and Shale
Pierre	1,656	3,701		Shale
Niobrara	3,701	3,958		Calcareous Shale
Carlile	3,958	4,184		Gypsiferous Shale
Greenhorn	4,184	4,367		Shale with thin bedded limestone
Belle Fourche	4,367	4,586		Bentonitic Shale
Mowry	4,586	4,940		Shale
Inyan Kara	4,940	5,379	Unknown	Sandstone with interbedded shale
Swift	5,379	5,822		Shale
Rierdon	5,822			Shale and limestone

* depths are approximate values at the wellbore

Source: United States Geological Survey, 1998, Water Resources of the Fort Berthold Indian Reservation, West Central North Dakota, Water Resources Investigations Report 98-4098.

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 proposed injection formation for UIC Permit ND22361-11336 is the Inyan Kara Formation in the Dakota Group. The depth interval of the proposed injection formation in the proposed Big Bend 3-6 injection well is estimated to be between about 4,940 to 5,379 feet deep. The Inyan Kara Formation injection zone as sampled in nearby injection wells contained groundwater TDS concentrations of less than 10,000 mg/l. Aquifer exemptions were required for these wells to allow for the injection of Class II fluids from nearby production wells. Because of the proximity of existing aquifer exemptions in the Inyan Kara Formation it is possible that an aquifer exemption may be required for this proposed well. Sampling of the Inyan Kara Formation will be required to determine if an aquifer exemption will also be required for the Big Bend 3-6 proposed injection well.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Zone	Top (ft)*	Base (ft)*	TDS(mg/l)	Lithology
Inyan Kara Formation	4,940	5,379	Unknown	Sandstone with Interbedded Shale

* depths are approximate values at the wellbore

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 immediate upper Confining Zone for UIC Permit ND22361-11336 is the Mowry Formation from an approximate depth interval of 4,586 feet to 4,940 feet. The upper confining zone may include additional geologic units above the Mowry Formation where extensive thicknesses (approximately 3,000 feet) of relatively impermeable shale units occur. The lower Confining Zone is the Swift Formation from an approximate depth interval of 5,379 feet to 5,822 feet.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Zone	Top (ft)*	Base (ft)*	Lithology
Mowry	4,586	4,940	Shale
Swift	5,379	5,822	Shale

* 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 total dissolved solids (TDS), are considered to be USDWs.

Pursuant to the UIC regulations at 40 CFR § 144.12, underground injection cannot cause movement of a contaminant into a USDW. If data indicates that the receiving aquifer is a USDW, an aquifer exemption would be necessary before injection could be authorized.

In the area of the proposed Big Bend 3-6 SWD well, there are several aquifers that qualify as USDWs. The lowermost USDW that is being used for human consumption is the Fox Hills Aquifer. Between the Fox Hills and the proposed injection zone in the Inyan Kara, there is approximately 3,200 feet of Pierre Shale and other confining units below the Pierre. The TDS of the Inyan Kara varies throughout the state. Nearby injection wells show TDS concentrations of less than 10,000 mg/l indicating it is a USDW in the area. At this time, it is unknown if the Inyan Kara is a USDW at this specific location. Samples of the formation water will be collected during well construction to determine the TDS. If the TDS is under 10,000 mg/l, the Permittee will need to apply for and obtain approval for an aquifer exemption (AE) prior to receiving authorization to inject. The EPA has determined that USDWs will be protected considering the thickness of the confining units and well construction and monitoring requirements.

Shallow USDWs in the vicinity of this proposed injection well are generally less than 1,656 feet in depth and consist of the following units:

- Coleharbor Formation of Pleistocene age consist of about 23 feet of unconsolidated sediments, genetically related to glacial processes and a northerly clastic sediment source. Three general categories are recognized and consist of pebbly sandy silty clay (87%); sand and gravel (8%); and silt and clay (5%). The "pebbly, sandy, silty clay" unit is inferred to be glacial till, has low permeability, and consequently of low permeability. The "sand and gravel unit" thought to be derived from glacial rivers, is a well-sorted, highly permeable aquifer, and in the largest source of potable groundwater in Mountrail County. The "silt and clay unit" is another low permeability unit and was deposited in larger glacial lakes.
    - An observation well, constructed and monitored by the US Geological Survey for 16 months in 1967-1968, was located approximately 600 feet to the NNE of the proposed Big Bend 3-6 proposed location. This well with a total depth of 80 feet has since been abandoned. Sandstone and shale bedrock was encountered at about 58.5 feet. The overlying unconsolidated units consisted of a series of interbedded clays (20 feet thick) overlying gravels and sands (38.5 feet thick). The water table in this well ranged from about 24.3 to 25.46 feet deep over the 16-month measurement period. This data was recovered from the North Dakota State Water Commission Map Services Website.

- Bullion Creek Formation of Paleocene age consists of about 535 feet of interbedded silt and clay, varying amounts of sand, lignite, limestone, and sandstone. Equivalent to strata referred to as the Tongue River Formation.

- Cannonball Formation of Paleocene age consists of about 485 feet of sand and mudstone, brownish-yellow and light gray with lenticular and concretionary sandstone.

- Hell Creek Formation of Cretaceous age consist of about 370 feet of sand, somber shades of light-gray to brownish-gray, and cross bedded sandstone with lignitic shale and dark-purple, manganese oxide stained concretions.

- Fox Hills Formation of Cretaceous age consist of about 243 feet of silt and shale, sandy shale, sandstone and siltstone, shades of buff to yellowish-brown; interbedded with lignitic shale laminae; some beds are fossiliferous; intermittent sandstone at the top is grayish-brown to white, fine, siliceous; silty and shale gradational downward with the shale of the Pierre Formation.

The Inyan Kara Formation of the Dakota Group is considered a USDW (TDS < 10,000 mg/l) in parts of North Dakota. In general, much of the Inyan Kara in the western part of the Williston Basin exceeds 10,000 mg/l TDS and is therefore not considered a USDW. The upper part consists mainly of marine sandstone, light-gray, fine to coarse, quartzose; and shale, gray, silty, and lumpy. The lower part is mainly nonmarine sandstone, medium to coarse, angular to subrounded, quartzose with occasional lenses of gray, bentonitic shale commonly containing manganese-siderite spherulites (pellets).

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name of Stratigraphic Zone	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Coleharbor	0	23		Sands, silts, and gravel
Bullion Creek / Tongue River	23	558	1,110	Siltstone, clay and shale, lignite and limestone
Cannonball	558	1,043	1,530	Sand and mudstone
Hell Creek	1,043	1,413	1,530	Sandstone and lignitic shale
Fox Hills	1,413	1,656		Sandstone, siltstone and shale
Inyan Kara	4,940	5,579	Variable	Sandstone with interbedded Shale

* depths are approximate values at the wellbore

PART III. Well Construction (40 CFR §146.22)

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)
J-55, 36 lbs/ft	13.5	9.625	0-1,776	0-1,776
N80, 23 lbs/ft	8.75	7	0-5,530	0-5,530
J-55, EUE internal plastic coated	NA	3.5	0-4,865~	NA

No well stimulation program is proposed during well completion. The Permittee shall follow the requirements in Part II, Section B.8. Alteration, Workover, and Well Stimulation should the Permittee choose to stimulate the well.

The surface casing into the Pierre Shale and longstring casing cemented to surface is expected to be protective of the shallow USDWs shown in Table 1 to a depth of approximately 1,776 feet.

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.

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 include 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; and 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 non-resettable flow meter that measures the

cumulative volume of 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)

Area of Review (AOR)
Permit applicants 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 (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.

In this case, the radius of the AOR has been calculated to be 3,325 feet from the proposed well location. The AOR calculation is based upon using an injection period of 40 years assuming the injection of 15,000 barrels/day, a porosity of 20% and an injection zone thickness of 177 feet (estimated thickness of porous sandstones within the Inyan Kara Formation).

There are eight known oil wells within the 3,325 foot radius of the AOR shown of Figure 1.

- The Sniper (Federal) 2-6-7H (Bakken), API 33-061-01867-00-00
- Sniper (Federal) 5-6-7TFH (Three Forks), API 33-061-02180-00-00,
- Whirlwind 2-31H (Bakken), API 33-061-01866-00-00
- Rainmaker (Federal) 10-36-25TF2H, API 33-061-03258-00-00
- Sniper (Federal) 1 SLH API 33-061-03084-00-00
- Zephyr 1-36H API 33-061-01137-00-00
- Stallion 1-1-12H API 33-061-01063-00-00
- Stallion 6-1-12TFH API 33-061-03085-00-00

The following characteristics of the nearby production wells were considered by the EPA in determining that no corrective actions are necessary of the adjacent production wells within a 3,325 foot radius of the proposed well.

- Surface casing has been installed in each of the production wells and cemented into the Pierre Shale that immediately underlies the shallow USDWs in the area, sufficiently inhibiting the migration of fluids from the injection zone into shallow USDWs.
- Geologic formations between the base of the shallow USDWs and the top of the injection formation (Inyan Kara Formation) are approximately 3,000 feet thick and consist of relatively impermeable shales.
- The production casings of the nearby production wells are cemented into the adjacent formations and appear adequate to prevent the migration of fluids along the outside of the casing.
- There are no known fractures or faults in the formations overlying the injection zone.

Figure 1 shows the location of the AOR wells. It also indicates there are no water wells or shallow glacial channels within the AOR of the proposed well location.

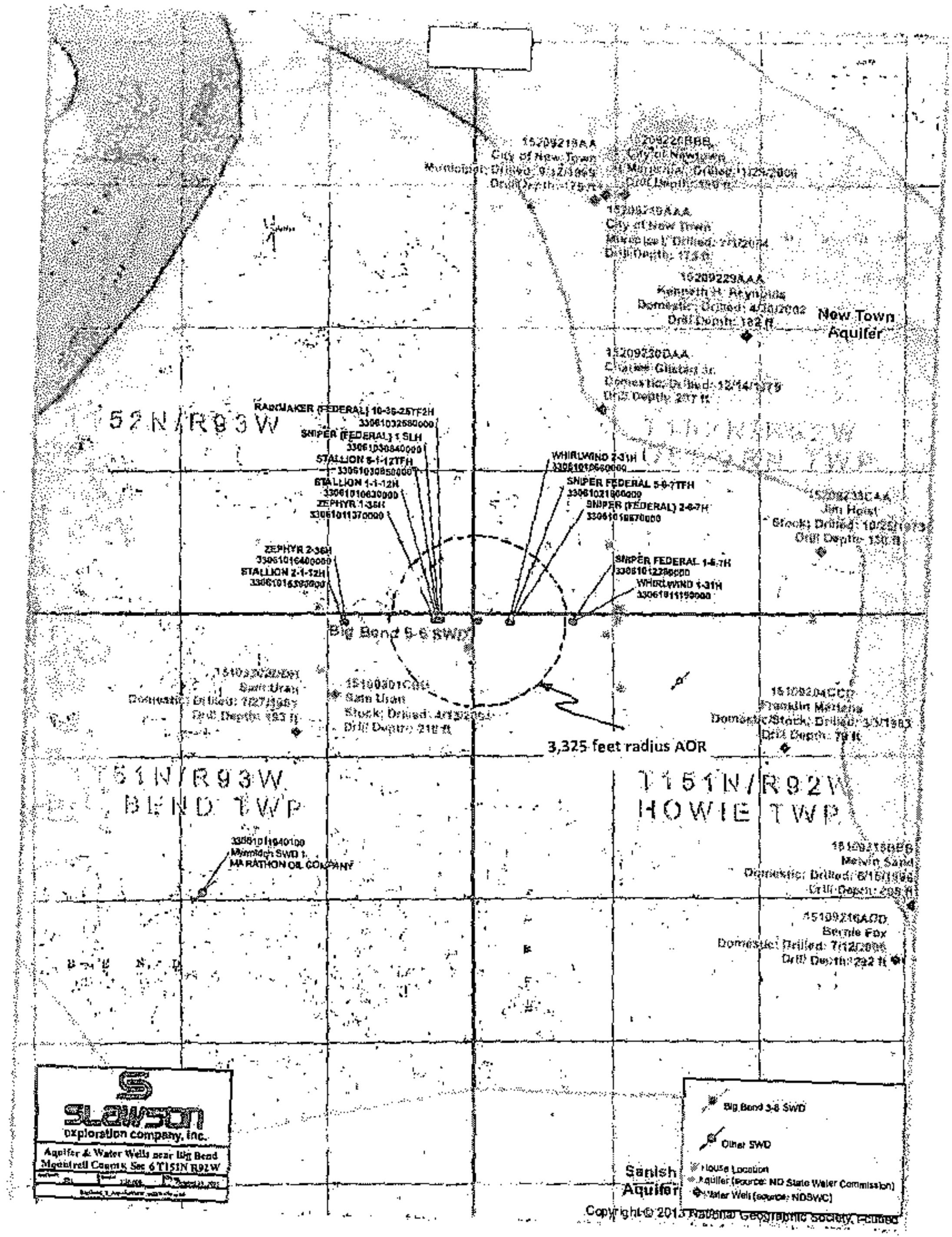

Figure 1. Oil, Gas, Injection and Water Wells located in the vicinity of the proposed Big Bend 3-6 SWD well

Corrective Action Plan (CAP)

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant 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 area of review.

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 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 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.

External (Part II) MIT may be demonstrated by evaluation of the cement bond log to show that adequate cement exists to prevent significant movement of fluid out of the approved injection zone through the casing annular cement (i.e., 80% bond index cement bond across the confining zone.) Guidance on the logging and interpretation of the cement bond log (CBL) can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Should the CBL analysis show inadequate external Part II MI, additional periodic tests will be required at a frequency no less than every five years after the last successful test. These requirements are found in Appendix B Logging and Testing Requirements of the Permit.

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. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection.

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, 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.

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.

The calculated Maximum Allowable Injection Pressure (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:

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

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

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 as described in the final well construction diagram.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director if the Permittee can demonstrate that a surface pressure gauge alone will provide accurate results 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 measure friction loss is to measure it directly. When conducting a step rate test, install both surface and bottom-hole gauges at depth **D**. This will allow a direct measurement of the pressure changes downhole and the difference between the two pressures will be the result of friction.

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. The 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 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 has changed, the formation fracture pressure will be recalculated. As required in Appendix B of the Permit, the Permittee will submit fluid analysis that reports SG annually and more frequently when a new source is introduced. The Director will only recalculate the MAIP when the new SG value is greater than the SG used to calculate the current MAIP. The Permittee is permitted to operate at the current MAIP when the fluid analysis shows that the SG of the injection fluid is at or below the SG used to calculate the current MAIP. The Director will provide written notification of the new permitted MAIP that corresponds to the newly calculated FP adjusted for friction loss, as applicable. 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. The permitted MAIP will be recalculated with the information submitted to obtain the authorization to commence injection.

TABLE 5.1
Estimated Injection Zone Fracture Pressure

Formation Name	Depth used to calculate FP (ft)	Specific Gravity	Fracture Gradient (psi/ft)	Estimated Formation FP (psi)
Inyan Kara	4,940	1.045-1.2	SRT is required to determine FG	TBD

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 as required in Appendix B Injectate Water Analysis of the permit. 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.

Disposal well(s) that accept fluids for a fee to dispose of fluids from third party producers is defined as a commercial disposal well. To ensure that only permitted fluids are injected into the well, the characteristics of the disposal fluids are more frequently analyzed and a manifest tracking system should be put into place that documents the origin of fluids and responsible parties during transfer of the wastewater. In addition, to prevent unauthorized disposal into the well, the site is secured to control entry into the disposal facility and include monitoring of the site (Appendix G of the Permit).

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 7520-14) 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) an independently audited financial statement with a Chief Financial Officer's letter.

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 statement 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 will be in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act (NHPA) and the Endangered Species Act (ESA) 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. The EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the Big Bend 3-6 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800. We have also determined that this undertaking has the potential to cause effects on historic properties.

Juniper, LLC (Juniper) issued a Cultural Resource Inventory (CRI) Report in October 2018 for the proposed Big Bend 3-6 SWD Class II commercial disposal well project. The Report is included in the administrative record for EPA's proposed action. The Inventory was conducted in October 2018, to Class III Intensive Pedestrian Inventory State Historical Society of North Dakota standards (SHSND 2017). The Inventory took place in a 20-acre block, centered on the well location, in an agricultural field that has been heavily disturbed by farming activities. A reclaimed or replanted pipeline scar runs east to west along the southern edge of the inventory block. Rodent burrows, road cut banks, and any other areas of increased visibility were intensively investigated for evidence of buried cultural materials that may not have a surface expression.

Juniper also conducted a Class I Literature Review of the State Historical Society of North Dakota's site and manuscript files in the spring of 2018, for a one-mile radius around the proposed development. This Review found that there are no previously recorded cultural resources based on four previous cultural investigations* within a mile of the proposed development.

EPA has reviewed the CRI and determined that the Area of Potential Effects (APE) for its action is the "Big Bend 3-6 SWD" inventory block and proposed well disturbance area identified in Figures 2 and 3 of Juniper's Report. This APE encompasses the well pad to be constructed for drilling the well and the access road from the existing county road that will need to be built to transport equipment, etc. for well construction. Juniper found that no cultural resources were present during its inventory effort. Based on this information, the EPA is proposing to find that there are no historic properties within the APE for this project, and therefore that no historic properties will be affected as a result of EPA's issuing a UIC permit for the proposed Big Bend 3-6 SWD Class II commercial disposal well.

*These investigations were done in 1990, 2009, 2013, and 2015 and are noted in page 7 of Juniper's Report.

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. The EPA has determined that a decision to issue a Class II permit for authorization of injection into the proposed Big Bend 3-6 SWD well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, the EPA will comply with these regulations by determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. The EPA's determination will be documented as part of the administrative record supporting this decision.

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." The 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. The EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. The EPA has concluded that the specific conditions of UIC Permit ND22361-11336 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.