U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

CLASS I NONHAZARDOUS

PERMIT NUMBER MI-133-1I-0002

CARGILL INCORPORATED

Hersey, Michigan

TABLE OF CONTENTS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

U.S. ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS I NON-HAZARDOUS

Permit Number: MI-133-1I-0002

Facility Name: Thomas 1-26

Pursuant to the Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR), Parts 124, 144, 146, and 147,

Cargill Incorporated of Hersey, Michigan

is hereby authorized to continue operation of an existing Class I non-hazardous injection well located in Michigan, Osceola County, T17N, R9W, Section 26, NW Quarter Section, for injection into the Dundee Limestone, Reed City Anhydrite, and Reed City Dolomite at depths between 3830 feet and 4085 feet upon the express condition that the permittee meet the restrictions set forth herein. The injection of any hazardous fluid as specified in 40 CFR Part 261 is prohibited.

All references to Title 40 of the Code of Federal Regulations (40 CFR) are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit: A, B, C, D, E, F, and G.

This permit shall become effective on _____, and shall remain in full force and effect during the life of the permit, unless this permit is revoked, terminated, modified, or reissued pursuant to 40 CFR §§144.39, 144.40 or 144.41.

This permit and authorization to inject shall expire at midnight on_____, unless terminated prior to the expiration date.

Signed and Dated: _____

DRAFT

_____
Tera L. Fong
Division Director,
Water Division

PART I
GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs). The objective of this permit is to prevent the introduction of contaminants into USDWs if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance, with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, or any other common or statutory law other than Part C of the SDWA. 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 State or local law or regulations. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable regulations.

B. PERMIT ACTIONS

1. Modification, Revocation, Reissuance, and Termination - The Director of the Water Division of the United States Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§ 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or 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 permit condition.

2. Transfer of Permits - This permit is not transferable to any person except in accordance with 40 CFR §144.38.

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.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and Section 144.5, any information submitted to the EPA 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, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

1. The name and address of the permittee; and

2. Information which deals with the existence, absence or level of contaminants in drinking water.

E. DUTIES AND REQUIREMENTS

1. Duty to Comply - The permittee shall comply with all applicable SDWA regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 C.F.R. §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. Penalties for Violations of Permit Conditions - Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Continuation of Expiring Permits

(a) Duty to Reapply - If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 180 calendar days before this permit expires.

(b) Permit Extensions - The conditions of an expired permit may continue in force in accordance with 5 U.S.C. 558(c) and 40 CFR §144.37.

(c) Effect - Permits continued under 5 U.S.C. 558(c) and 40 CFR §144.37 remain fully effective and enforceable.

(d) Enforcement - When the permittee is not in compliance with the conditions of the expiring or expired permit, the Director may choose to do any or all of the following:

(1) Initiate enforcement action based upon the permit that has been continued;

(2) Issue a notice of intent to deny the new permit, in which case the owner or operator would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operation without a permit;

(3) Issue a new permit under 40 CFR Part 124 with appropriate conditions; or

(4) Take other actions authorized by the UIC regulations.

(e) State Continuation - An EPA-issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement responsibility under the SDWA. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit. Furthermore, if the State does not continue the EPA permit upon obtaining primary enforcement responsibility, the permittee must obtain a new State permit or be authorized to inject by State rule. Failure to do so while continuing to operate the well constitutes unauthorized injection and is a violation subject to enforcement action.

4. Need to Halt or Reduce Activity Not a Defense - It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. Duty to Mitigate - The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. 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 that 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 or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. Duty to Provide Information - The permittee shall furnish to the Director, within a 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 also shall furnish to the Director, upon request, copies of records required to be kept by this permit.

8. 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, at reasonable times, upon the permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that are 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 facilities, equipment or operations regulated or required under this permit.

9. Records

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records, all records of monitoring instrumentation, and copies of all reports required by this permit for a period of at least five years from the date of the sample, measurement, or report, unless these materials are submitted to the Director as part of reporting requirements under this permit.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information submitted under 40 CFR §§144.27, 144.28, and 144.31 for a period of at least five years from the date the permit application was signed.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until three years after the completion of plugging and abandonment of this injection well.

(d) The retention period specified in Part I(E)(9)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Part I(E)(9)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(1) The date, exact place, and time of sampling or measurements;

(2) The name(s) of individual(s) who performed the sampling or measurements;

(3) A precise description of both sampling methodology and the handling of samples;

(4) The date(s) analyses were performed;

(5) The name(s) of individual(s) who performed the analyses;

(6) The analytical techniques or methods used; and

(7) The results of such analyses.

10. Monitoring - Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The permittee shall use the methods described in "Test Methods for the Evaluation of Solid Waste, Physical/Chemical Methods" (available from Solid Waste Information, EPA, 26 W. St. Claire St., Cincinnati, Ohio 45268 and https://www.epa.gov/hw-sw846), or equivalent methods approved by the Director, to take representative samples. Monitoring results shall be reported at the intervals contained in Part II(D)(1) through (3) and Part III(A) of this permit.

(a) Monitoring of the nature of injected fluids shall comply with applicable analytical methods cited and described in Table I of 40 CFR §136.3 or in certain circumstances by other methods that have been approved by the Director.

(b) Sampling and analysis shall comply with the specifications of the Waste Analysis Plan required in Part II(C)(3) of this permit.

11. Signatory Requirements - All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR §144.32.

12. Reporting Requirements

(a) Planned Changes - The permittee shall give written notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted facility.

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

(c) 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 by the permittee no later than 30 calendar days following each schedule date.

(d) Twenty-four Hour Reporting

(1) The permittee shall report to the Director any permit noncompliance that may endanger human health or the environment. See, e.g., Part I(G)(5) of this permit. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such reports shall include, but not be limited to the following information:

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

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

(iii) Any failure to maintain mechanical integrity.

(2) A written submission shall also be provided within five working 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 steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

(e) Other Noncompliance - The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part I(E)(12)(d)(2) of this permit.

(f) Other Information - When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts or corrected information within 10 calendar days.

(g) Report on Permit Review - Within 30 calendar days of receipt of this permit, the permittee shall certify to the Director that he or she has read and is personally familiar with all terms and conditions of this permit.

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment - The permittee shall notify the Director at least 60 calendar days before conversion or abandonment of the well. At the discretion of the Director, a shorter notice period may be allowed.

2. Plugging and Abandonment - The permittee must receive the approval of the Director before plugging the well and shall plug and abandon the well consistent with 40 CFR §144.52(a)(6) and 146.10, as provided for in the Plugging and Abandonment Plan contained in Part III(B) of this permit. Within 60 calendar days after plugging a well, the permittee shall submit a Plugging and Abandonment report to the Director. The report shall be certified as accurate by the permittee and by the person who performed the plugging operation (if other than the permittee), and shall consist of either:

(a) A statement that the well was plugged in accordance with the Plugging and Abandonment Plan previously approved by the Director; or

(b) If the actual plugging differed from the approved plan, a statement defining the actual plugging and explaining why the Director should approve such deviation. If the Director determines that a deviation from a previously approved plan may endanger underground sources of drinking water, the permittee shall replug the well as required by the Director.

3. Temporary Abandonment -If the permittee ceases injection into the well for 24 consecutive months, the well is considered to be in temporary abandoned status, and the permittee shall plug and abandon the well in accordance with the approved plan and 40 CFR §144.52 (a)(6), or make another demonstration of non-endangerment (e.g., a standard annulus pressure test). During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity. Demonstrations of non-endangerment/testing will be due every two years from the last successful test (unless the permit requires more frequent demonstrations of mechanical integrity). If the well loses mechanical integrity prior to the next test due date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

4. Revision of Plugging and Abandonment Plan - If the permittee finds it necessary to change a Plugging and Abandonment Plan, a revised plan shall be submitted to the Director for approval at the time of the next monthly report.

5. Standards for Well Closure - Prior to plugging and abandoning the well:

(a) The permittee shall observe and record the pressure decay for a time specified by the Director and shall report this information to the Director.

(b) The permittee shall conduct appropriate mechanical integrity testing to ensure the integrity of that portion of the long string casing and cement by

(1) Pressure tests with liquid;

(2) Noise, temperature, pipe evaluation, or cement bond logs; or

(3) Any other test required by the Director.

(c) Prior to well closure, the well shall be flushed with a buffer fluid.

G. MECHANICAL INTEGRITY

1. Standards - The injection well must have and maintain mechanical integrity consistent with 40 CFR §146.8(a)(1) and (2). Mechanical integrity demonstrations must be witnessed by an authorized representative of the Director. Mechanical integrity testing also may be conducted without an EPA authorized representative when it is not possible for the UIC Section to resolve scheduling conflicts with both EPA contract inspectors and the regional technical staff. The permittee is required to perform tests using the procedures described in Part III(G) of this permit.

2. Periodic Mechanical Integrity Testing - The permittee shall conduct the mechanical integrity testing as follows:

(a) Long string casing, injection tubing and annular seal shall be tested by means of an approved pressure test in accordance with 40 CFR §146.8(b)(2). This test shall be performed at least once every twelfth month beginning with the date of the last approved demonstration and whenever there has been a well workover in which tubing is removed from the well, the packer is reset, or when loss of mechanical integrity becomes suspected during operation;

(b) An approved temperature, noise, oxygen activation, or other approved log shall be run upon completion of this well and at least once every 60 months from the date of the last approved demonstration to test for movement of fluid along the bore hole. The Director may require such tests whenever the well is worked over. The permittee must use the logging procedures found in Part III(G) of the permit for the purpose of meeting this requirement;

(c) The permittee may request the Director to use any other test approved by the Director in accordance with the procedures in §146.8(d).

3. Prior Notice and Reporting - The permittee shall notify the Director of his or her intent to demonstrate mechanical integrity at least 30 calendar days prior to such demonstration. At the discretion of the Director a shorter time period may be allowed. Reports of mechanical integrity demonstrations that include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report the results of a mechanical integrity demonstration within 45 calendar days after completion thereof.

4. Gauges - The permittee shall calibrate all gauges used in mechanical integrity demonstrations to an accuracy of not less than one-half percent of full scale, prior to each required test of mechanical integrity. A copy of the calibration certificate shall be submitted to the Director or his or her representative at the time of demonstration and every time the gauge is calibrated. The gauge shall be marked in no greater than five psi increments.

5. Loss of Mechanical Integrity - If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR §146.8(a)(1) and (2) is suspected during operation, the permittee shall halt the operation immediately and follow the reporting requirements as directed in Part I(E)(12) of this permit. The permittee shall not resume operation until mechanical integrity is demonstrated and the Director gives approval to recommence injection.

6. Mechanical Integrity Testing on Request of the Director - The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

H. FINANCIAL RESPONSIBILITY

1. Financial Responsibility - The permittee shall maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner consistent with 40 CFR § 144.52(a)(7). The approved financial assurance mechanism is found in the administrative record for this permit and Part III(C) of this permit.

(a) The permittee must maintain a written cost estimate, in current dollars, for the Plugging and Abandonment Plan as specified in 40 CFR §146.10. The plugging and abandonment cost estimate at any point in the life of the facility operation must equal the maximum cost of plugging and abandonment at that time.

(b) The permittee must adjust the cost estimate of plugging and abandonment for inflation within 30 calendar days after each anniversary of the first estimate. The permittee must revise the plugging and abandonment cost estimate whenever a change in the Plugging and Abandonment Plan increases the cost of plugging and abandonment. The inflation factor is the result of dividing the latest published annual Oil and Gas Field Equipment Cost Index by the index for the previous

year. An up-to-date independent cost estimate also may be used to establish the current plugging and abandonment cost.

(c) If the revised plugging and abandonment estimate exceeds the current amount of the financial assurance mechanism, the permittee shall submit a revised mechanism to cover the increased cost within 30 calendar days after the revision specified in Part I(H)(1)(b) and (c) of this permit.

(d) The permittee must keep on file at the facility a copy of the latest plugging and abandonment cost estimate prepared in accordance with 40 CFR §144.52(a)(7), during the operating life of the facility.

2. Insolvency - The permittee must notify the Director within 10 business days of any of the following events:

(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.

3. Notification - 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 the commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if he or she is named as debtor, as required under the terms of the guarantee.

4. Establishing Other Coverage - The owner or operator must establish other financial assurance or liability coverage acceptable to the Director, within 60 calendar days of the occurrence of the events in Part I(H)(2) or (H)(3) of this permit.

I. CORRECTIVE ACTION

1. Compliance - The permittee shall comply with 40 CFR §§ 144.55 and 146.7.

2. Corrective Action Plan - The permittee shall file a Corrective Action Plan for approval by the Director within 30 days of a written determination by the Director that improperly plugged, completed, or abandoned wells, or wells for which plugging or completion information is unavailable, are present in the area of review and penetrate the confining zone of the permitted well, as defined in the administrative record for this permit.

3. Prohibition of Movement of Fluids into USDWs Should upward migration of fluids through the confining zone of this permitted well be discovered within the two-mile area of review due to injection activities at this facility, and should this migration of fluids cause the introduction of any contaminant into a USDW pursuant to 40 CFR §144.12, the permittee shall immediately cease injection into this well until the situation has been corrected and reauthorization to inject has been given by the Director.

PART II
WELL-SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Siting – The injection well shall inject only into the formation at the depths listed on the cover page of this permit. At no time shall injection occur into a formation which is or is above the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

2. Casing and Cementing – Notwithstanding any other provisions of this permit, the permittee shall case and cement the well in such a manner so as to prevent the movement of fluids into or between USDWs for the expected life of the well. The casing and cement used in the construction of this well are shown in Part III(E) of this permit and in the administrative record for this permit. Any change shall be submitted for approval by the Director before installation.

3. Tubing and Packer Specifications – The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone. The tubing and packer used in the well are represented in engineering drawings contained in Part III(E) of this permit. Any changes shall be submitted by the permittee for the approval of the Director before installation.

4. Wellhead Specification – The permittee shall install and maintain a female coupling and valve on the wellhead, to be used for independent injection pressure readings. Further, the permittee shall install a sampling port for waste sampling consistent with the permittee's waste sampling procedures, if applicable.

B. OPERATIONS

1. Injection Pressure Limitation - Except during stimulation, the permittee shall not cause or permit the injection pressure at the wellhead to exceed the maximum limitation that is specified in Part III(A) of this permit. In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.

2. Additional Injection Limitation - No waste streams other than those identified in Part III(F) of this permit shall be injected. Every twelfth month the permittee shall submit a certified statement attesting to compliance with this requirement.

3. Annulus Fluid and Pressure - The permittee shall fill the annulus between the tubing and the long string casing with a fluid approved by the Director and identified in the administrative record of this permit. Any change in the annulus fluid, except during workovers or times of annulus maintenance, shall be submitted by the permittee for the approval of the Director before replacement. Except during workovers, the permittee shall maintain a positive pressure on the annulus as specified in Part III(A) of this permit.

4. Annulus/Tubing Pressure Differential - Except during workovers or times of annulus maintenance, the permittee shall maintain, over the entire length of the tubing, a pressure differential between the tubing and annulus as specified in Part III(A) of this permit.

5. Automatic Warning and Manual Shut-off System - The permittee shall continuously operate and maintain an automatic warning and manual shut-off system to stop injection within 15 minutes of any of the following situations:

(a) Pressure changes in the annulus or annulus/tubing differential signifying or identifying possible deficiencies in mechanical integrity; or

(b) Injection pressure, annulus pressure, or annulus/tubing differential pressure reaches the pressure limits as specified in Part III(A) of this permit.

(c) A trained operator must be on site and within perceptible distance of the alarm at all times when the well is operating. The permittee must test the automatic warning and shut-off system at least every twelfth month. This test must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative.

6. Precautions to Prevent Well Blowouts

(a) The permittee shall maintain on the well at all times a pressure that will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that can resist the pressure differential. A blowout preventer must be kept in proper operational status during workovers.

(b) In cases where the injected wastes have the potential to react with the injection formation to generate gases, the permittee shall follow the procedures below to assure that a backflow or blowout does not occur:

1) Limit the temperature and pH of the injected waste prior to a workover; and
2) Develop procedures necessary to assure that pressure imbalances do not occur.

C. TESTING AND MONITORING

1. Sampling Point - The injection fluid samples shall be taken at the sampling location as specified in Part III(A) of this permit.

2. Continuous Monitoring Devices - The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, and the pressure on the annulus between the tubing and the long string of casing. The monitoring results shall be submitted to the Director as specified in Part II(D) of this permit. The permittee shall maintain for EPA's inspection at the facility an appropriately-scaled record of these monitoring results as well as original copies of any digitally recorded information pertaining to these operations.

3. Waste Analysis Plan - The permittee shall comply with the written Waste Analysis Plan which describes the procedures used to monitor the nature of injected fluids and the procedures which will be carried out to comply with Part (I)(E)(10) of permit. The plan is part of the Administrative Record for this permit. A copy of the approved plan shall also be kept at the facility.

4. Ambient Monitoring - The permittee shall monitor the pressure buildup in the injection zone initially upon completion of the well, and at least once every twelfth month thereafter, including at a minimum, a shut-down of the well for a time sufficient to conduct a valid observation of the pressure fall-off curve. From this observation, the permittee shall submit a report including at least a calculation of pressure build-up in the injection zone, injection zone transmissivity, and wellbore skin factor. If the permittee chooses, the ambient monitoring may be performed on only one of the two wells at the facility during each twelfth month monitor event. In this case, the permittee shall alternate the twelve-month testing between the two wells on site.

D. REPORTING REQUIREMENTS

The permittee shall submit all required reports to the Director at:

U.S Environmental Protection Agency
Region 5
77 West Jackson Boulevard
Chicago, Illinois 60604-3590
ATTN: Permits Branch (WP-16J)

1. Monthly Reports - The permittee shall submit monthly reports of the following information no later than the end of the month following the reporting period:

(a) A tabulation of maximum injection pressure and minimum differential between simultaneous measurements of injection pressure and annulus pressure for each day of the month;

(b) Appropriately scaled graphs showing injection pressure and flow rate. One graph must include, at a minimum, daily maximum injection pressure and daily average flow rate, on a single, monthly chart;

(c) A statement of the total volumes of the fluid injected to date, in the current calendar year, and the current month;

(d) A tabulation of the dates, amounts and types of liquid added to or removed from the annulus system during the month, and the cumulative additions and cumulative subtractions for the current month and each of the past 12 months;

(e) Any noncompliance with conditions of this permit, including but not limited to:

(1) Any event that exceeds operating parameters for annulus pressure or injection pressure or annulus/tubing differential as specified in the permit; or

(2) Any event that triggers an alarm or shutdown device required in Part II(B)(5) of this permit.

2. Quarterly Reports – The permittee shall report at least every quarter the results of the injection fluid analyses specified in the approved waste analysis plan as recorded in the administrative record for this permit. This report must include statements showing that the requirements of Part I(E)(10) and Part II(C)(3) have been met. Quarterly reporting periods shall begin on the first day of January, April, July, and October of each year.

3. Annual Reports - The permittee shall report the following at least every twelfth month:

(a) Results of ambient monitoring required by 40 CFR §146.13(d)(1) and Part II(C)(4) of this permit; and

(b) A certified statement attesting that no waste streams other than those identified in Part III(F) of this permit were injected into the well.

4 Reports on Well Tests and Workovers - Within 45 calendar days after the activity, the permittee shall report to the Director the results of demonstrations of mechanical integrity, any well workover, or results of other tests required by this permit.

PART III

This Part includes, but is not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, as required by 40 CFR Parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING, MONITORING, AND REPORTING REQUIREMENTS

B. PLUGGING AND ABANDONMENT PLAN

C. FINANCIAL ASSURANCE MECHANISM

D. CONTINGENT CORRECTIVE ACTION

E. CONSTRUCTION DETAILS

F. SOURCE AND ANALYSIS OF WASTE

G. APPROVED PROCEDURES FOR TESTING MECHANICAL INTEGRITY

PART III(A)
SUMMARY OF OPERATING, MONITORING, AND REPORTING REQUIREMENTS

	LIMITATION	MINIMUM MONITORING FREQUENCY	MINIMUM RECORDING FREQUENCY	MINIMUM REPORTING FREQUENCY
Injection Pressure*	2393 psig maximum**	continuous	continual	monthly
Annulus Pressure*	100 psig minimum	continuous	continual	monthly
Annulus-Tubing Differential*	100 psig minimum above operating injection pressure	continuous	continual	monthly
Flow Rate		continuous	continual	monthly
Cumulative Volume		continuous	monthly	monthly
Annulus Fluid Loss			monthly	monthly
Chemical Composition of Injected Fluids***			quarterly	quarterly
Physical Characteristics of Injected Fluids****			quarterly	quarterly

Sampling Location: The sample location will be at a manual spigot, located at the discharge point of the final filtration unit and the suction of the injection pumps.

* Record data points every 5 minutes and have a preset alarm that is triggered based on pressure data by any instantaneous read, the sample frequency will immediately change to every second to ensure a representative data snapshot is recorded. In situations where, after 10 minutes of every-second pressure recording, no additional pressure deviations are recorded, recording may return to normal intervals. **NOTE:** "Continuous" meaning ongoing without interruption; "continual" meaning ongoing, but with repeated interruptions.

**The limitation on injection pressure will serve to prevent injection-formation fracturing. This limitation was calculated using the following formula:

[{Fracture Gradient – (0.433 psi/ft × specific gravity)} × depth] - 14.7 psi.

The fracture gradient of 1.17 psi/ft was determined by site-specific testing of the injection zone. The Dundee Limestone at 3830 feet was used as the depth and a specific gravity of 1.25 was used for the injection fluid. If the permittee decides in the future to perforate the casing and inject directly into the Dundee Limestone, the permittee will be required to conduct approved in-situ stress tests, in which case the maximum injection pressure will be modified to reflect the specific

value of the fracture gradient in this well. Such modification shall be considered a minor modification as allowed for at 40 CFR §144.41(f).

*** As specified in the Sampling and Analysis Plan, found in the administrative record for this permit. At a minimum, this analysis shall include, but not be limited to, the following: pH, NaCl, KCl, SO_4, Br, Ca, Mg, NaOH, and $Na_4Fe(CN)\circ 10H2O$.

**** As specified in the Sampling and Analysis Plan, found in the administrative record for this permit. At a minimum, this analysis shall include, but not be limited to, the following: Temperature, Specific Conductance, and Specific Gravity.

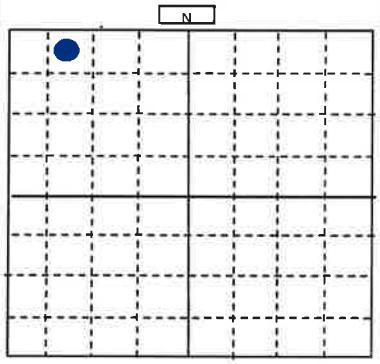
PART III(B)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

PLUGGING AND ABANDONMENT PLAN

WELL NAME & NUMBER, FIELD NAME, LEASE NAME & NUMBER	NAME, ADDRESS, & PHONE NUMBER OF OWNER / OPERATOR
Cargill, Incorporated Thomas 1-26 MI-133-1I-0002 Hersey, Michigan	Cargill, Incorporated 1395 135th Avenue Hersey, Michigan 49639

Locate Well and Outline Unit on Section Plat - 640 Acres



STATE	COUNTY	STATE PERMIT NUMBER
Michigan	Osceola	

SURFACE LOCATION DESCRIPTION
NE 1/4 of NW 1/4 of NW 1/4 of Section 26, Township 17N, Range 9W

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location: 460 ft. From (N/S) N Line of Quarter Section
And: 864 ft. From (E/W) W Line of Quarter Section

TYPE OF AUTHORIZATION
- [x] Individual Permit
- [ ] Rule
- [ ] Area Permit

Number of Wells in Area Permit: ____

US EPA Permit Number: MI-133-1I-0002

WELL ACTIVITY
- [x] Class I
  - [ ] Hazardous
  - [x] Nonhazardous
- [ ] Class II
  - [ ] Brine Disposal
  - [ ] Hydrocarbon Storage
  - [ ] Enhanced Recovery
- [ ] Class III
- [ ] Class IV

CASING/TUBING/CEMENT RECORD AFTER PLUGGING AND ABANDONMENT

Size	Wt (lb/ft) TBG/CSG	Original Amount (CSG)	CSG to be Left in Well	Hole Size	Sacks Cement Used	Type

METHOD OF EMPLACEMENT OF CEMENT PLUGS
- [ ] Balance Method
- [ ] Dump Bailer Method
- [ ] Two Plug Method
- [ ] Other

CEMENT TO PLUG AND ABANDON DATA	Plug # 1	Plug # 2	Plug # 3-5	Plug # 6	Plug # 7	Plug # 8
Size of Hole or Pipe in Which Plug Will Be Placed (inches)	9 5/8	9 5/8	9 5/8	13 3/8	13 3/8	13 3/8
Calculated Top of Plug (ft.)	3,900	3,300	900	300	150	0
Measured Top of Plug (ft.)						
Depth to Bottom of Plug (ft.)	4,150	3,900	3,300	900	300	150
Sacks of Cement to be Used	151	241	963	465	117	125
Slurry Volume to be Used (cu. Ft.)	127	304	1,213	586	147	147
Slurry Weight (lb./gal.)	15.9	14.15	Intervals	14.15	14.15	15.6
Type of Cement, Spacer or Other Material Used	Thixotropic Poz	50/50 Poz	50/50 Poz	50/50 Poz	50/50 Poz	Class A
Type of Preflush Used						

DESCRIPTION OF PLUGGING PROCEDURE

De-pressurize well and place in static state. Rig up workover rig and release packer. Circulate fluid from annulus and replace with brine. Reset packer and rig up cementing equipment. Pump Thixotropic cement down tubing and squeeze to formation. Wait on cement for 12 hours, then try to pump to formation. If formation will pressure up, proceed to plug. If formation will not take fluid, pump additional 25 sacks Thixotropic cement. Trip out of hole with 4" tubing and packer. Lay down packer to run back in open ended. Set plugs of 50/50 Poz from TD to within 150 to 200 feet of surface. Set last plug using Class A. Cut off 3 feet below surface and weld plate over casing.

ESTIMATED COST OF PLUGGING AND ABANDONMENT

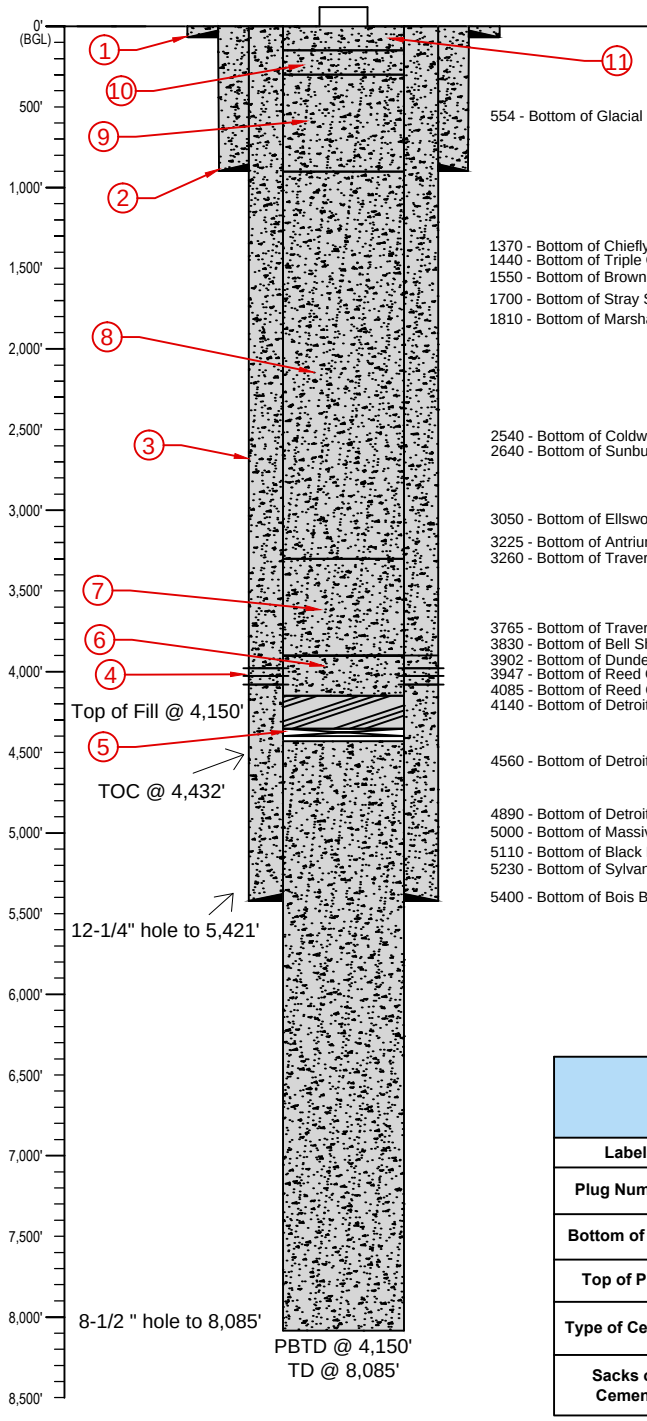
Costs for Cementing: $41,311.69; Costs for Rig: $40,000; Total Costs for Cementing: $81,311.69

CERTIFICATION

I certify under the penalty of law that I have examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref.40 CFR 144.32)

NAME AND OFFICIAL TITLE	SIGNATURE	DATE SIGNED
Lynne J. Tomaszewski, Mgr.		7-17-17

EPA Form 7520-14



554 - Bottom of Glacial Drift

1370 - Bottom of Chiefly Sandstone and Shale
1440 - Bottom of Triple Gypsum
1550 - Bottom of Brown Limestone
1700 - Bottom of Stray Sand
1810 - Bottom of Marshall Sandstone

2540 - Bottom of Coldwater Shale
2640 - Bottom of Sunbury Shale

3050 - Bottom of Ellsworth Shale
3225 - Bottom of Antrium Shale
3260 - Bottom of Traverse Formation

3765 - Bottom of Traverse Limestone
3830 - Bottom of Bell Shale
3902 - Bottom of Dundee Formation
3947 - Bottom of Reed City Anhydrite
4085 - Bottom of Reed City Dolomite
4140 - Bottom of Detroit River (Anhydrite)

4560 - Bottom of Detroit River Salt (Salt and Anhydrite)

4890 - Bottom of Detroit River Sour (Anhydrite & Dolomite)
5000 - Bottom of Massive Anhydrite & Richfield Zone
5110 - Bottom of Black Lime
5230 - Bottom of Sylvania Sandstone

5400 - Bottom of Bois Blanc Bass Island Group

GL:	1,121.6'
Depths are Ground Level unless otherwise noted	

Casing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	20"	13-3/8"	9-5/8"
Weight	NA	54.5 lb/ft	40 lb/ft
Material Grade	NA	K-55	N-80
Hole Size	Driven	17-1/2"	12-1/4"
Depth Set (GL)	68'	896'	5,421'
Cement	Driven	700 sx	1,700 sx

Perforation Information

Label	4
Type	Perf
Depth Set	3,928-4,080'

Tubing / Packer Information

Label	5
Type	Bridge Plug
Depth Set	4,406'

P&A Cement Information

Label	6	7	8	9	10	11
Plug Number	1	2	3-5	6	7	8
Bottom of Plug	4150	3900	3300	900	300	150
Top of Plug	3900	3300	900	300	150	0
Type of Cement	Thixotropic 50/50 Poz	50/50 Poz	50/50 Poz	50/50 Poz	50/50 Poz	Class A
Sacks of Cement	151	194	773	359	90	96

LONQUIST FIELD SERVICE
AUSTIN WICHITA HOUSTON CALGARY
1001 McKinney, Suite 1650
Houston, Texas 77002
Tel: 713.559.9950
Fax: 713.559.9959

Cargill, Incorporated

Thomas 1-26 P&A Well Schematic

Country: USA	**State/Province:** Michigan	**County/Parish:** Osceola
Lease Number: NA	**District:** NA	**Status:** Class I Disposal
Permit No: MI-133-1I-0002	**Field:** NA	**Ground Elevation:** 1,121.6'
Well API No: 21133003507	**Project No:** NA	**Date:** 06/28/2017
Drawn: CJG	**Reviewed:** PWJ	**Approved:** PWJ
Rev No: NA	**Notes:**	

PLOT: 6/28/2017 1:12 PM LAST SAVE: 6/28/2017 1:11 PM BY: CADSTATION FILE NAME: Y:\CLIENTPROJECTS\A-B\BLM SULPHUR MINES\WELL NO. 4\BOARDWALK – SULPHUR STORAGE WELL NO. 004 – F814\04_SCHEMATICS\WELLBORE\SULPHUR BRINE WELL NO.004 WELLBORE SCHEMATIC.V.1.2.DW

PART III(C)
FINANCIAL ASSURANCE MECHANISM

Cargill Incorporated has demonstrated adequate financial responsibility to properly plug and abandon the Class I non-hazardous well. If Financial Statement Coverage is used as financial mechanism to cover the cost of plugging the injection well, this coverage must be updated and sent to U.S. EPA on an annual basis.

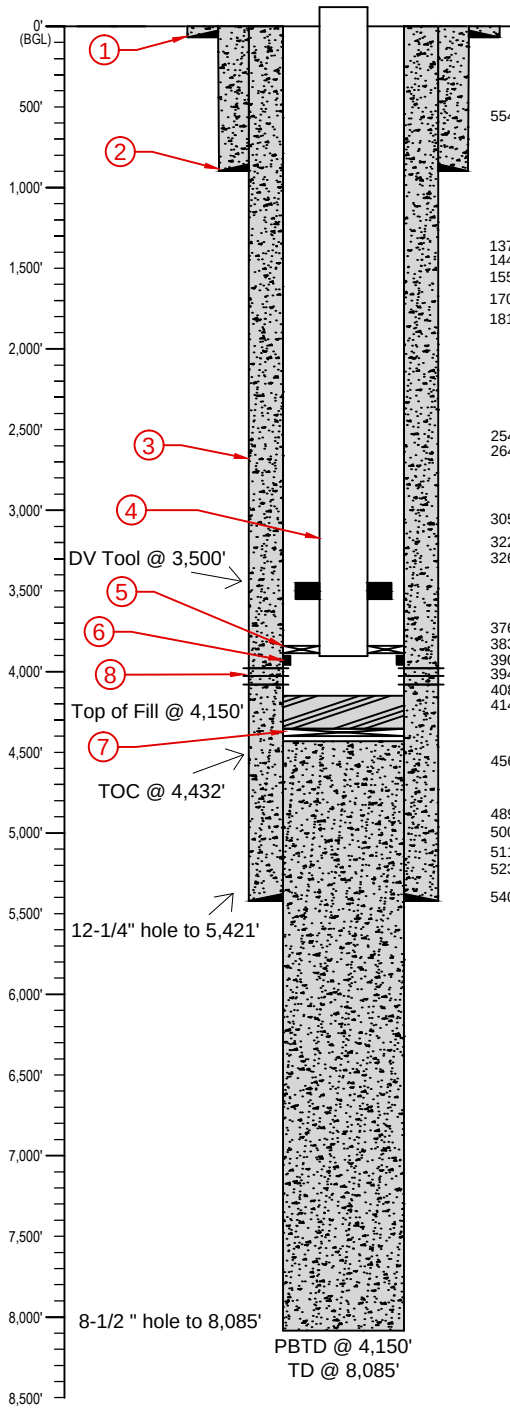
PART III(D)
CONTINGENT CORRECTIVE ACTION

The Area of review (AOR) for the Woodward #1-26 injection well is a two-mile radius around the well. Well records for all known wells drilled into the bedrock within the AOR have been reviewed. No wells appear to have been improperly completed or plugged and abandoned that might act to transmit fluids into the lowermost USDW. Therefore, no corrective action plan is required because there are no records indicating any artificial penetrations exist within the AOR that penetrate the confining or injection zones that have not been properly plugged and abandoned.

The following steps will be completed in the unlikely event that some unforeseen failure of the Woodward #1-26 well occurs that might jeopardize the USDW:

- Immediately halt operation of the well;
- Notify appropriate regulatory authorities of the discovery and the nature of the well failure (telephone notification within 24 hours; written confirmation within 5 days);
- Conduct an investigation into the cause of the well failure; develop corrective action plan to eliminate the problem; and
- Perform remedial work.

PART III(E)



554 - Bottom of Glacial Drift

1370 - Bottom of Chiefly Sandstone and Shale
1440 - Bottom of Triple Gypsum
1550 - Bottom of Brown Limestone
1700 - Bottom of Stray Sand
1810 - Bottom of Marshall Sandstone

2540 - Bottom of Coldwater Shale
2640 - Bottom of Sunbury Shale

3050 - Bottom of Ellsworth Shale
3225 - Bottom of Antrium Shale
3260 - Bottom of Traverse Formation

3765 - Bottom of Traverse Limestone
3830 - Bottom of Bell Shale
3902 - Bottom of Dundee Formation
3947 - Bottom of Reed City Anhydrite
4085 - Bottom of Reed City Dolomite
4140 - Bottom of Detroit River (Anhydrite)

4560 - Bottom of Detroit River Salt (Salt and Anhydrite)

4890 - Bottom of Detroit River Sour (Anhydrite & Dolomite)
5000 - Bottom of Massive Anhydrite & Richfield Zone
5110 - Bottom of Black Lime
5230 - Bottom of Sylvania Sandstone

5400 - Bottom of Bois Blanc Bass Island Group

GL:	1,121.6'
Depths are Ground Level unless otherwise noted	

Casing Information

Label	1	2	3
Type	Conductor	Surface	Production
OD	20"	13-3/8"	9-5/8"
Weight	NA	54.5 lb/ft	40 lb/ft
Material Grade	NA	K-55	N-80
Hole Size	Driven	17-1/2"	12-1/4"
Depth Set (GL)	68'	896'	5,421'
Cement	Driven	700 sx	1,700 sx

Tubing / Packer Information

Label	4	5	6	7
Type	Tubing	Packer	Packer Slips from Previous Packer	Bridge Plug
OD	4-1/2"	9-5/8"		
Weight	11.6#			
Material Grade	K-55 LT&C SMLS	Arrowset 1		
Depth Set	3,849'	3,845'	3,863'	4,406'

Perforation Information

Label	8
Type	Perf
Depth Set	3,928-4,080'

LONQUIST FIELD SERVICE

AUSTIN WICHITA HOUSTON CALGARY

1001 McKinney, Suite 1650
Houston, Texas 77002
Tel: 713.559.9950
Fax: 713.559.9959

Cargill, Incorporated

Thomas 1-26
Wellbore Schematic with Site Stratigraphy

Country: USA	**State/Province:** Michigan	**County/Parish:** Osceola
Lease Number: NA	**District:** NA	**Status:** Class I Disposal
Permit No: MI-133-1I-0002	**Field:** NA	**Ground Elevation:** 1,121.6'
Well API No: 21133003507	**Project No:** NA	**Date:** 06/28/2017
Drawn: CJG	**Reviewed:**PWJ	**Approved:** PWJ
Rev No: NA	**Notes:**	

PLOT: 6/28/2017 1:15 PM LAST SAVE: 6/28/2017 1:14 PM BY: CADSTATION FILE NAME: Y:\CLIENTPROJECTS\A-B\BLM SULPHUR MINES\WELL NO. 4\BOARDWALK – SULPHUR STORAGE WELL NO. 004 – F814\04_SCHEMATICS\WELLBORE\SULPHUR BRINE WELL NO.004 WELLBORE SCHEMATIC.V.1.2.DW

PART III(F)
SOURCE OF WASTE

Fluid disposed of into the Woodward #1-26 injection well, resulting from the solution mining of potash and salt, is comprised predominantly of sodium chloride (NaCl). Fresh water is pumped from the plant water well through condensers to provide process plant cooling. High pressure injection pumps then inject the water into the current development cavities to dissolve the NaCl. The cavity returns are sent to the brine holding tank where it is combined with other disposal streams. The brine is then pumped through a filter and injected in the disposal well. The following is a typical representation of the physical properties and chemical characteristics of the waste brine.

Physical Property	Range	Typical
Specific Gravity	1.0-1.2	1.2

Chemical Characteristics:

	Range	Typical
pH	5.5-8.0	7.0
	Weight Percent	
H_2O	variable	
NaCl	variable	
KCl	variable	
SO_4	<0.4	
Br	<0.2	
Ca	<0.2	
Mg	<0.02	
$Na_4Fe(CN)\ 10H_2O$	>1%	

Sodium hydroxide is used in the stripping of H_2S from the production brine. Pump packing seal water (<10gpm) and a bleed system (<10gpm) containing some sodium bisulfite from the H_2S stripping system are also added to the disposal waste stream. Boiler blowdown of typically less than 10 gpm, floor wash-down of less than 10 gpm and sodium ferrocyanate decahydrate (>1% by wt.), used as an anti-caking coating for salt, all become part of the disposal waste stream. A series of purge wells on the site intercept and pump groundwater containing chlorides (average concentration 7,456 mg/l) into the process stream that may partially reach the waste stream entering the injection well.

Biological Characteristics:

Disposal fluid originates primarily from the solution mining of salt and is essentially free of biological matter. Well water used to dissolve the salt may possibly contain biological matter, however, the high salinity of the disposal fluid would cause an overall decline in biological matter content.

Radiological Characteristics:

The disposal fluid will contain trace amounts of the naturally occurring stable ^{37}Cl isotope and radiogenic ^{40}K isotope associated with potassium chloride and sodium chloride.

PART III(G)
TESTING PROCEDURES

Standard Annulus Pressure Test

1. Ensure the packer is set within 100 feet of the top of the injection zone. Packers not set within 100 feet of the top of the injection zone will be evaluated by EPA on a case-by-case basis. Note any approved deviations from previously reported well construction.
2. Document the test using a mechanical or digital device or a service company job record which records the value of the parameters of interest as measured during the test.
3. Submit along with the test results a gauge calibration certificate for the mechanical or digital device used to record test parameters. All calibration (for new or recalibrated gauges) must have been performed within a year prior to the test.
4. Place a gauge on the wellhead to measure pressure. If a recording device is used, the recording device serves to verify the data witnessed on the wellhead gauge.
5. Use an appropriately scaled mechanical gauge which has a measurement range that is 1.2-2 times the maximum pressure measured or a 1 psi resolution digital gauge with sufficient full scale.
6. Measure and document pressure using a gauge and/or a digital record and/or a chart record that can be read with sufficient accuracy to identify pressure change which would result in a failure of the test and to record accurate values during the test interval. For example, if the test pressure is 300 psig, the gauge and/or chart record should be marked in increments of 5 psi or less.
7. Verify that the tubing/casing annulus is full of liquid. No unapproved fluids or substance which may affect test outcomes are allowed. Measure and report the volume of fluid added to the annulus during pressurization (if any). If an annulus tank is pressurized with nitrogen to pressurize the well, record the fluid displaced from the tank into the well annulus.
8. Stabilize the temperature of the well and the annulus liquid, either by ceasing injection or injecting at a constant fixed rate. Ensure that the wellhead injection tubing pressure is at least 100 psi different from the annulus test pressure.
9. Pressurize the annulus to the greater of 300 psig or the maximum permitted injection pressure plus 100 psi. A positive pressure differential of greater than 100 psi should be maintained between the annulus and the injection tubing. If EPA does not approve any deviations from these criteria prior to testing, the test results might not be considered a sufficient demonstration of mechanical integrity and a new test would then be needed. A net gain or loss of more than 3% during the test indicates the well does not have mechanical integrity. Following pressurization, isolate the annular system from its pressure source and, if present, the sealpot or surge tank being sure to prevent any leaking across the shut-off valves.
10. Test for at least 60 minutes. Note the time, the annulus pressure, and the injection/tubing pressure at the start of the test and measure and note these same parameters at least every 10 minutes thereafter up to the end of the required test duration.
11. Send a report of the testing including any other data or documents available at the conclusion of the test which support the test results, such as gauge calibration certification, third-party service ticket, and/or original chart/digital recordings, to EPA per the reporting requirements of the permit.

12. If the tested well was reworked in association with the test, submit a rework record.
13. Include the certification statement and signature on the transmittal letter or on the individual MIT results form and, if submitted, the rework record to comply with the requirements of 40 CFR § 144.32(b).

Fall-Off Test

1. Injection of normal injectate at the normal rate is preferred.
2. The injection period should be at least 50% longer than the planned shut-in time, or at minimum as long as operationally possible. During this time injection at a constant rate (+/- 10%) should be attempted.
3. The pressure gauge utilized for the pressure transient test shall have been calibrated no more than one year prior to the test date.
4. Place the pressure gauge downhole at approximately the top of the permitted injection zone at least one hour prior to ceasing injection.
5. Following at least one hour of pressure data collection during injection, shut-in the well as quickly as possible.
6. Collect data at a frequency of at least one data point every 10 seconds for at least the first five minutes after shut-in; between five and 30 minutes at no less than one reading every 30 seconds; and the operator can reduce frequency as required after 30 minutes.
7. End pressure measurements when pressure is relatively stable, when operational necessity dictates, when sufficient radial flow dominated data has been collected to allow evaluation of kh and extrapolation of pressure to infinite shut-in time is possible, or if boundary effects are observed.
8. The test shall include a written report by a knowledgeable well test analyst. Such report must explain any anomalies shown in the results.
9. The test report shall include an up-to-date well schematic, a copy of the dated calibration certificate for the gauge utilized, and digital pressure data on CD/flash drive/email in a spreadsheet format.
10. The test report shall include a tabulation of values for the following background parameters: EPA permit number, porosity, net thickness (ft), viscosity (cp), formation compressibility (per psi), long string casing inner diameter (in), open hole diameter (in), and Kelly bushing elevation (ft). The test report shall also include a tabulation of values for the following test specific parameters: test start date/time, test end date/time, test length (hr), depth reference (Kelly bushing or ground level), specific gravity of test fluid, test fluid compressibility (per psi), gauge depth (ft), gauge calibration date, pressure required to maintain tubing fluid to the surface (psi), final tubing fluid level (ft), final flow rate immediately prior to shutin (gpm), cumulative volume injected since last pressure equalization (gal), permeability-thickness (md-ft), skin factor, radius of investigation (ft), final measured flowing pressure (psi), final measured shut-in pressure (psi), and p* pressure (psi). Pressure gauge units (psia or psig) shall be specified.
11. The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

Radioactive Tracer Survey

1. The tool shall be calibrated by recording the tool response to rock formations of lithology known to produce a low reading, and to lithology known to produce a high reading.
2. Set the scaling at the same level for all phases. 40 counts per second per inch is usually effective.
3. Record a base log before any radioactive material is released in the well.
4. Use slugs large enough to ensure the maximum height of deflection caused by the slug is 50 times higher than the background.
5. Inject at the highest practicable rate during the slug tracking test, but at low enough velocity to allow the slug to be followed effectively.
6. If the slug moves upward outside of the tubing or splits during the tracking test, follow the slug upward to determine the limit of its upward movement.
7. Inject at the highest practicable rate during the stationary test.
8. Set the tool with the bottom detector within five feet above the end of the tail pipe, the casing shoe or the top perforation (whichever is deeper) during the stationary test; or if the slug moved upward during the tracking test, place the top detector above and the bottom detector below the highest level of upward movement detected during the tracking test. If the slug passes both detectors during the stationary test, move the tool up in steps to find the shallowest extent of movement.
9. The stationary test must be run for a minimum of 30 minutes and must be run long enough to be able to detect upward flow of 2 feet per minute.
10. Run a final base log after testing.
11. The test shall include a written report by a knowledgeable analyst. Such report must explain any anomalies shown in the results.
12. The test report shall include an up-to-date well schematic; digital logging data on CD/flash drive/email in a spreadsheet format; description or illustration of the logging tool with measurements of detector and ejector placement relative to the tool bottom; and plots of the logging activity including merged and unmerged slug tracking records, stationary test plot, initial base log, final base log, and superimposed initial and final base logs.
13. The test report shall include a tabulation of values for the following background parameters: EPA permit number, long string casing inner diameter (in), long string casing length (ft), tuing inner diameter (in), tubing length (ft), depth to top of packer (ft), depth to bottom of packer (ft), tail pipe inner diameter (in), tail pipe length (ft), tail pipe lowermost depth (ft), top of open hole or uppermost perforation (ft), open hole diameter (in), well total depth (ft), plugged back total depth or top of fill depth (ft), Kelly bushing elevation (ft), and as applicable depth to top of confining zone (ft), depth to top of permitted injection zone (ft), and depth to top of injection interval (ft). The test report shall also include a tabulation of values for the following test specific parameters: test date, depth reference (Kelly bushing or ground level), and injection rate for each test (gpm).
14. The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.

Temperature Log

1. To conduct a static temperature log, the well must be shut in for at least 36 hours, or longer if temperature stabilization based on previous logs requires more time.
2. If the well cannot be shut in for 36 hours, shut in for as long as possible and run two logs at least six hours apart.
3. Calibrate the temperature tool in a bucket of ambient temperature water and a bucket of ice water immediately prior to conducting the test.
4. Log from the top of the well to the bottom, recording both temperature and natural gamma ray activity.
5. Record log data at least once per foot.
6. Logging speed shall not exceed 30 feet per minute. Reduce speed to 20 feet per minute in air- filled well bores.
7. The test shall include a written report by a knowledgeable log analyst. Such report must explain any anomalies shown in the results.
8. The test report shall include an up-to-date well schematic, digital logging data on CD/flash drive/email in a spreadsheet format, and a plot of the logging activity.
9. The test report shall include a tabulation of values for the following background parameters: EPA permit number, long string casing length (ft), tubing and/or tail pipe lowermost depth (ft), top of open hole or uppermost perforation (ft), well total depth (ft), plugged back total depth or top of fill depth (ft), Kelly bushing elevation (ft), depth to top of confining zone (ft), and depth to top of permitted injection zone (ft). The test report shall also include a tabulation of values for the following test specific parameters: test date, depth reference (Kelly bushing or ground level), date of last injection, temperature of last injected fluid (F), elapsed time in hours since last injection (hr), volume injected into the well in the past year (gal), names and depths of any other injection formations used at the site, temperatures logged by the tool and thermometer during calibration (°F), depth to fluid level in the tubing (ft), depth to top of receptive strata (ft), and depth to bottom of receptive strata (ft).
10. The test must conclusively demonstrate its objectives and satisfy the Director to be considered a completed test.