FORT PECK OFFICE OF ENVIRONMENTAL PROTECTION

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: July 2013

DRAFT

Permit No. FPT2308-0870

Class II Salt Water Disposal Well

EPU 114
Roosevelt County, MT

Issued To

Nautilus Poplar LLC

1775 Sherman Street, Suite 1950

Denver, CO 80203

Part I. AUTHORIZATION TO CONSTRUCT AND INJECT

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the Fort Peck Assiniboine and Sioux Tribes' Office of Environmental Protection (OEP) codified at Title XXII Chapter 2 of the Fort Peck Tribes' Comprehensive Code of Justice (CCOJ) and according to the terms of this Permit,

Nautilus Poplar LLC 1775 Sherman Street, Suite 1950 Denver, CO 80203

is authorized to construct and to operate the following Class II injection well or wells:

EPU 114 921' FEL 277' FSL, SESE S28, T29N, R51E Roosevelt County, MT

OEP regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). OEP UIC Permit conditions are based on authorities set forth at Title XXII CCOJ Ch. 2, and address potential impacts to USDWs.

Under Title XXII CCOJ Ch. 2 Subchapters 2, 3, and 4, 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 are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Tribal, Federal, State or local laws or regulations. (Title XXII CCOJ Ch. 2 SubCh. 3, Sec. 221(4)). An OEP UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under Title XXII CCOJ Ch. 2 SubCh. 4, Sec. 231(d), and may be reviewed at least once every five (5) years to determine if action is required under Title XXII CCOJ Ch. 2 SubCh. 3, Sec. 221(5).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under Title XXII CCOJ Ch. 2 SubCh. 4, Sec. 231(c) and (d).

Issue Date: ____________________ Effective Date ____________________

____

Deb Madison
Environmental Programs Manager
Office of Environmental Protection
Fort Peck Assiniboine & Sioux Tribes

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

(i) on the injection tubing; and

(ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under Title XXII CCOJ Ch. 2 Ch. 4, Sec. 402(D), unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (FPT-UIC-1-0109), and shall provide this and any other record of well workover, logging, or test data to OEP within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

(a) There is no significant leak in the casing, tubing, or packer (Part I); and

(b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and every five (5) years thereafter in accordance with Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(c). Well-specific conditions dictate the methods and the frequency for demonstrating MI. These conditions are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

OEP-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from OEP and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable OEP to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed OEP Form FPT-UIC-1-0109 or 2-0109; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to Title XXII CCOJ Ch. 2 SubCh. 3, Sec. 221(b)(8) and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. Injection Volume Limitation.

Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation.

Injected fluids are limited to those which are brought to the surface in connection with conventional oil or natural gas production and 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, pursuant to 40 CFR 144.6(b). The well also may be used to inject approved Class II wastes brought to the surface such as drilling fluids and spent well completion, treatment and stimulation fluids. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved. This well is NOT approved for commercial brine or other fluid disposal operation.

6. Tubing-Casing Annulus (TCA)

The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters, Frequency, Records and Reports.

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. Monitoring Methods.

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under Title XXII CCOJ Ch. 2 SubCh. 5, Sec. 241(d). The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. OEP Form FPT-UIC-1-1208 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if OEP Form FPT-UIC-1-1208 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with Title XXII CCOJ 5, Ch. 2, SubCh. 5, Sec. 241(d) and other applicable Tribal, Federal, State, and local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abandonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (OEP Form FPT-UIC_4-0109) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Title XXII CCOJ Ch. 2, SubCh. 6 or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with Title XXII CCOJ Ch. 2, SubCh. 2, Sec. 211(6) and SubCh. 4, Sec. 231(c), (d), and (f). Also, this Permit is subject to minor modification for causes as specified in Title XXII CCOJ Ch. 2, SubCh. 4, Sec. 231(e). The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(7), this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (OEP Form FPT-UIC-1-0109) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(a) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Title XXII CCOJ Ch. 2; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (OEP Form FPT-UIC-1-0109), and shall provide this and any other record of well workovers, logging , or test data to OEP within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with Title XXII CCOJ Ch. 2 SubCh. 2, Sec. 211(b)(2), information submitted to OEP pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, OEP may make the information available to the public without further notice. Claims of confidentiality for the following information will be denied:

> The name and address of the Permittee, and information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Title XXII CCOJ Ch. 2 and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(3). All violations of the Title XXII CCOJ Ch. 2 may subject the Permittee to penalties and/or criminal prosecution as specified in Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(7).

2. Duty to Reapply.

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the Title XXII CCOJ Ch. 2, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(1). This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (406) 768-2389 and requesting the OEP Environmental Programs Manager, or by contacting the Roosevelt County 911 Center at (406) 653-6240.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The EPU 114D well was drilled to a total depth (TD) of 9200'. The plug back total depth (PBTD) is 7433'.

Surface Casing: A 9.625 inch casing was set at 976' in a 12.25 inch hole and cemented to surface with 415 sx of Regular cement with additives.

Production Casing: A 7 inch casing was set at 7661' in an 8.75 inch hole and cemented to surface with 207 sx of 50/50 Pozmix with additives and 485 sx of premium cement with additives. The CBL identifies the TOC at approximately 4145'.

The straddle packer assembly will be used to allow fluids to enter the Mission Canyon and Nisku formations and allow future use in the Charles Formation. The upper packer will be set within 100 feet of the top open Charles perforation and the lower packer will be set within 100 feet of the top open Mission Canyon perforation.

Perforations occur in the Charles (5604 to 5609 feet and 5709 to 5719 feet), two in the Mission (6447 to 6450 feet and 6451 to 6456 feet), and five in the Nisku (7302 to 7308 feet, 7320 to 7325 feet, 7340 to 7346 feet, 7352 to 7355 feet, and 7366 to 7372 feet).

KB: 2,171'
GL: 2,160'

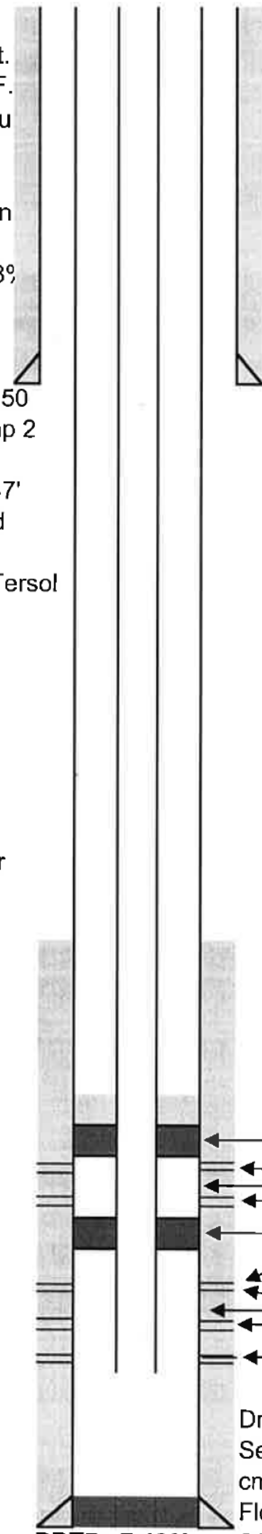
EPU No. 114
NAUTILUS POPLAR LLC
Surf Loc: 277' FSL & 921' FEL
SE SE, Sec 28, T29N, R51E
Roosevelt County, Montana
API # 25-085-21615

WORK HISTORY:

12/30/96 Fish in hole from 8282-9200'. 3 jts drill pipe, 27 drill collars & 8-3/4" bit.
1/15/97 Perf Nisku 7302-7308' @ 8 SPF. Acidized w/250 gal 15% HCl. Perf Nisku 7320-7325' @ 8 SPF. Acidized w/250 gal 15% HCl.
1/15/03 Set CIBP @ 7270'. Perf Mission Canyon 6447-6450' & 6451-6456' @ 4 SPF. Acidized 6447-6456' w/500 gal 28% HCl. Set CIBP @ 6420'. Perf B-1 5709-5719' @ 4 SPF. Acidized w/250 gal 28% HCl. Set CIBP @ 5680'. Perf A-3 5604-5609' @ 4 SPF. Acidized w/250 gal 28% HCl. Set CIBP @ 5570' & dump 2 sx cement on top.
9-16-07 Set Straddle Pkrs @ 5504&6347' isolating the Charles Formations. Added additional perfs to the Nisku. Acidize w/ 2,900 gals 15%HCL.Treat w/ 300 gals Tersol

Spud Date: 11/8/1996
Completion Date: 1/26/1997

Set 16", 26#, H-40 casing @ 87' & cemented to surface.
Surface Hole Size: 12-1/4" drilled to 980'
Set 9-5/8", 36#, K-55, LT&C casing @ 976' & cemented to surface with 415 sx regular cement containing 3% NaCl, 0.6% CFR-3, 0.25#/sk Flocele & 100 sx Premium cement containing 3% NaCl, 0.25#/sk Flocele.



174 jts coated 3 1/2, 4&8' sub above pkr
201 jts total coated PK 15 tubing

TOC behind 7" @ 4145' from CBL

27 jts 3 1/2 coated tbg.between pkrs

Upper Straddle Pkr @ 5504'
Charles 'A-3': 5604-5609', 4 SPF
Charles 'B-1': 5709-5719', 4 SPF
Lower Straddle Pkr @ 6347'
Mission Canyon: 6447-6450', 4 SPF
Mission Canyon: 6451-6456', 4 SPF
Nisku: 7302-7308', 8 SPF
Nisku: 7320-7330', 8 SPF
Nisku: 7340-46, 7352-55, 7366-72 8 SPF

Drilled 8-3/4" hole to 9200'
Set 7", 26#, L-80, LT&C casing @ 7661' & cmtd w/207 sx of 50/50 Pozmix with 0.25#/sk Flocele, 0.6% Halad 22-A, 2% HR-12, 25% SSA-1 & 485 sx Premium cmt with 0.4% CFR-3, 0.25#/sk Flocele, 0.6% Halad 22-A, 0.3% HR-12 & 35% SSA-1.

PBTD: 7,433'
TD: 9,200'
Csg Shoe @: 7,661'

Updated: 12/15/2005

EPU114_wellschematic.bmp

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.
Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

NO LOGGING REQUIREMENTS

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: EPU 114

TYPE OF TEST	DATE DUE
Standard Annulus Pressure	A Part I Mechanical Integrity Test (MIT) shall be conducted every 5 years. The next Part I MIT demonstration shall be conducted at least once every five (5) years after the last successful demonstration of Part I MIT.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
EPU 114	800

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: EPU 114

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Charles "A" and "B-1" Porosity	5,534.00 -	5,709.00	0.680
Mission	6,060.00 -	6,600.00	0.680
Nisku/Birdbear	7,295.00 -	7,377.00	0.680

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE WEEKLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

Notify Fort Peck Tribe Office of Environmental Protection and Montana Board of Oil and Gas Conservation Commission

Prior to plugging the well, run a Part I Mechanical Integrity Test and repair any casing leaks.

At a minimum, the following plugs are required:

Plug #1: Squeeze 50 sx below a cement retainer set at 7250'.

Plug #2: Squeeze 50 sx below a cement retainer set at 6375'.

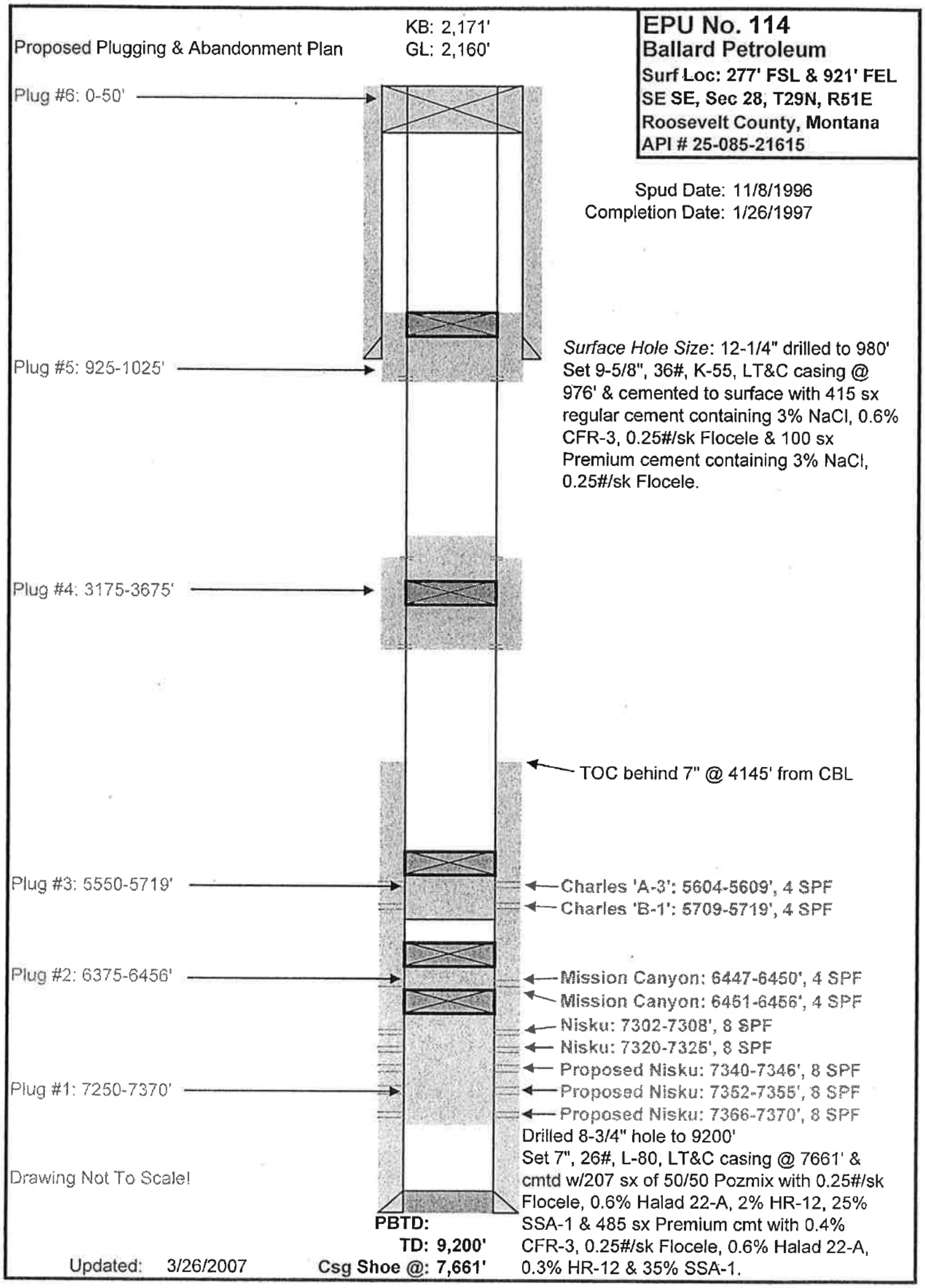
Plug #3: Squeeze 50 sx below a cement retainer set at 5550'.

Plug #4: Perforate and squeeze holes 50 feet above the Dakota and 50 feet below the Dakota. Block squeeze cement below a cement retainer set at the top of the Dakota and leave a minimum of 20 feet above the cement retainer.

Plug #5: Squeeze 50 sx below a cement retainer set at 925' through squeeze holes at 1025'.

Plug #6: Set a cement surface plug of at least 50 ft both inside and outside of the longstring casing to prevent surface water runoff from entering the plugged and abandoned well bore and to seal all possible pathways for fluid migration into the subsurface via the well.
Cut off below ground level and weld a dry hole marker to top of surface casing.

NOTE:
The key objective for injection well abandonment is to protect all USDWs. Critical intervals, such as USDWs, water-bearing zones, hydrocarbon-bearing zones, and confining zones may require separate plugs to adequately isolate and protect all USDWs. If there is more than 2,000 mg/L difference of TDS between individual exposed USDWs, they must be isolated from each other.
All balanced plugs must be verified by tagging the top of the plug after the cement has had adequate time to set. All cement retainers and cast-iron bridge plugs must have at a minimum 20 ft of cement on top of the plug. Water-based muds or brines containing a plugging gel, with a density of at least 9.2 lb /gal should be used during plugging operations, and should remain between plugs in the well after cement plug placement.



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APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is needed.

STATEMENT OF BASIS

NAUTILUS POPLAR LLC
EPU 114
ROOSEVELT COUNTY, MT

OEP PERMIT NO. FPT2308-0870

CONTACT: Fort Peck Assiniboine and Sioux Tribes
Office of Environmental Protection
603 Court Avenue, Box 1027
Poplar, Montana 59255
Phone: 406.768.5155

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

OEP UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. OEP UIC permit conditions are based upon the authorities set forth in regulatory provisions at Title XXII CCOJ Ch. 2, and address potential impacts to underground sources of drinking water. Under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(4), issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Title XXII CCOJ Ch. 2, 3, and 4, 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 (Title XXII CCOJ Ch. 2, 3, 4, and 5) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(5) and SubCh. 4, Sec. 231(d). The Permit is subject to OEP review at least once every five (5) years to determine if action is required under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(5).

PART I. General Information and Description of Facility

Nautilus Poplar LLC 1775 Sherman Street, Suite 1950 Denver, CO 80203

on

January 17, 2006

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

EPU 114 921' FEL 277' FSL, SESE S28, T29N, R51E Roosevelt County, MT

Regulations specific to Fort Peck Indian Reservation: Assiniboine & Sioux Tribes—Class II injection wells are found at 40 CFR 147 Subpart JJJ and at Title XXII Chapter 2 of the Fort Peck Tribes' Comprehensive Code of Justice.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with Title XXII CCOJ Ch. 2, was reviewed and determined by OEP to be complete.

The EPU 114 well was completed in 1997 as an oil well and converted to a salt water disposal well. An EPA UIC permit was issued on August 1, 2007 for disposal of produced water from the Madison and Charles and Heath formations. The brine water produced from the East Poplar Oilfield ranges from 25,000 to 225,000 mg/L total dissolved solids (TDS).

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

TABLE 1.1

WELL STATUS / DATE OF OPERATION

NEW WELLS

Well Name	Well Status	Date of Operation
EPU 114	New	N/A

PART II. Permit Considerations (Title XXII CCOJ Ch. 2, SubCh. 4, Sec. 231(n))

Hydrogeologic Setting

The majority of the Fort Peck Reservation is overlain by glacial and/or alluvial deposits and the water table aquifer is relatively shallow. Domestic wells in the area are often installed in this shallow aquifer.

Major producing oil bearing formations within the reservation include the Charles and Mission Canyon, Nisku, and Duperow.

Geologic Setting (TABLE 2.1)

Flaxville Formation/Alluvial Glacial – mainly valley fill consisting of silt, sand and gravel; includes some terrace deposits and glacial drift of Pleistocene age. The glacial till, gravel deposits and alluvium overlay the Hell Creek formation.

The Hell Creek Formation is a series of fresh and brackish-water clays, mudstones, sandstones deposited during the last part of the Late Cretaceous-Tertiary period. The lithology consists of gray sandstone and greenish shaly clay and mudstone containing dinosaur bones. There are a few thin lignite and subbituminous coal beds.

The Fox Hills Sandstone is of Late Cretaceous age. It is typically shaly sandstone grading upward into massive brownish sandstone with white sandstone of the Colgate member locally at the top. The Fox Hills Formation overlies the Bearpaw Shale.

The Bearpaw Shale contains shale, sandstone and claystones with numerous betonite seams of Late Cretaceous age. The Bearpaw consists of dark-gray and brownish clay/shale, thick units of nonfissile bentonitic shale and calcareous and ferruginous concretions throughout. The Bearpaw Shale overlies the Judith River.

The Judith River formation if primarily composed of light colored sandstones, somber-gray sandy shales, and siltstones. Some mudstones and coals are evident. The Judith River is of Late Cretaceous age and overlies the Claggett Formation.

The Eagle Sandstone is Late Cretaceous in age. It consists of sandstone, shaly sandstone with interbeded lignite stringers. The eagle Formation overlies the Telegraph Creek Formation.

The Greenhorn Formation is Late Cretaceous in age and is marine deposited. The Greenhorn consists of light gray marly and calcareous shale and chalk, occasional limestone nodules.

The Dakota Silt is Early Cretaceous in age. This silty section is nonporous and nonpermeable and creates a good confining zone above the Dakota Sand. There are several shale zones in addition to the Dakota Silt which provide confinement between the Dakota Sand and the nearest up hole USDW including the Mowry, Greenhorn, Niobrara and the Telegraph Creek.

The Dakota Sandstone is of Early Cretaceous Age and has been deposited in both marine and non-marine environments. The Dakota Sand in this area consists of widespread alternating series of porous sands and shale layers. The porous sand lobes vary in thickness from 6 to 16 feet and porosities range from 18 to 27 percent which make this zone suitable for fluid injection. The Dakota Sand overlies the Kootenai Fuson Formation.

The Kootenai Formation is Early Cretaceous in age and consists of silty shale and mudstones purplish and green in color. This silty shale/mudstone creates a confining zone between the

Dakota Sandstone and the Lakota Formation.

The Swift Formation is Late Jurassic in age and consists of dark gray-greenish gray shale interbedded with siltstone. The Swift is a good confining zone below the Lakota injection zone.

The Rierdon Formation is Late Jurassic in age and consists of alternating gray to dark gray limy shale and limestones. The thin calcareous to noncalcareous beds contain dense nodular limestone. The Rierdon overlies the Piper Silt.

The Piper Formation is Middle Jurassic in age and includes red beds, gypsum, and associated marine beds underlying the Rierdon Formation. The Piper consists of the red siltstones and gypsum grading into gray shale, limestone. The Piper Formation overlies the Spearfish Formation. The Firemoon member is an interval of bioclastic carbonate and green calcareous shales.

Kline is a member that consists of limestone and shale.

The Spearfish Formation is Permian and Triassic in age and was marine deposited. The Spearfish can be divided into the Saude, Pine Salt and a lower shale member. The Spearfish Formation consists of red, sandy clay or shale with some gypsum. Fissile gray shale can be interbedded with reddish-orange siltstone and mudstone with anhydrite and dolomite beds. The Spearfish unconformably overlies the Amsden Formation.

The Madison Group includes the Charles, Mission Canyon and the Lodgepole Formations and is Early to Late Mississippian in age. The depositional environment was marine and consists of interfingering carbonate and evaporite sequences.

The Madison Group includes the Charles, Mission Canyon and the Lodgepole Formations and is Early to Late Mississippian in age. The depositional environment was marine and consists of interfingering carbonate and evaporite sequences.

TABLE 2.1
GEOLOGIC SETTING
EPU 114

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Alluvium/Glacial Deposits	0	150	< 10,000	Sand, Gravel
Bearpaw	150	836		Shale
Judith River	854	1,261	> 10,000	Sandstone
Eagle	1,261	2,124		Sandstone
Niobrara	2,122	2,458		Shale, Siltstone
Green Horn	2,458	2,660		Calcareous Shale, Chalk
Muddy	2,660	3,005		Shale, Siltstone,Sandstone
Skull Creek	3,005	3,227		Shale
Dakota Sandstone	3,227	3,630	7,180	Sandstone
Morrison	3,630	3,670		Shale, Sandstone, Siltstone
Swift	3,670	4,184		Shale, Siltstone
Rierdon	4,005	4,360		Shale, Limestone
Piper	4,360	4,433	55,000	Siltstone, Limestone
Piper Limestone	4,433	4,700		Dolomitic Limestone
Spearfish	4,700	4,819		Shale
Amsden	4,819	4,952	60,000	Limestone, Sandstone
Tyler	4,952	5,000	60,000	
Otter	5,000	5,200		Shale
Kibbey	5,200	5,444		Sandstone, Limestone
Charles	5,444	5,534	50,000 -	Dolomite/Anhydrite Interbeds
Charles "A" and "B-1" Porosity	5,534	5,709	84,000	Limestone
Charles Dolomite	5,868	6,060	84,000	Dolomite
Mission	6,060	6,600	84,000	Limestone
Lodgepole	6,600	7,188		Limestone, Chalk
Bakken	7,188	7,222		Shale, Siltstone
Three Forks	7,222	7,295		Shale, Siltstone
Nisku/Birdbear	7,295	7,377	115,000 -	Limestone
Duperow	7,377	7,797		Limestone

Proposed Injection Zone(s) (TABLE 2.2)

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

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

The approved injection zone provided in the original permit issued by EPA Region 8 includes the Charles “A” and “B” porosity (5534’ to 5729’), Mission Canyon (6060’- 6600’), and Nisku (7295-7377). Water samples from the injection zone is reported to be 100,000 mg/L TDS or greater and an aquifer exemption for this formation is not needed.

TABLE 2.2
INJECTION ZONES
EPU 114

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Charles "A" and "B-1" Porosity	5,534	5,709	84,000	0.680		N/A
Mission	6,060	6,600	84,000	0.680		N/A
Nisku/Birdbear	7,295	7,377	115,000	0.680		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)

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

There are several formations above the injection zone that serves as barrier to fluid movement. The Bear Paw Shale resides below the Pleistocene Glacial Tills and above the Judith River. A series of shale in the Upper and Lower Cretaceous rock can be found below the Judith River and the Dakota (Niobrarra, Greenhorn, Belle Forche and Skull Creek). Between the injection zone and the Dakota is the Jurassic sequence (Swift, Rierdon, Piper, Piper Limestone) which consists of approximately 1,100 feet of shale, sandstone, limestone, dolomite, and anhydrite, over 100 feet of red sandstone, siltstone, and shale of the Triassic Spearfish Formation, and an additional 100 feet of purplish dolomite and greenish gray shale of the Pennsylvanian Amsden formation.

The uppermost 100 feet of the Charles formation is predominately anhydritic carbonates to provide a confinement above the injection zone (5444-5534 feet).

TABLE 2.3
CONFINING ZONES
EPU 114

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Charles	Dolomite/Anhydrite Interbeds	5,444	5,534
Bakken	Shale, Siltstone	7,188	7,222
Duperow	Limestone	7,377	7,797

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

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

Most aquifers producing potable water on the Fort Peck Indian Reservation are stream alluvium (valley-fill deposits), outwash sand and gravel, pre-glacial alluvial deposits of Pleistocene age, Flaxville Formation, Fort Union Formation, and Fox Hills and Hell Creek Formations. All of these sources are within 1000 feet of the surface on the reservation. Most wells are found at shallow depths, with few deeper than 250 feet.

There is a limited amount of data on the water quality and the hydrology of the Judith River Formation (JRF). Based on structural geology of the Fort Peck area and the location of the outcrop of the JRF, the direction of the groundwater flow is most likely from the west to the east and southeast. Water quality data indicate an increase in TDS from west to east. The 1985 US EPA report titled Undergound Injection Activities in to the Judith River on the Fort Peck Reservation: Statement of Policy & Technical Evaluation, the Judith River is determined not to be an USDW in the Poplar Field. A sample collected in 1957 from the Judith River at 877 feet deep in T29N, R51E sec 19 found the TDS to be 18,624. Available data indicate that the Judith River Formation in the vicinity of the Volt and Tule Fields was an USDW prior to injection activities.

At depths greater than 1000 feet, the Judith River Formation, Lakota or Kootenai Formation (also called the Dakota), and Madison group are known to be aquifers. Historically, these units have been used as receiving aquifers for injection of brines and other oilfield wastes and contain water of high salinity. The TDS in the area can vary locally in the East Poplar Oil Field, according to Robert Bergantino of Montana Bureau of Mine and Geology. In a publication authored by Robert Bergantino, titled "Groundwater in pre-Bearpaw Shale aquifer in Wolf Point in One Degree by Two Degree Quadrangle Northeast Montana and Adjacent North Dakota", Montana Atlas 5G, 1994, the report provided a water quality sample in the Fall River formation of 7,180 mg/L TDS. The Fall River is a sandstone which is technically the lower portion of the Skull Creek. Dr. Bergantino believes that it is also very likely the underlying Dakota sandstone formation has TDS values similar to that of the Fall River. For simplicity, the Fall River and Dakota is considered one unit. The water quality sample was taken in 1957 in T29N, R50E, Section 12. Since then millions of barrels of produced water have been injected into the Dakota formation and it is possible that locally the water quality has been degraded such that the TDS is greater than 10,000 mg/L. In the absence of site specific information and the availability of historical data indicating that the Dakota is a USDW, the Dakota is designated as the lowermost USDW.

TABLE 2.4

UNDERGROUND SOURCES OF DRINKING WATER (USDW)

EPU 114

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Alluvium/Glacial Deposits	Sand, Gravel	0	150	< 10,000
Judith River	Sandstone	854	1,261	> 10,000
Dakota Sandstone	Sandstone	3,227	3,630	7,180

PART III. Well Construction (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(e))

TABLE 3.1

WELL CONSTRUCTION REQUIREMENTS

EPU 114

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Tubing		3.00	-	-
Surface	12.25	9.63	0 - 976	0 - 976
Longstring	8.75	7.00	0 - 7,661	4,145 - 7,661

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under Title XXII CCOJ Ch. 2 SubCh3. Sec 221(b)(9) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

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

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

Tubing and Packer

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

Tubing-Casing Annulus (TCA)

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

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

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

PART IV. Area of Review, Corrective Action Plan (Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(12) and (13))

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
EPU 42	Producer	No	5,890	4,700	No
EPU 57	Producer	No	8,920	4,520	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well. If TABLE 4.1 is not included in this document, then there are no Area of Review wells for this injection well.

Area Of Review
Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(b) 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.

There are two oil and gas wells that were near the ¼ mile area of review. The EPU No. 42 was drilled to a total depth of 5889’ as a Charles production well and plugged back to 5853’. Perforations are open to the Charles “B-2” for production. The calculated top of cement is 4555’. EPU No. 57 was drilled to a total depth of 8920’. The well was plugged back to 5560’ and cement squeezed through the Charles “B” and “C” formations. The calculated top of cement is 4357’. This well is slightly outside of the ¼ mile AOR and was reviewed.
CBLs are not available for review for either well to verify cement quality. However, EPU No. 42 is

expected to have adequate zonal confinement because the cement near the base of the casing when cement is first circulated is expected to provide the best cement bond. The EPU No. 57 has had multiple squeeze through the Charles “B” and “C” formations to provide isolation of fluids injected through the injection zones.
A search of the Montana Bureau of Mines and Geology Groundwater Information Center database yielded no drinking water wells within a 1/2 mile radius of the injection well.
There are no known or identifiable faults in the area of review.
No corrective action is needed for this permit.

Corrective Action Plan

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

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

PART V. Well Operation Requirements (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(f))

TABLE 5.1
INJECTION ZONE PRESSURES
EPU 114

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Charles "A" and "B-1" Porosity	5,534	0.680	1,125
Mission	6,060	0.680	1,230
Nisku/Birdbear	7,295	0.680	1,485

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to Title XXII CCOJ Ch. 2, SubCh. 1, Sec. 204(1), (2), and (3). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

Injection Pressure Limitation

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

The injection formation in the original permit issued by EPA was initially set at 2000 psi based on other MAIP provided in these injection zones. A Step Rate Test (SRT) was required as part of the initial permit. The SRT results were not conclusive as fracture pressure was not reached and a bottom hole pressure gauge was not used. The instantaneous shut-in pressure was recorded as 800 psi. The MAIP was adjusted to 800 psi when the permit was given the authorization to inject. The new MAIP will be set based on the default fracture gradient for this area of 0.68 psi/ft. The new MAIP will be the smallest pressure of the three approved injection zones.

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

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

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

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

Injection Volume Limitation

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

Mechanical Integrity (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(c))

An injection well has mechanical integrity if:

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

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and every five (5) years thereafter in accordance with Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(c). A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The results of the test shall be submitted to the Director no later sixty (60) after the demonstration, unless the test is witnessed by a representative of OEP.

Part I (Internal) MI will be demonstrated prior to beginning injection and at least once every five (5) years after the last successful demonstration of Part I MI. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing, or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, whichever is less, with ten (10) percent or less pressure loss over thirty (30) minutes.

The cement bond long (CBL) was analyzed and it was determined that adequate cement exists behind pipe to prevent significant movement of fluid out of the approved injection zone of the annulus cement, i.e., 80% bond index cement bond across the confining zone.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

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

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

PART VII. Plugging and Abandonment Requirements (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(d))

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (OEP Form FPT-UIC-4-0109) 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 (Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(a))

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The 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.

Initially, the operator has chosen to demonstrate financial responsibility with:

Surety Bond, received June 7, 2013

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