# FORT PECK OFFICE OF ENVIRONMENTAL PROTECTION

# UNDERGROUND INJECTION CONTROL PROGRAM

# PERMIT

PREPARED: May 2022



**Permit No. FPT2002-1169**

Class II Salt Water Disposal Well

**EPU 133H**
**ROOSEVELT, MT**

Issued To

**POPLAR RESOURCES LLC**
PO BOX 547
POPLAR, MT 59255

# 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,

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| POPLAR RESOURCES LLC<br>PO BOX 547<br>POPLAR, MT 59255 |

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

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| EPU 133H<br>T28N R51E S10, NWNE<br>ROOSEVELT, 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 ____________________

____DRAFT______________________________
Martina Wilson
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 shutoff 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.

(a) The Permittee must submit to the Director a notice of completion of construction and a completed OEP Form FPT-UIC-1-0109 or 2-0109 and complete all applicable logging and testing requirements of this Permit (see APPENDIX B) and submit the records 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 must be demonstrated; and

(i) The Director will inspect or otherwise review the new well construction and determine if it is in compliance with the conditions of the Permit; or

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

(iii) The Director has reviewed the testing results and issued a written authorization to inject.



***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) Injection pressure at the wellhead shall not initiate new fractures or propagate existing fractures in the confining zone. In no case shall injection pressure cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by EPA, injection pressure shall not exceed the MAIP. The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP**)** plus friction loss.

**MAIP** = **FP** + friction loss (if applicable)

The **FP** (measured at the surface) must be calculated using the following equation:

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

The values used in the equation are defined as:

**“FG”** is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to the determine a representative **FG** may be used, if approved by the Director.

**“SG”** is the specific gravity of the injection fluid obtained from a representative fluid sample.

**“D”** is the true vertical depth in feet. The value for **D** is the depth of the top open perforation.

The current permitted Maximum Allowable Injection Pressure (MAIP) is found in APPENDIX C. This MAIP is calculated using the equation above and data submitted with the permit application.

(c) To determine the MAIP, the Permittee shall submit prior to authorization to inject the following for review: step rate test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in APPENDIX A, that specifies the depth to top perforation.) The MAIP shall be calculated as described above. The Director will review the information and provide the MAIP in the written authorization to commence injection.

(d) During the life of the Permit, the fracture gradient, top perforation depth, and specific gravity may change. When new perforations are added to the injection zone, the Permittee shall demonstrate that the FG previously submitted is also appropriate for the new interval within the injection zone. It may be necessary to run a new step rate test to gather information from the new interval proposed for injection. Upon submission of monitoring reports, tests, or well workover records that indicate one of these parameters has changed, the MAIP calculation will be evaluated.

When the D or FG value changes, a new MAIP shall be recalculated. When a sample analysis is submitted, the newly submitted SG value will be compared to the SG used to calculate the MAIP. If the absolute difference is greater than 0.05, the MAIP will be recalculated using the newly submitted SG value.

To approve an increase to the MAIP, as a result of changes to the D or FG values, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

The Director will notify the Permittee in writing of the revised MAIP. A newly calculated MAIP shall not be implemented until written approval is received from the Director.

(e) Tests to demonstrate external (Part II) Mechanical Integrity (MI) shall be conducted at the most recently approved MAIP. However, if during testing, the Permittee is unable to achieve the MAIP, the MAIP will be readjusted and set to the highest pressure achieved during the successful external (Part II) Mechanical Integrity Test (MIT). The Permittee will be notified in writing from the Director of the new MAIP, based on the Part II MIT results.

***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 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. This well is not approved for commercial disposal ( oil and gas production waste fluids generated by a third party, transported to well site by tank truck, and accepted for a fee or compensation) or other fluid disposal operations.

The Permittee may inject fluids that meet the criteria above. However, prior to introduction of a new source ( e.g. different production formation, well field, operator, or other approved injection fluids for Class II, including non-hazardous gas plant waters integral to production operations, etc.) into the well, a fluid analysis shall be required, as listed in Appendix D under "PRIOR TO AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE". The Permittee shall provide notification to the Director as well as provide a representative sample of the new injection fluid, as required in APPENDIX B. Results of the fluid analysis may affect the MAIP as described above in Part II, Section B.4 Injection Pressure Limitation.

***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 all sources of the fluids injected during the year must identify each source by the generator's name and the 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 occurrence 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 133H was originally drilled to a total measured depth of 11,553 feet and a total vertical depth (TVD) of 7,126' to produce oil and gas from the Bakken and Three Forks formations. Poplar Resources will recomplete the well in the Dakota Formation with perforations from 3,230 to 3,572 feet in depth. Poplar Resources will plug back the well with the two following plugs:

Plug #1: Production Zone

- Set a cast iron cement retainer (CICR) at 6,250 feet depth.
- Cement below retainer with 200 sacks class G cement.
- Place 5 sacks cement on top of CICR.
- Top of cement plug will be at +/- 6161 feet depth.
- At +/- 5970 feet depth place 50 sacks class G cement balance plug.

Plug #2: Plug back below Dakota Injection Zone

- Set a cast iron bridge plug (CIBP) at 3,772 feet.
- Pump 9 sacks class G cement above CIBP.
- Top of cement plug will at 3,722 feet depth within the vertical portion of the well.

Surface Casing: A 13.375 inch casing was set at 1,082 feet in a 17.500 inch hole and cemented to surface with 1107 sacks of cement.

Longstring Casing: A 9.625 inch casing was set at 6,320 feet in a 12.250 inch hole and cemented with 1,390 sacks of cement. The CBL identified the TOC at 2,058 feet, however, 80% bond only occurs between the following intervals above the top of the proposed injection zone:

- 2,058 - 2,962.4 feet
- 2,853 – 2,857.4 feet
- 2,084 - 2,091.7 feet

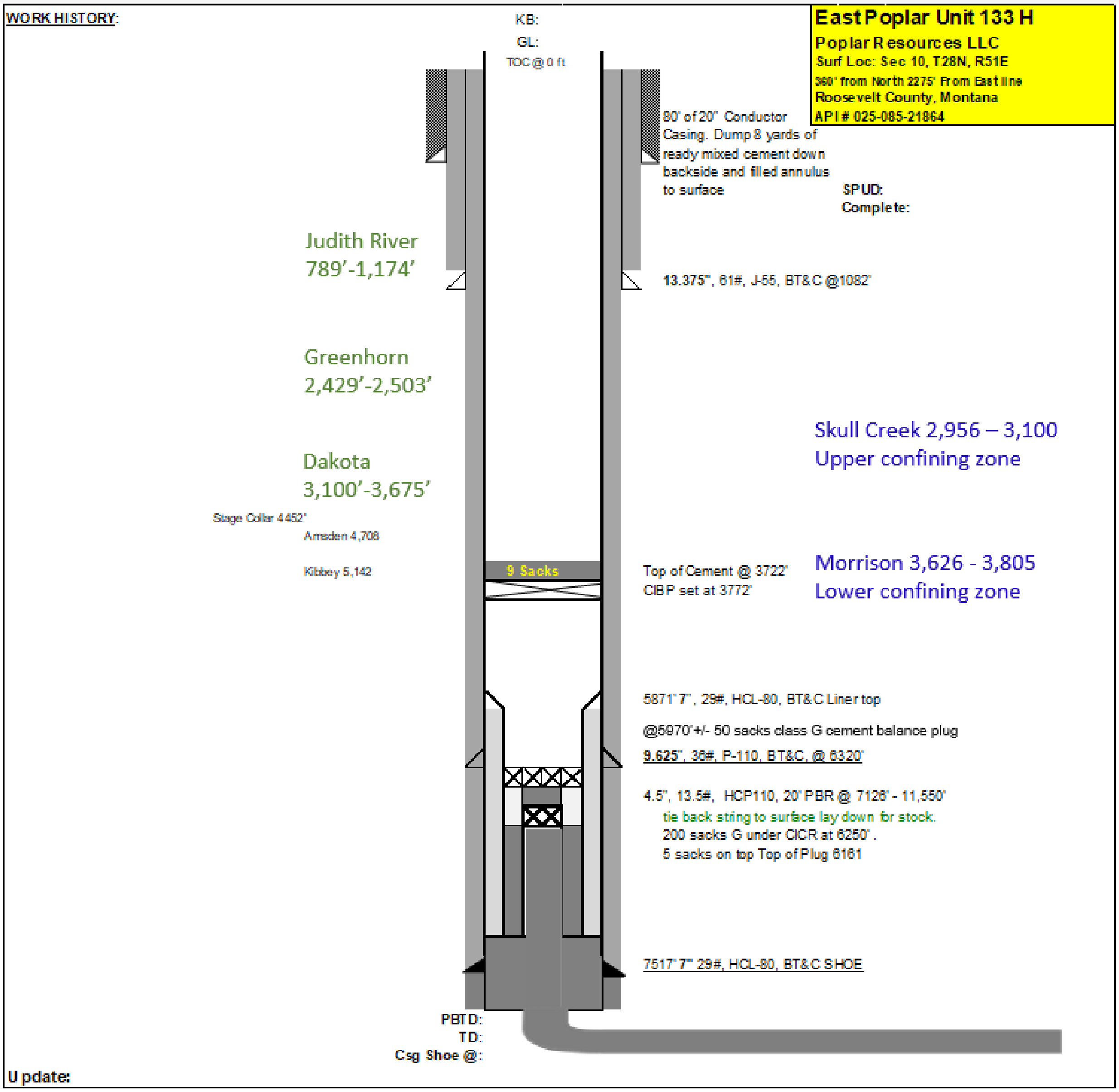
Tubing: (TBD) inch set at (TBD) feet.

Note: Packer must be set no more than 100 feet above the top perforation.

Injection Zone: Dakota Formation from 3,100 - 3,626 feet.

Perforations into the Dakota Formation:
3,230' to 3,572' (proposed)

## Proposed Well Construction Diagram



# APPENDIX B

## LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to the EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Well logs and test results shall be submitted to the Director within sixty (60) calendar 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 log or test results. When applicable, the report shall include a descriptive report prepared by a knowledgeable log analyst, interpreting the results of that portion of those logs and tests which specifically relate to (1) a USDW and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

| **WELL NAME:** EPU 133H | |
|---|---|
| **TYPE OF TEST** | **DATE DUE** |
| **Well logs and test results shall be submitted to the Environmental Programs Manager within thirty (30) calendar days of completion of the logging or testing activity** | |
| Standard Annulus Pressure | Injection Well: A Part I demonstration of internal mechanical integrity shall be conducted prior to receiving authorization to inject and at least every 5 years thereafter.<br>Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. |
| Radioactive Tracer Test | Injection Well: A Radioactive Tracer Test shall be conducted prior to receiving authorization to inject as an initial Part II demonstration of external mechanical integrity. |
| Temperature Log | Injection Well: An initial baseline temperature log shall be conducted prior to receiving authorization to inject.<br>A follow-up temperature log shall be conducted after 6 months of injection activity. Results shall be compared to the baseline temperature log as a Part II demonstration of external mechanical integrity.<br>A temperature logs shall be conducted least every 5 years thereafter. Results shall be compared to the baseline temperature log as ongoing Part II demonstration of external mechanical integrity.<br>A temperature log shall be conducted prior to recommencing injection after any well rework that compromises the external mechanical integrity of the well or a loss of MI. |
| Bradenhead Monitoring | AOR EPU 12 API# 085-05049: Within 30 days of the effective date of the permit. Any variances in pressure shall be reported to OEP within 24 hours. |

# APPENDIX B

| | |
|---|---|
| Bradenhead Monitoring | Injection Well: Prior to commencing injection and every 30 days after. Any variances in pressure shall be reported to OEP within 24 hours. |
| Step Rate Test | Injection Well: A step rate test is required to obtain authorization to inject. Must follow guidelines (https://www.epa.gov/sites/production/files/2015-08/documents/r8_guideline_-_step_rate_testing.pdf) |
| Injectate Water Analysis | Injection Well: Annually and prior to introduction of a new source. |
| Injection Zone Water Sample | Injection Well: Prior to receiving authorization to inject.<br>A representative water sample from each discrete injection zone shall be analyzed. After a minimum of three successive pore volumes, a representative sample shall be determined by stabilized specific conductivity.<br><br>The sampling procedure should follow immediately after perforating an interval in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water. |
| Injection Formation Fluid Pressure | Injection Well: Prior to receiving authorization to inject. |

# 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) |
|---|---|
| EPU 133H | Will be determined according to Part II, Section C.3 after the step rate test has been conducted per requirements |

**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 133H | | | |
|---|---|---|---|
| | APPROVED INJECTION INTERVAL (KB, ft) | | FRACTURE GRADIENT (psi/ft) |
| FORMATION NAME | TOP | BOTTOM | |
| Dakota | 3100 | 3575 | Will be determined by step rate test |

**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.

After the well is perforated in the Dakota injection zone, the Permittee must collect a representative fluid sample to determine the TDS of Dakota aquifer fluids. If the TDS is less than 10,000 mg/L, an aquifer exemption will be required for injection into the Dakota. If an aquifer exemption is required and approved for this Permit, then the Director will set a volume limit based on the conditions of the aquifer exemption, through the modification process.

# 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.**

<table>
<tr><th colspan="2">OBSERVE WEEKLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS</th></tr>
<tr><td rowspan="6">OBSERVE AND RECORD</td><td>Injection Tubing Pressure (psi)</td></tr>
<tr><td>Annulus Pressure(s) (psi)</td></tr>
<tr><td>Bradenhead Pressure (psi)</td></tr>
<tr><td>Injection rate (bbl/day)</td></tr>
<tr><td>Injection Volume (bbl)</td></tr>
<tr><td>Cumulative Fluid Volume Injected (since injection began) (bbls)</td></tr>
<tr><th colspan="2">PRIOR TO AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE</th></tr>
<tr><td>ANALYZE</td><td>Analyze a sample of injection fluids at the sampling point for the following constituents:<br>• Total Dissolved Solids (mg/L) via Method 2540 C-97<br>• pH via Method 4500-H+ B-00<br>• Specific gravity via Method SM 2710 F<br>• Conductivity/Specific Conductance (S/m) via Method 2510 B97<br>Alternative analysis methods may be used, if pre-approved</td></tr>
<tr><th colspan="2">ANNUALLY</th></tr>
<tr><td>ANALYZE (if injection occurred during reporting period)</td><td>Analyze a sample of injection fluids at the sampling point for the following constituents:<br>• Total Dissolved Solids via Method 2540 C-97<br>• pH via Method 4500-H+ B-00<br>• Specific gravity via Method SM 2710 F<br>• Conductivity/Specific Conductance via Method 2510 B-97<br>Alternative analysis methods may be used, if pre-approved</td></tr>
</table>

| ANNUALLY | |
|---|---|
| **REPORT** | Each month's maximum and averaged injection tubing pressures (psi) |
| | Each month's maximum and minimum annulus pressure(s) (psi) |
| | Each month's maximum and minimum bradenhead pressures (psi) |
| | 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, including any wellfield and formation, noting any major changes in characteristics of injected fluid. |
| **AT 5-YEAR INTERVALS** | |
| **ONGOING DEMONSTRATION OF MECHANICAL INTEGRITY** | A Part I Standard Annulus Pressure test to demonstrate internal mechanical integrity shall be conducted:<br>• Within 5 years of the previous test;<br>• Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well; or<br>• After any well rework to correct a loss of internal MI. |
| | A Part II Temperature log to demonstrate external mechanical integrity shall be conducted:<br>• Within 5 years of the previous test;<br>• Prior to recommencing injection after any well rework that compromises the external mechanical integrity of the well; or<br>• After any well rework to correct a loss of external MI. |

**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

Prior to plugging the well, run a Mechanical Integrity Test, pull tubing and packer, and repair any casing leaks.

Notify OEP and MBOG

Prior to plugging the well, notify OEP and MBOG, run a Mechanical Integrity Test, pull tubing and packer, and repair any casing leaks necessary for abandonment.

At a minimum, the following plugs are required:

PLUG 1: Former Production Zone
(required for conversion to injection well)
Set CICR at 6,250 feet depth; pump 200 sacks class G cement below it; pump 5 sacks above CICR; top of cement plug will be at +/- 6,161 feet depth; at +/- 5970 feet depth place 50 sacks class G cement balance plug.

PLUG 2: Plug back to the base of the Dakota
(required for conversion to injection well)
Set CIBP at 3,772 feet depth; pump 9 sacks class G cement above CIBP; top of cement plug will be at 3,722 feet depth within vertical portion of the well.

PLUG 3: Dakota
Set CICR at 50'-100’ above top perf (3,130'-3,180’)
Pump enough cement below it squeeze all perfs and down to PBTD.
Place at least 5 sacks on top of CICR.

PLUG 4: Greenhorn
Set CICR. Use class G cement for plug extending 50 feet above and below the Greenhorn Formation both inside and outside the longstring casing.

PLUG 5: Judith River
Set CICR. Use class G cement for plug extending 50 feet above and below the Judith River Formation, both inside and outside the longstring casing, isolating across surface casing shoe.

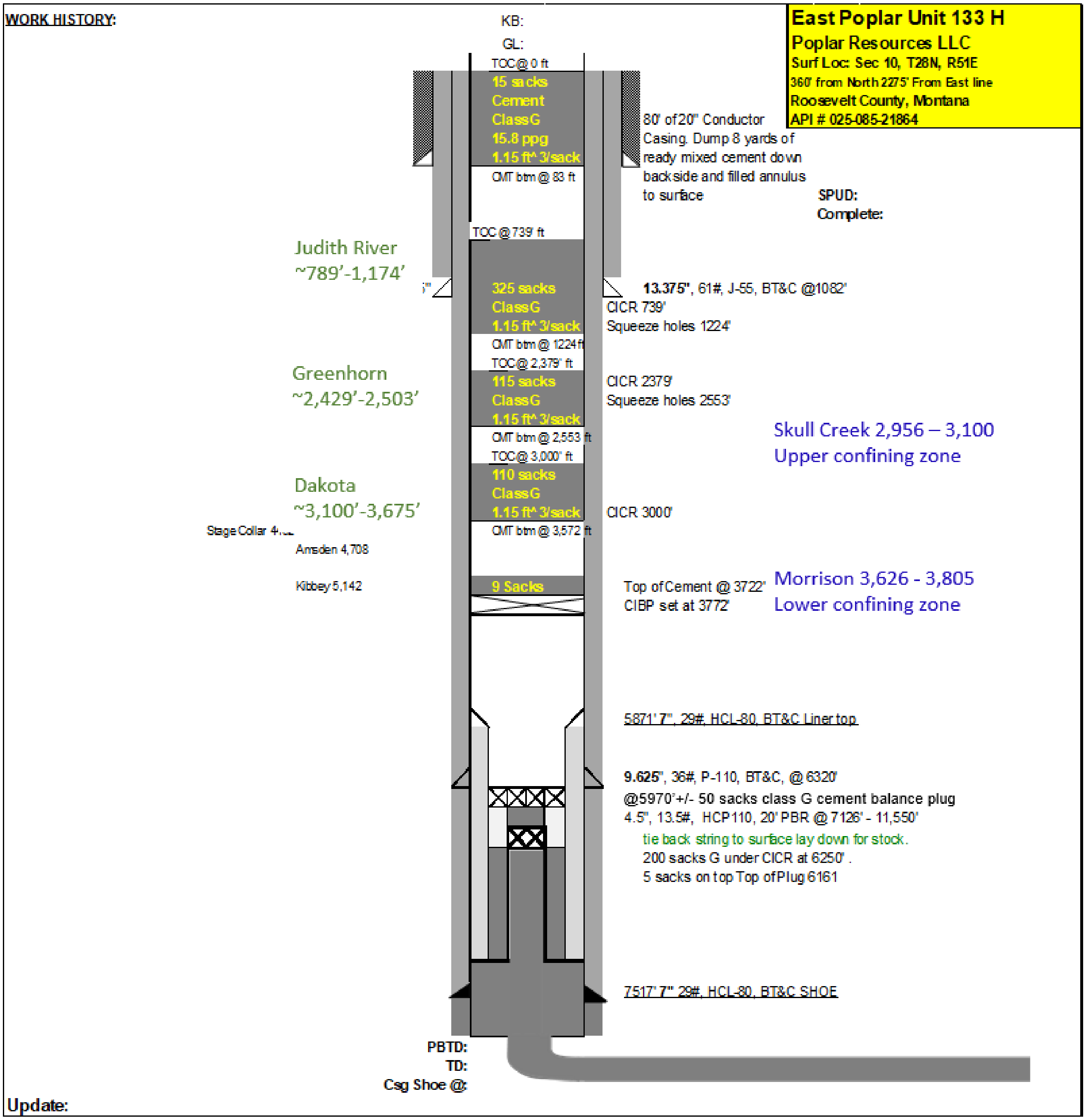
PLUG 6: Surface
Circulate enough sacks of Class G cement into top 50 feet of wellbore both inside and outside the longstring casing.

Cut off below ground level and weld a dry hole marker to top of surface casing.

NOTES:
Plug placement must be verified by tagging the top of the plug after the cement has had adequate time to set.

Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal should be used during operations, and should remain between plugs in the well after cement plug placement.

# Plugging Diagram



# APPENDIX F

# CORRECTIVE ACTION REQUIREMENTS

No corrective action is required.