UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
UNDERGROUND INJECTION CONTROL

DRAFT PERMIT

MT52439-12514

Class V Industrial Well

Jody Field 34-2
Pondera, Montana

Issued To

Montalban Oil & Gas Operations, Inc
33 1st Ave SW
Cut Bank Montana 59427-2937

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AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this permit (Permit),

Montalban Oil & Gas Operations, Inc
33 First Avenue SW
Cut Bank Montana 59427-2937

hereinafter referred to as the "Permittee," is authorized to construct and, upon issuance of authorization to commence injection, to operate, the following Class V well(s):

Jody Field 34-2
S34, T29N, R6W
Latitude: 48.228191
Longitude: -112.376628
Pondera, Montana

This Permit is based on representations made by the Permittee and other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subparts D and E, certain conditions apply to all UIC permits and must be incorporated either expressly or by reference. Regulations specific to Montana injection wells are found at 40 CFR § 147 Subpart BB. The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit into the above referenced well(s) is prohibited.

This Permit is issued for 10 (ten) years from the Effective Date, until it expires under the terms of the Permit, or unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41.

Issued Date __DRAFT_____________   Effective Date _DRAFT______________

____

Sarah Bahrman, Manager
Safe Drinking Water Branch
Water Division

SECTION A. WELL CONSTRUCTION REQUIREMENTS

The EPA-approved well construction plan is given in ATTACHMENT I of this Permit. The Permittee must comply with ATTACHMENT I, as approved by the Director. Once construction has begun, the Permittee must notify the Director within 30 days of the start date.

After initial construction of the well, the Permittee may make changes consistent with permit conditions. If these changes result in changes to the well construction schematic, notification must be provided to the Director. Such changes must be approved via written correspondence from the Director. Upon approval, the Permittee must comply with such changes, and such changes constitute enforceable requirements of this Permit. The Director may determine that a permit modification is needed to implement a proposed change. Changes to the approved well construction plan must not be implemented until after the Permittee has received approval from the Director.

1. Casing and Cement

The well(s) must be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.22. Additional federal, tribal, state, or local laws or regulations may also apply.

The casing and cement used in the construction of the well must be designed for the life expectancy of the well.

2. Injection Tubing and Packer

Injection must only take place through tubing with a packer set within or below the nearest cemented and impermeable confining system according to the specifications in ATTACHMENT I of this Permit. Any proposed changes must be submitted by the Permittee in accordance with Section B.8. *Alteration, Workover, and Well Stimulation* of this Permit.

3. Sampling and Monitoring Devices

The Permittee must install and maintain in good operating condition any and all devices required to measure, monitor, and record the parameters required by this permit in ATTACHMENT III and ATTACHMENT IV. Requirements for monitoring devices are found in ATTACHMENT I.

The Permittee must ensure that the devices and methods installed and used are sufficient to represent the activity being measured, monitored, or recorded. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a back-up system for when primary continuous monitoring devices malfunction or power outage occurs. The Permittee must ensure the well construction and near-wellhead design is appropriate for collecting fluid samples and fulfilling all monitoring requirements. The Permittee must ensure all gauges used for monitoring and testing are calibrated as appropriate.

4. Pre-Injection Logs and Tests

Well logging and testing requirements prior to receiving initial authorization to commence injection are found in ATTACHMENT V. Well logs and tests must be performed according to current EPA-approved procedures or alternate procedures approved by the Director. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. Limited injection is permissible prior to receiving initial authorization to inject only for the purposes of conducting the initial well logs and tests required in ATTACHMENT V.

5. Postponement of Construction or Conversion to Injection Wells

(a) If well construction has not commenced:

(i) The Permit expires two years from the “Effective Date” unless the Permittee requests and receives written approval for an extension from the Director. The Permittee is allowed a maximum of two extensions at the Director’s discretion, not to exceed six years after the “Effective Date” to construct the well. The Director may further limit the number of and/or duration of extensions.

(ii) A request for extension must be in writing and received prior to the applicable permit expiration date. The request must state the reasons for the delay, provide an estimated well completion date, and list any additional wells within the area of review (AOR) that have not been previously identified. The request must also include well construction diagrams, cement records, and cement bond logs for these wells within the AOR that penetrate the overlying confining zone. If no such wells exist, the Permittee must certify this in writing.

(iii) For requests submitted in accordance with this section, the Permit remains in effect unless the Permittee receives written notice from the Director stating that the Permit has expired or is otherwise not extended.

(iv) Once the Permit has expired, the Permittee must reapply for a UIC permit and restart the complete permit application process, including opportunity for public comment, if intending to use the well(s) for the purposes of injection.

(b) If well construction has begun before the Permit has expired in accordance with this section and the Permittee has not received authorization to commence injection, the Permittee is subject to the conditions found in Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Section F.2. *Injection Well Conversion*.

SECTION B. WELL OPERATION

1. Annular Injection Prohibition

Injection into any annulus formed between casings serving as surface, intermediate, or long string casing, or between any casing and the wellbore is prohibited.

2. Requirements Prior to Receiving Initial Authorization to Commence Injection

Well injection may commence only after the Permittee has received written authorization to inject from the Director and has met all well construction and pre-injection requirements, including the following:

(a) The Permittee has:

(i) submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments or its equivalent. If the well construction is different than the approved construction found in ATTACHMENT I, the Permittee must also provide a revised well diagram and a description of the previously approved modification to the well construction;

(ii) conducted all applicable requirements found in ATTACHMENT III and ATTACHMENT V and submitted required records to the Director. The logging and testing requirements include demonstration of mechanical integrity (MI) pursuant to 40 CFR § 146.8(a) in accordance with the conditions found in Section C of this Permit; and

(iii) satisfied requirements for corrective action in ATTACHMENT VII, if applicable.

(b) The Director has received and reviewed the documentation associated with the requirements in paragraph 2(a) of this section and finds it is in compliance with the conditions of the Permit.

(c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. Such inspection is waived if the Permittee has not received notice from the Director of intent to inspect the injection well within 13 days of the date of the notice provided in paragraph 2(a)(i) above.

3. Injection Zone and Fluid Movement

Injection zone means “a geological formation, group of formations, or part of a formation receiving fluids through a well.” Injection may only occur within the approved injection zone specified in ATTACHMENT II and injected fluids must remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee must notify the Director within twenty-four (24) hours (Section I.11) and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

4. Injection Pressure Limitation

(a) Injection pressure at the wellhead must not initiate new fractures or propagate existing fractures in the injection zone, and must not cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or well tests approved by the Director, injection pressure must not exceed the MAIP.

(c) The **MAIP** is calculated using the equation below. The MAIP and data parameters used in calculating the MAIP are found in ATTACHMENT II. The MAIP as measured at the surface must equal the formation fracture pressure (FFP**)** plus friction loss, if applicable. Friction loss may be applied at the Director's discretion.

MAIP = **FFP** + **Friction Loss** (if applicable)

Friction Loss (psi) is pressure loss between the wellhead and the injection zone as a result of injection.

The **FFP** (measured at the surface) will be calculated using the following equation:

FFP = [***Fracture Gradient* -** (0.433 * (***Specific Gravity*** + ***SG Fluctuation Factor***))] * ***Depth***

Fracture Gradient (psi/ft) is the fracture gradient of the injection zone.

Specific Gravity (SG, unitless) is a ratio of the density of the injection fluid to the density of water at 4 degrees Celsius, obtained from a representative injection fluid sample.

SG Fluctuation Factor (SGFF, unitless) is added to the Specific Gravity to account for potential variations of the actual injected fluid specific gravity.

Depth (ft) is the measured distance as described in ATTACHMENT II.

(d) MAIP Changes

(i) After initial construction of the well, the MAIP may be recalculated based upon the completion report data.

(ii) Any time the injectate specific gravity value is greater than the (SG + SGFF) that was used to calculate the current MAIP, a new MAIP must be calculated according to the new value. Other data that may support a MAIP calculation include information about the injection zone fracture gradient, friction loss, and/or depth.

(iii) The recalculated MAIP per this section of the Permit must replace the MAIP value given in ATTACHMENT II of the Permit and will become effective and enforceable upon written correspondence from the Director. The Director may also determine that a permit modification is needed to implement the change.

(iv) The Permittee may request a change to the MAIP. The Permittee must submit documentation needed to reevaluate the MAIP to the Director for approval.

(v) The Director may determine that a MAIP lower than the MAIP calculated in 4(c) of this section is appropriate for the protection of USDWs.

5. Injection Volume Limitation

Injection volume is limited to the total volume specified in ATTACHMENT II.

6. Injection Fluid Limitation

Injected fluids are limited to those fluids described in ATTACHMENT II. Prior to introduction of a new source (e.g., different production formation, well field, etc.) into the well, the Permittee must provide notification to the Director. The notification must include a description of the fluid, the process that generated the fluid, and a representative sample of the new fluid source that provides an analysis of the constituents found in ATTACHMENT III. Analysis of additional constituents may be requested on a case-by-case basis. Results of the fluid analysis will be used to determine if a new MAIP is required. See Section B.4 *Injection Pressure Limitation*.

7. Tubing–Casing Annulus

The tubing-casing annulus (TCA), or the inner most annulus in the well, must be filled with a non-corrosive fluid or other fluid approved by the Director. Any wellhead TCA valve, if present, must remain closed during normal operations. The pressure at which the TCA must be maintained is found in ATTACHMENT II.

If wellhead TCA pressure cannot be maintained at the pressure found in ATTACHMENT II, the Permittee must report to the Director the actions taken to determine the cause and the proposed remedy. If a loss of MI has been determined, the Permittee must comply with the Loss of Mechanical Integrity requirements found in Section C.5.

8. Alteration, Workover, and Well Stimulation

Alterations, workovers, and well stimulations must meet all conditions of the Permit. Alterations, workovers, and well stimulations include any activity that physically changes the well construction (casing, tubing, packer) or injection formation. These actions are collectively called, “alterations” for the remainder of this section.

The Permittee must give advance notice to the Director prior to beginning an alteration to the injection well(s) or injection formation. This notice must be provided 30 days prior to the date of the planned alteration. At the Director’s discretion, a shorter notification period may be allowed. Additionally, the Director's prior written approval must be obtained if the alteration modifies the approved well construction. Alterations that fall outside of the minimum construction requirements in ATTACHMENT I will require a permit modification and may require additional testing or monitoring requirements.

The Permittee must record all alterations on a Well Rework Record (EPA Form 7520-19) and submit a revised well schematic and plugging and abandonment (P&A) plan, if necessary, when the well construction has been modified. The Permittee must submit these documents and other records of alterations, logging, or test data to the Director within 30 days of completion of the activity.

The Permittee must complete any alteration that affects the tubing, packer, or casing and provide demonstration of Internal MI as defined in Section C.1 within 90 days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee must propose an alternative schedule. Injection operations must not resume until Internal MI has been successfully demonstrated. If MI is lost, the Permittee must receive written approval from the Director to recommence injection in accordance with Section C.5 of this Permit.

9. Well Logging and Testing Requirements

Well logging and testing requirements are found in ATTACHMENT V. The Permittee must ensure that log and test requirements are performed within the time frames specified in ATTACHMENT V. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. The Permittee must provide the well logging and testing procedure prior to conducting any well log or test. It is the responsibility of the Permittee to conduct all well logging and testing requirements according to EPA approved procedures.

10. Area of Review and Corrective Action

The area of review (AOR) for this Permit is found in Attachment II and associated corrective action required within the AOR is found in Attachment VII. The Permittee has an on-going obligation as described in Attachment IV to identify and report any additional wells not previously reported within the AOR.

For any wells, that penetrate the confining zone within the AOR, which are improperly sealed, completed, or plugged and abandoned, the Director may require corrective action as is necessary to prevent movement of fluid out of the injection zone into USDWs.

SECTION C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure that injection well Mechanical Integrity (MI) is always maintained. Injection into a well that lacks MI is prohibited. An injection well must satisfy both Internal and External MI:

Internal MI - There is no significant leak in the casing, tubing, or packer; and

External MI - There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

2. Demonstration of Mechanical Integrity

The Permittee must demonstrate that the injection well(s) has established MI as defined in Section C.1. The Permittee must demonstrate MI on the following occasions:

(a) Prior to receiving authorization to commence injection in accordance with Section B.2 and periodically, thereafter as specified in ATTACHMENT V.

(b) After any alteration that compromises the MI of the well or after a loss or suspected loss of MI in accordance with Section C.5 *Loss of Mechanical Integrity*.

(c) As part of the plugging and abandonment of the well, in accordance with Section E and ATTACHMENT VI.

(d) As part of the conversion of the well to another type in accordance with Section F.2.

(e) Upon request of the Director.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate MI.

The Permittee must ensure that all gauges used in MI demonstrations are properly calibrated within one year prior to the test date. Use of a new gauge with proof of purchase will meet this requirement.

Results of any MI test required by this Permit and any additional documents required by the Director to support the test results must be submitted to the Director as soon as possible, but no later than 30 calendar days after the test is complete.

3. Mechanical Integrity Test Methods and Criteria

EPA approved methods must be used to demonstrate MI. EPA MI testing guidance can be found at:

https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. The Permittee must follow the prescribed test method or receive approval for an alternative method before conducting the test.

4. Notification Prior to Testing

The Permittee must notify the Director at least 30 calendar days prior to conducting any tests required by this Permit. The Director may allow a shorter notification period if it would be sufficient to enable EPA or a designated representative to witness the test, or if EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MI tests, or it may be on an individual basis.

5. Loss of Mechanical Integrity

Loss of MI may include any malfunction of the injection well including, but not limited to, a failed MI test, fluids flowing at the surface, wellhead malfunctions, loss of fluids during annulus fill-ups, or a significant change in the annulus or injection pressure during normal operating conditions that may be indicative of a loss of MI. Any well alteration that has the potential to compromise MI will constitute a loss of MI. This includes, but is not limited to, any time the tubing or packer is removed from the well, moved within the well, reset, or replaced.

The Permittee must cease injection immediately upon becoming aware that the well(s) lacks or is suspected of lacking MI. Within 24 hours of the event, the Permittee must notify the Director of the circumstances surrounding the event in accordance with Section I.11(e). The Permittee must also cease injection immediately upon receiving notification from the Director that the well(s) lacks or is suspected of lacking MI and restore MI within the timeframe established by the Director.

The Director may allow plugging of the well(s) pursuant to 40 CFR § 146.10, or require the Permittee to perform additional construction, operation, monitoring, reporting, or corrective action as necessary to prevent the movement of fluid into or between USDWs.

The Permittee must notify the Director at least 30 calendar days prior to conducting well repairs and associated MI demonstration. The Director may allow a shorter notification period if it provides EPA with sufficient time to review and comment on the proposed repair and arrange on-site inspections. The well(s) must remain shut-in until the Permittee receives written approval from the Director to resume injection.

SECTION D. MONITORING, RECORDING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

Monitoring parameters are specified in ATTACHMENT IV. The listed parameters are to be monitored, recorded, and reported at the frequency indicated in ATTACHMENT IV, even when the well is not operating. In the event the well has not injected or is no longer injecting, the monitoring report will reflect that status. Required sampling data must be submitted if the well has injected any time during the reporting period.

Records of monitoring information must include:

(a) the date, exact place, and time of the observation, sampling, or measurements; and

(b) the individual(s) who performed the observation, sampling, or measurements

Records for sampling analysis must include:

(a) the date(s) of analyses and individuals who performed the analyses;

(b) a description of both sampling methodology and the handling of samples;

(c) the analytical technique or method used; and

(d) the results of such analyses.

2. Monitoring Methods

Observations, measurements, and samples taken for the purpose of monitoring must be representative of the monitored activity. Sampling methods used to monitor the characteristics of the injected fluids must comply with analytical methods cited in ATTACHMENT III, or by other methods that have been approved in writing by the Director.

Pressure monitoring (e.g., injection tubing, tubing-casing annulus), injection rate, injected volume, and cumulative injected volume must be monitored and recorded at the wellhead. All parameters must be monitored simultaneously to provide a clear depiction of well operation. For all annuli monitored, annulus pressures must be recorded prior to bleed-off. Annulus pressure applied during internal MI tests should not be included in the monitoring report.

3. Records Retention

The Permittee must retain records of all monitoring information, including the following:

(a) Calibration and maintenance records;

(b) All original strip charts or other recordings for continuous monitoring instrumentation;

(c) Copies of all records required by this Permit;

(d) Records and results of MI tests and any other tests or logs required by the Director;

(e) Records of all data used to complete the application for this Permit; and

(f) Other records related to the construction, operation, and closure of a well.

These records must be retained for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by request of the Director at any time.

The Permittee must retain records of the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures in accordance with ATTACHMENT VI of this Permit. The Permittee must continue to retain the records after the three-year retention period unless the Permittee delivers the records to the Regional Administrator, or an authorized representative, or obtains written approval from the Regional Administrator, or an authorized representative, to discard the records.

4. Submission of Sampling and Monitoring Reports

The Permittee must submit sampling and monitoring reports to the Director at the frequency required in ATTACHMENT III and ATTACHMENT IV in accordance with Section I.11 of this Permit. EPA Form 7520-8 or 7520-11 or their equivalents may be used or adapted to submit the reports along with any additional information required in ATTACHMENT III and ATTACHMENT IV. The Permittee must submit the report to the Director as required in ATTACHMENT III and ATTACHMENT IV. Reporting requirements begin once the permit becomes effective and are required even when injection activity has not begun.

SECTION E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee must notify the Director in writing at least 30 days prior to plugging and abandoning of an injection well. If the Permittee intends on deviating from the previously approved P&A plan, the Director must be notified of the intended deviation no less than 45 days prior to the start of the plugging work. The Director may allow a shorter notification period if it provides EPA with sufficient time to review and comment on the proposed changes.

2. Approved Plugging and Abandonment Plan

The approved P&A plan and required tests are incorporated into this Permit as ATTACHMENT VI. Changes to the approved P&A plan must be submitted using EPA Form 7520-19 at least 45 days prior to plugging, or less if approved by the Director. The Director may determine that a permit modification is needed to implement a proposed change. Changes to the approved P&A plan must not be implemented until after the Permittee has received approval from the Director. Upon approval, the Permittee must comply with such changes, and such changes constitute enforceable requirements of this permit. The Director also may require revision of the approved P&A plan at any time prior to plugging the well.

3. Well Plugging Requirements

(a) Prior to abandonment, the well(s) must be plugged with cement in a manner that isolates the injection zone and will not allow the movement of fluids into or between USDWs. Plugging and abandonment must be conducted in accordance with 40 CFR § 146.10 and follow the procedures outlined in the approved P&A plan incorporated in ATTACHMENT VI. Additional federal, tribal, state, or local laws or regulations may also apply.

(b) Unless converted to a non-UIC well, the well(s) must be plugged and abandoned in accordance with all requirements in this section prior to expiration or termination of this Permit.

4. Plugging and Abandonment Report

Within 60 days after plugging a well, the Permittee must submit a completed EPA Form 7520-19 to the Regional Administrator or an authorized representative. The plugging report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:

(a) a statement that the well was plugged in accordance with the approved P&A plan; or

(b) where actual plugging differed from the approved P&A plan found in ATTACHMENT VI, an updated version of the plan that specifies the differences.

5. Wells Not Actively Injecting

After a cessation of operations of two years, the Permittee must plug and abandon the well in accordance with Section E.2 and ATTACHMENT VI of this Permit unless the Permittee:

(a) Provides written notice to the Regional Administrator or an authorized representative, of the period of temporary abandonment prior to the end of the two-year period;

(b) Describes actions or procedures, satisfactory to the Regional Administrator or an authorized representative, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. This must include an Internal MI demonstration conducted no more than one year prior to the two-year period and may include additional actions or procedures deemed necessary by the Director to protect USDWs. Compliance with the technical requirements applicable to active injection wells must be continuously maintained, unless waived by the Regional Administrator or an authorized representative; and

(c) Receives written notice by the Regional Administrator or an authorized representative to temporarily waive plugging and abandonment requirements.

The above request must be made every two years the well remains temporarily abandoned. The Permittee of a well that has been temporarily abandoned must notify the Director within 30 days after resuming operation of the well.

After a period of ten consecutive years during which there is no injection, the well must be plugged and abandoned in accordance with Section E.1 through E.4 or converted to a non-UIC well in accordance with Section F.2. *Injection Well Conversion*.

SECTION F. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, termination, or 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. Injection Well Conversion

The Permittee must provide a 30-day notice prior to planned well conversion to another type of UIC or non-UIC well. The notification must include the following:

(a) The type of well to which the authorized well will be converted, and

(b) A completed 7520-19 form or its equivalent.

The Permittee must receive prior written approval from the Director to proceed with conversion. After conversion work has been completed, the Permittee must provide to the Director:

(a) Demonstration of Internal MI conducted no more than one year prior to conversion. Additionally, External MI demonstration must be in compliance with permit schedule; and

(b) Documentation that another agency has regulatory authority over the proposed type of well.

The Permittee must convert the well(s) in a manner that will not allow movement of fluids into or between USDWs. The Permittee must also ensure that the conversion meets all applicable federal, tribal, state, and local requirements. The Permittee must continue to meet all permit requirements until written confirmation of permit expiration is received from the Director.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner or operator only if:

(a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d) and requiring submission to the Director of a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittees) to identify the new Permittee and incorporate such other requirements as may be necessary under the SDWA, or

(b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least 30 days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new permittee. If the Director does not notify the Permittee and the proposed new permittee of his or her intent to modify or revoke and reissue, the transfer is effective on the date specified in the written agreement.

Until and unless either of these requirements are met, the Permittee remains liable for all permit compliance and the transferee has no authority to operate or control any well pursuant to this Permit.

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.

SECTION G. 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 will not be affected thereby. Additionally, if a permit modification is required, then only those conditions to be modified will be reopened. All other aspects of the existing permit modification will remain in effect for the duration of the permit.

SECTION H. CONFIDENTIALITY

Any information that the Permittee may claim as Confidential Business Information (CBI) or Proprietary Business Information (PBI) in accordance with 40 CFR part 2 and 40 CFR § 144.5 must be asserted at the time of submission by stamping the words "Confidential Business Information" on each page containing such information. Alleged confidential portions of otherwise non-confidential documents should be clearly identified and include a date or event, if any, after which the information no longer needs to be treated as CBI or PBI.

The Permittee is prohibited from claiming confidentiality for the following information:

(a) the name and address of the Permittee; and

(b) information which deals with the existence, absence, or level of contaminants in drinking water.

All confidentiality claims submitted to EPA are subject to EPA verification in accordance with 40 CFR § 2.208. The Permittee bears the burden of substantiating the claim. Generalized or conclusory statements will be given little or no weight in the determination on the confidentiality of the claimed information.

If no claim is made at the time of submission, EPA will deem the information to be releasable to the public without further notice.

SECTION I. CONDITIONS APPLICABLE TO ALL PERMITS

1. Prohibition on Movement of Fluid Into a USDW

The Permittee must not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized under part 146, the Permittee may be subject to additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to prevent such movement as mandated by the Director.

2. Duty to Comply

The Permittee must comply with all conditions of this Permit and attachments. Any permit noncompliance constitutes a violation of the SDWA 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 as such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to enforcement for compliance, civil penalties, and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. Need to Halt or Reduce Activity Not a Defense

It will 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 must 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 must 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 include 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, 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 and Private Rights; Other Laws

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 applicable federal, tribal, state, or local law or regulations.

8. Duty to Provide Information

The Permittee must furnish to the Director, within the time specified, any information that 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 must also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. Inspection and Entry

The Permittee must 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 purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory and Certification Requirements

All applications, reports, or other information submitted to the Regional Administrator or an authorized representative, must be signed and certified according to 40 CFR § 144.32. This regulation explains the requirements for persons duly authorized to sign documents and provides the required certification statement below that must accompany every submitted report:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

This certification statement is required, unless an EPA approved 7520 form is used.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Section D.10. *Signatory and Certification Requirements* of this Permit and submitted in a manner approved by the Director. All correspondence must reference the well name, well location, and EPA Permit number.

Reports and notifications required by this Permit should follow the Procedures for Submitting Required Reports and Notifications found at: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#contact.

(a) *Sampling and Monitoring Reports.* Sampling and monitoring results must be reported at the intervals specified in ATTACHMENT III and ATTACHMENT IV.

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

(c) *Anticipated noncompliance.* The Permittee must give advance notice to the Director of any planned changes in the permitted facility or activity that may result in noncompliance with Permit requirements.

(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 must be submitted no later than 30 calendar days following each schedule date.

(e) *Twenty-four-hour reporting.* The Permittee must report to the Director any circumstance that may endanger human health or the environment, including:

(i) any monitoring or other information indicating that any contaminant may cause an endangerment to a USDW, including any loss or suspected loss of MI; or

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

Information must 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 (800) 227-8917 and requesting EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report must be provided to the Director within five calendar days of the time the Permittee becomes aware of the circumstances. The written submission must contain a description of the event, the causes of the event, the period of the event (i.e. exact dates and times), and the steps taken or planned to reduce, eliminate, and prevent recurrence. If the noncompliance has not been corrected, the anticipated time to achieve compliance must also be included.

(f) *Other Noncompliance.* The Permittee must report all instances of noncompliance not reported under paragraphs 11(a), 11(d), or 11(e) of this section at the time that monitoring reports are submitted. The reports must contain the information listed in paragraph 11(e) of this section.

(g) *Other information.* Where the Permittee becomes aware of a failure to submit any relevant facts in a permit application, submitted incorrect information in a permit application, or submitted incorrect information in any report to the Director, the Permittee must submit such facts and corrections to the Director within 30 days of discovery of failure.

(h) *Oil Spill and Chemical Release Reporting.* The Permittee must 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 or NRC@uscg.mil.

SECTION J. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee must demonstrate and maintain financial responsibility (FR) and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

(a) The well(s) has been plugged and abandoned in accordance with the approved P&A plan in ATTACHMENT VI, and the Permittee has submitted a P&A report according to Section E.4; or

(b) The well(s) has been converted in compliance with the requirements of Section F.2; or

(c) The Permittee has received notice from the Director that the Permit has been successfully transferred to a new owner or operator, which includes financial responsibility demonstration.

No substitution of a demonstration of financial responsibility will become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable.

When a financial test is used as the financial mechanism, this coverage must be updated on an annual basis.

2. Types of Adequate Financial Responsibility.

The Permittee must show evidence of financial responsibility to the Director through the submission of a surety bond, letter of credit, trust fund, financial test, or other adequate assurance acceptable to the Director. For more information regarding adequate types of financial assurance, contact your EPA Regional Office.

3. Determining How Much Coverage is Needed

The owner or operator must revise the plugging and abandonment cost estimate whenever a change in the P&A plan(s) increases the cost of plugging and abandonment and provide a revised demonstration of financial responsibility.

Additionally, the Regional Administrator or an authorized representative, 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(s) to adjust for inflation and provide a revised demonstration of financial responsibility.

4. Bankruptcy and/or Insolvency of the Permittee

The Permittee must 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 10 business days after commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if the guarantor is named as debtor, as required under the terms of the guarantee. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

5. Bankruptcy, Insolvency, Suspension, or Loss of Authority of an Issuing Financial Institution

In the event of insolvency or bankruptcy of the trustee or issuing institution of the financial mechanism, the suspension or revocation of the authority of the trustee institution to act as trustee, or the issuing institution losing authority to issue such an instrument, the Permittee must notify the Director within 10 business days of receiving notice of such event by certified mail. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

An owner or operator who obtains an instrument type such as letter of credit, surety bond, or insurance policy will be deemed to be without the required FR or liability coverage in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution. The owner or operator must establish other FR or liability coverage acceptable to the Director within 60 calendar days after such an event. See 40 CFR §§ 144.28(d)(6) & 144.64(b).

ATTACHMENT I - WELL CONSTRUCTION REQUIREMENTS

1. Construction Requirements

The approved plan includes the minimum requirements listed below. Should a Permittee need to modify the approved plan, the following standards, at a minimum, must be satisfied in any plan submitted in accordance with Section A. *Well Construction Requirements*.

Applicable to Newly Constructed Well(s)

- Casing and cement used in the construction of the well must be designed to perform as expected over the life expectancy of the well, accounting for natural and applied pressures and chemical conditions.
- Well(s) must be completed with at least two cemented casing strings set within a drilled hole, in addition to any conductor pipe.
- Casing strings must be cemented as follows:
  - o Surface casing is cemented from the casing shoe to the surface, and
  - o All USDWs must be isolated by placing cement between the outermost casing and the well bore.
- When drilling the surface hole, unless waived by the Director, air or mud made with water containing no additives and no more than 3,000 mg/L TDS must be used. At no time will the Permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR § 144.12.

Applicable to all wells:

- The well must be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the top of the open hole.

Currently, the well is constructed as:

- 7” LTD 17 lbs/ft surface casing set in an 8-3/4” hole to a depth of 664 feet (below ground level) and cemented with 260 sacks Class G Cement to the surface.
- 4-1/2” J-55, 10.5 lbs/ft long string casing set in an 6-1/4” hole to a depth of 3,418 feet cemented with 125 sacks Class G Cement.
- Open 3-7/8” hole between 3,418 feet to 3,499 feet
- 2-3/8” J-55, 4.7 lbs/ft tubing set at 3,366
- Packer set at 3,373 feet depth

2. Required Monitoring Devices

The following sampling and monitoring devices are required:

- A pressure actuated device attached to the injection flow line set to prevent MAIP from being reached at the wellhead;
- At least one female pipe fittings capable for attachment to a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP. The fittings must be isolated by shut-off valves and conveniently accessible near the wellhead. Fittings must be present at these locations:
- on the injection tubing string(s);
- on the tubing-casing annulus (TCA); and
- on any other annulus space required to be monitored in the Permit;
- A sampling port such that samples can be collected at a location that ensures they are representative of the

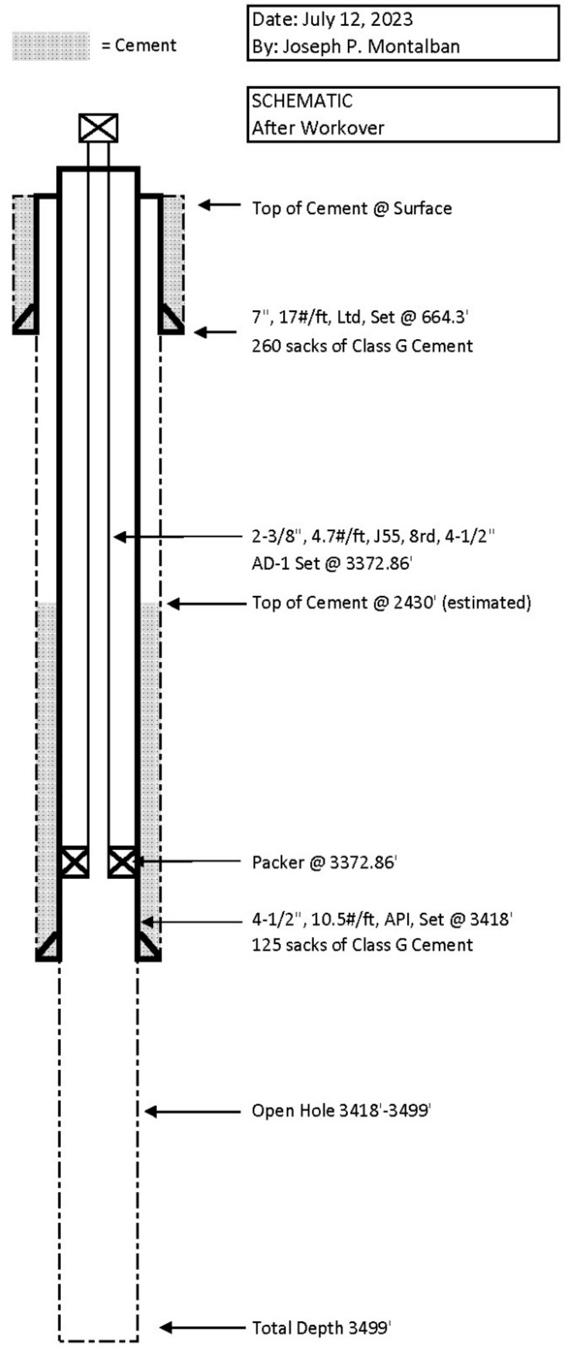
injected fluid; and

- A flow meter capable of recording instantaneous flow rate and volume attached to the injection line.

3. Well Schematic

Well: Jody Field #34-2
API#: 25-073-21838
County: Pondera
Field: Wildcat
Location: SESESW-Section 34-T29N-R6W (2310' FSL -990' FWL)

Formation	Top	Btm	Lithology	Status
Two Medicine	0	484	Sandstone	USDW
Eagle/Virgelle	484	664	Sandstone	USDW
Colorado Shale	664	1780	Shale	Confining zone
Blackleaf	1780	2028	Fine-grained Sandstone with units of Shale	Confining zone
1st Bow Island	2028	2534	Fine-grained Sandstone with units of Shale	Confining zone
Dakota	2534	2573	Sandstone	USDW
Kootenai	2573	3096	Sandstone	USDW
Sunburst	3096	3203	Sandstone	USDW
Swift	3203	3330	Fine-grained Sandstone with units of Shale	Confining zone
Rierdon	3330	3404	Marlstone	Confining zone
Sawtooth	3404	3418	Siltstone	Confining zone
Madison	3418		Dolomite	Exempted



ATTACHMENT II - OPERATING REQUIREMENTS

1. *Area of Review*

The AOR for this Permit is within a fixed 0.25-mile radius about the injection well.

2. *Injection Zone*

The formation(s) and/or stratigraphic unit(s) listed in the table below, comprise the allowable injection zone(s):

Injection Zone Table

Formation Name or Stratigraphic Unit	Top (ft.)	Bottom (ft.)	Exemption Status
Madison Formation	3,418	~3,700*	Montana Board of Oil and Gas Conservation (MBOGC) submitted an Aquifer Exemption (AE) for the Madison Formation for the Jody Field 34-2 well to the EPA. On March 15, 2010, the EPA reviewed and concurred on this aquifer exemption for the Madison Formation within a one-quarter (1/4) mile radius from the wellbore between the depths of 3,418 to 3,451 feet, in accordance with 40 CFR §§144.7 and 146.4 of the Safe Drinking Water Act.

*An aquifer exemption expansion is proposed for the Madison formation to a depth of 3,451 to approximately 3,700 feet.

The well is currently drilled to a total depth of 3,499 feet. A major modification will be required to deepen the well to access the deeper portion of the Madison Formation.

3. *Maximum Allowable Injection Pressure (MAIP)*

The parameters below are the values used to calculate the initial authorized MAIP issued with this Permit. These parameters may be updated throughout the life of the well, pursuant to the conditions and formula at Section B.4. of this Permit. The recalculated MAIP becomes effective and enforceable upon the written correspondence from the Director. The Director may also determine that a permit modification is needed to implement the change.

The table below provides the initial values used to calculate the initial MAIP:

Fracture Gradient	Specific Gravity	SG Fluctuation Factor	Injection Zone Top Depth (ft)	Friction Loss (psi)	Authorized MAIP (psi)
0.634	1.004	0.05	3,418	81	688

Fracture Gradient must be determined by conducting a valid step rate test, reviewed, and approved by the Director. Alternative methods to determine a representative fracture gradient may be used, if approved by the Director.

Specific Gravity must be derived from the results of the analytical sample required in ATTACHMENT III. The specific gravity value used to calculate the initial authorized MAIP was estimated. Prior to authorization to inject, the Permittee must provide a measured specific gravity value of the injectate.

Depth is the true vertical depth to the top of the open hole.

4. Tubing-Casing Annulus Pressure

The TCA valve shall remain closed during normal operations and the TCA pressure shall be less than 100 psi.

5. Maximum Cumulative Injection Volume Limitation

The maximum total volume permitted to be injected during the life of the Class V well is 7,156,173 bbls, which is based on a calculation that accounts for the volume previously injected into the well.

6. Injection Fluid Limitation

Injected fluids are limited to fluids associated with oil and natural gas production and industrial wastewater from Montana Renewable generated from the pretreatment of renewable feedstocks. The renewable feedstocks may include, but are not limited to, vegetable oils (such as soybean oil and canola oil), animal fats (such as beef tallow, choice white grease, and poultry fat) distiller's corn oil, and used cooking oil. The Permittee shall not inject any hazardous substances, as defined in 40 CFR 261, at any time during the operation of the facility.

ATTACHMENT III – SAMPLING REQUIREMENTS

Sampling requirements, units for reporting, permit limitations (if applicable), sampling methods, and reporting frequencies are listed below. Sampling analytical methods must comply with those found in 40 CFR §136.3, Table 1 and APPENDIX II of 40 CFR 261. Methods specified below are also acceptable. Alternative analytical methods may be used if pre-approved by the Director.

Results of the sampling requirements must be provided:

- Prior to receiving initial authorization to commence injection.
- Prior to introduction of a new source into the well. The Director must be provided a notification that includes results of sampling analysis, a description of the fluid, and a description of the process that generated the fluid as described in Section B.6 of this Permit. Analysis of additional constituents may be requested on a case-by-case basis.
- At the sampling reporting frequency described in the table below.
- At the request of the Director.

Sampling Requirement	MAIP Revision Trigger	Minimum Recording Frequency	Minimum Reporting Frequency
Total Dissolved Solids (TDS)	--	Quarterly	Quarterly
pH	--	Quarterly	Quarterly
Specific Gravity	1.054*	Quarterly	Quarterly
Specific Conductance/Conductivity	--	Quarterly	Quarterly

*The specific gravity of the fluid provided with the application was estimated. A specific gravity greater than the MAIP Revision Trigger may require a MAIP recalculation (see Section B.4 of the Permit). The specific gravity MAIP Revision Trigger value will be revised after a sample analyzed for specific gravity is provided.

ATTACHMENT IV – MONITORING AND REPORTING REQUIREMENTS

Monitoring requirements, units for reporting, permit limitations (if applicable), and monitoring, recording, and reporting frequencies are listed below.

- All parameters must be observed simultaneously to provide a clear depiction of well operation.
- Tubing-casing annulus pressure must be recorded prior to bleed-off.
- Annulus pressure applied during standard annulus pressure tests related to MI tests should not be included in the annual monitoring report.

Monitoring and Reporting Requirement	Maximum Permit Limit	Report Parameter	Monitor Frequency	Minimum Recording Frequency	Minimum Reporting Frequency
Surface Inj Pressure (psi)	688	Min/Average/Max	Continuous	Monthly	Quarterly
TCA Annulus Pressure (psi)	100	Min/Average/Max	Continuous	Monthly	Quarterly
Injection Rate (bbl/day)	NA	Min/Average/Max	Continuous	Monthly	Quarterly
Cumulative Volume (bbl) (since Class V authorization)	7,156,173*	Monthly Total	Continuous	Monthly	Quarterly
Injection Volume (bbl)	NA	Monthly Total	Continuous	Monthly	Quarterly
Bradenhead Annulus Pressure (psi)	NA	Min/Average/Max	Continuous	Monthly	Quarterly
Field 14-34 Wellhead Pressure (psi)	NA	Min/Average/Max	Monthly	Monthly	Quarterly
The Permittee must provide a listing of the sources of injected fluids. Copies of all monthly records on injected fluids, and any major changes in characteristics or sources of injected fluid shall be included in the Quarterly Report.					Quarterly
Document the review performed to determine if additional wells exist within the area of review that have not previously been identified. For those wells that penetrate the confining zone, a well construction diagram, cement records and cement bond log are also required.					Quarterly

*This value represents the volume limitation permissible as a Class V UIC well. Past injection volumes have been accounted for in this calculation.

Quarterly Reports must cover the period from January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Quarterly Reports must be submitted by the fifteenth day of the month following the end of the data collection period. EPA Form 7520-8 may be used or adapted to submit the Quarterly Report. The monitoring requirements specified in this Permit are mandatory even if an EPA form does not include all information.

ATTACHMENT V – LOGGING AND TESTING REQUIREMENTS

Well logs and tests must be performed according to 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. Well logging and testing procedures must be submitted to the Director prior to conducting any well log or test.

Well logs and test results must be submitted to the Director within 60 calendar days of the logging or testing activity completion and must include a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, an interpretative report must be prepared by a knowledgeable log analyst that also includes detailed analysis of: (1) USDWs and adjacent confining zone(s) and (2) the injection zone and adjacent confining zone(s).

Test/Log Requirement	Date Due
MIT1-Standard Annulus Pressure	Prior to receiving authorization to inject. SAP will be conducted no less than every 5 years after the last successful internal (Part I) MI demonstration.
MIT2-Cement Bond Log	Prior to receiving authorization to inject.
MIT2-Noise or Temperature Log	Either a noise log or a temperature log must be conducted 9-12 months after injection begins and subsequent tests must be conducted no less than every 5 years after the last successful external (Part II) MI demonstration.
Noise Log*	Prior to receiving authorization to inject.
Pressure Fall Off Test**	The first test must be conducted 9-12 months after injection begins and subsequent tests must be conducted annually thereafter, not to exceed 12 months of the previous test.

*A noise log must be performed to assess the presence of fluid movement between the exposed upper USDWs (Dakota, Kootenai, and Sunburst) and adjacent formations. Based on the calculated top of cement, the existing cement does not appear to prevent movement of fluids between the upper USDWs and the confining layers. The noise log must be conducted between the top of cement behind the 4.5-inch casing and the base of the 7-inch surface casing. If the noise log indicates potential fluid movement, there may be additional requirements to protect USDWs.

** The Permittee is required to prepare a plan for running the falloff test. *EPA Region 6 UIC Pressure Falloff Testing Guideline* should be used by the Permittee when developing a site-specific plan. This document can be found at: https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf.

The test plan shall be submitted to EPA for review at least 30 days prior to conducting the annual pressure falloff test. Subsequent test plan is required only if it is not identical to the previous year's plan. It is important that the initial and subsequent tests follow the same or similar test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made.

The report shall also compare the test results with previous years test data, unless it is the first test performed at that well. A falloff test that fails to adhere to these requirements may be subject to retest.

The Permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall be prepared by a knowledgeable analyst, comparing the test results with previous years test data, unless it is the first test performed for the well.

ATTACHMENT VI - PLUGGING AND ABANDONMENT REQUIREMENTS

The approved plan is provided in this attachment and is designed to prevent vertical fluid movement into and between USDWs. Should the Permittee need to modify the approved plan, the following standards, at a minimum, must be satisfied in any submission in accordance with Section E. *Plugging and Abandonment*.

- Internal MI demonstration must be conducted no more than one year prior to plugging. If required, External MI demonstration must be in compliance with permit schedule.
    - Prior to plugging a well, MI must be established unless the P&A plan will address a loss of MI.
- Injection tubing must be removed.
- Cement plugs must have sufficient compressive strength to maintain adequate plugging effectiveness.
- The well to be abandoned must 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, prior to the placement of the cement plug(s).
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- All USDWs must be isolated by placing cement between the outermost casing and the well bore.
- A minimum 50-foot surface plug is required inside and, if necessary, outside of the surface casing, to seal pathways for fluid migration into the subsurface.

4 1/2” casing will be cut at approximately 2,015’ and removed.

At a minimum, the following plugs are required.

Plug #1: Set CICR at approximately 3,390’, 50–100’ above the injection interval. Pump cement to provide coverage from approximately 3,390’ to 3,499’. Sting out of retainer and place Class G cement on top of the CICR from approximately 3,140’ to 3,390’.

Plug #2: Establish circulation with gelled water and balance cement plug from approximately 2,484’ to 2,634’ (covering the Dakota Sandstone and Kootenai Formation tops). Tag out the plug at 2,484’.

Plug #3: Establish circulation with gelled water and balance cement plug from approximately 1,965’ to 2,065’ (sealing off the remaining casing stub before isolating other zones uphole). Tag out the plug at 1,965’.

Plug #4: Set a cement plug from approximately 1,735’ to 1,965’. Tag out the plug at 1,735’.

Plug #5: Establish circulation with gelled water and balance cement plug across the surface casing shoe from approximately 615’ to 715’ (isolating the Two Medicine and Eagle/Virgelle USDWs from the underlying Colorado Shale confining zone and covering the surface casing shoe). Tag out the plug at 615’.

Plug #6: Spot cement cap through tubing from surface to approximately 100’. Dig out well 6’ below surface, cut and cap well at 4’ below ground level.

Remove wellhead and working pit and install P&A marker.

Plugging Abandonment Well Bore Schematic

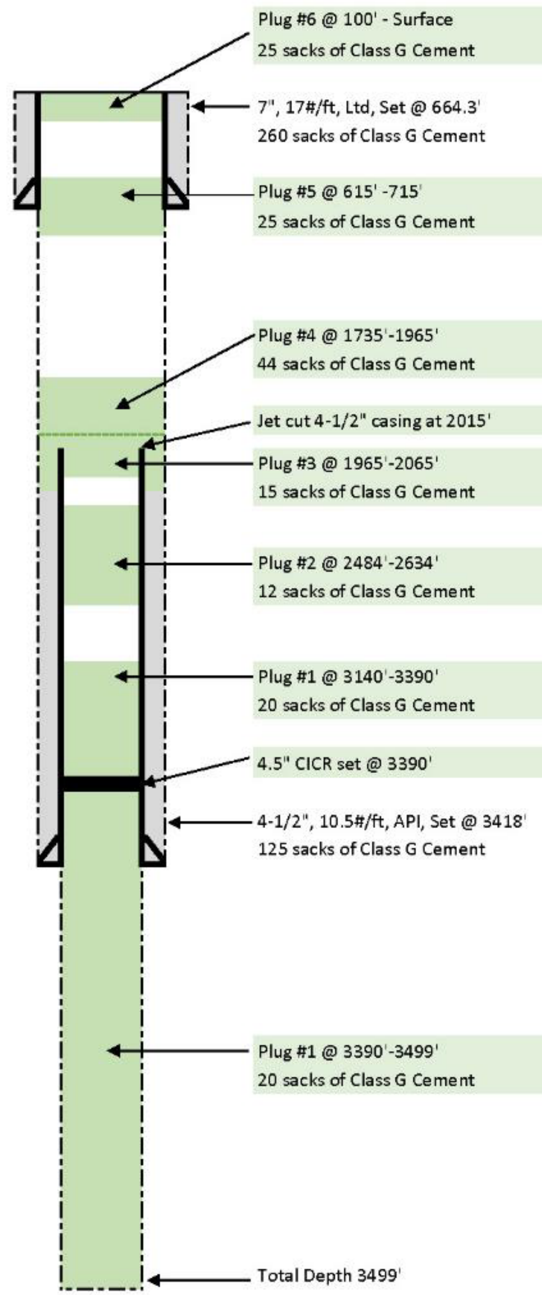
Well: Jody Field #34-2
API#: 25-073-21838
County: Pondera
Field: Wildcat
Location: SESESW-Section 34-T29N-R6W (330' FSL -2310' FWL)

Date: July 12, 2023
By: Joseph P. Montalban

= Exisiting Cement
= P&A Cement

P&A SCHEMATIC

Formation	Top KB	Btm KB	Lithology	Status
Two Medicine	0	484	Sandstone	USDW
Eagle/Virgelle	484	664	Sandstone	USDW
Colorado Shale	664	1780	Shale	Confining zone
Blackleaf	1780	2028	Fine-grained Sandstone with units of Shale	Confining zone
1st Bow Island	2028	2534	Fine-grained Sandstone with units of Shale	Confining zone
Dakota	2534	2573	Sandstone	USDW
Kootenai	2573	3096	Sandstone	USDW
Sunburst	3096	3203	Sandstone	USDW
Swift	3203	3330	Fine-grained Sandstone with units of Shale	Confining zone
Rierdon	3330	3404	Marlstone	Confining zone
Sawtooth	3404	3418	Siltstone	Confining zone
Madison	3418		Dolomite	Exempted



ATTACHMENT VII - CORRECTIVE ACTION PLAN

No corrective action is required at this time as EPA's evaluation did not identify migration pathways within the area of review.