OHIO ENVIRONMENTAL PROTECTION AGENCY

OHIO E.P.A.

SEP 24 2014

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I HAZARDOUS WELL

Ohio Permit No.: UIC 03-72-009-PTO-I
US EPA ID No.: OHD020273819

Date of Issuance: September 24, 2014
Effective Date: September 24, 2014
Date of Expiration: September 24, 2020

Name of Applicant: Vickery Environmental, Inc.
Well No. 2

I certify this to be a true and accurate copy of the official documents as filed in the records of the Ohio Environmental Protection Agency.

By: Larry Cassiter **Date:** 9-24-14

Mailing Address: 3956 State Route 412
Vickery, Ohio 43464

Facility Location: 3956 State Route 412
Vickery, Ohio 43464

County: Sandusky **Township:** Riley

Section: Section 26

Latitude/Longitude: 41° 22' 17"N / 82° 59' 6"W

Injection Interval: Mt. Simon from 2803 to 2950 feet KB

Containment Interval: Knox, Kerbel, Conasauga and Rome from 2360 to 2803 feet KB

Injection Zone: Knox, Kerbel, Conasauga, Rome and Mt. Simon from 2360 to 2950 feet KB

Confining Zone: Black River and Wells Creek from 1816 to 2360 feet KB

Pursuant to the Underground Injection Control rules of the Ohio Environmental Protection Agency codified at Chapter 3745-34 of the Ohio Administrative Code, the applicant (Permittee) indicated above is hereby authorized to operate a Class I injection well at the above location upon the express conditions that the permittee meet the restrictions set forth herein.

All references to Chapter 3745-34 of the Ohio Administrative Code (OAC) are to all rules 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, and F.

This permit shall become effective on 09/24/14 and shall remain in full force and effect during the life of the permit, unless 1) the statutory provisions of Section 3004(f), (g) or (m) of the Resource Conservation and Recovery Act ban or otherwise condition the authorizations in this permit; 2) the Agency promulgates rules pursuant to these sections which withdraw or otherwise condition the authorization in this permit; or 3) this permit is otherwise revoked, terminated, modified or reissued pursuant to OAC Rules 3745-34-23 and 3745-34-24. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable state and federal law or regulations.

This permit and the authorization to inject shall expire at midnight, unless terminated, on the date of expiration indicated.

Craig W. Butler, Director
Ohio Environmental Protection Agency

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PART I

GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in operation of 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 (USDW). Any underground injection activity not specifically authorized in this permit is prohibited. Compliance with this permit during its term constitutes compliance for purposes of enforcement with Sections 6111.043 and 6111.044 of the Ohio Revised Code (ORC). Such compliance does not constitute a defense to any action brought under ORC Sections 6109.31, 6109.32 or 6109.33 or any other common or statutory law other than ORC Sections 6111.043 and 6111.044. 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.

This permit does not relieve owners and operators of hazardous waste injection wells of their obligation to comply with any additional regulations or requirements under 15 U.S.C.A. §§ 2601 et seq. and 42 U.S.C.A. §§ 6901 et seq. or Chapter 3734 of the Ohio Revised Code and rules promulgated thereunder. If more stringent regulations or requirements are promulgated after issuance of this permit, this permit does not relieve the permittee of the obligation to comply with these additional regulations or requirements. This permit does not authorize any above ground generating, handling, storage, treatment or disposal facilities. Such activities must receive separate authorization under regulations promulgated pursuant to Chapter 3745 of the Ohio Administrative Code (OAC) and Part C of the federal Resource Conservation and Recovery Act.

B. PERMIT ACTIONS

1. <u>Modification, Revocation, Reissuance and Termination</u>. The Director may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with OAC Rules 3745-34-07, 3745-34-23, and 3745-34-24. Also, the permit is subject to minor modifications for cause as specified in OAC Rule 3745-34-25. 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 conditions.

2. Transfer of Permits. This permit may be transferred to a new owner or operator only if it is modified, or revoked and reissued, pursuant to OAC Rule 3745-34-22 (A), or 3745-34-23, as applicable.

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 any other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and OAC Rule 3745-34-03 any information submitted to the Ohio 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, the Ohio EPA may make the information available to the public without further notice. If a claim is asserted, documentation for the claim must be tendered and the validity of the claim will be assessed in accordance with the procedures in OAC Rule 3745-34-03. If the documentation for the claim of confidentiality is not received, the Ohio EPA may deny the claim without further inquiry. 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 receiving water.

E. DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all applicable UIC 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 OAC Rule 3745-34-19. Any permit noncompliance constitutes a violation of ORC Chapter 6109 or 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or denial of a permit renewal application. Such noncompliance also may be grounds for enforcement action under other applicable state and federal law.

2. Penalties for Violations of Permit Conditions. Any person who violates a permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapters 6109 or 6111. Any person who knowingly or recklessly 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 one hundred eighty (180) days before this permit expires.

   b. Permit Extensions. The conditions of an expired permit shall continue in force in accordance with ORC Section 119.06 until the effective date of a new permit, if:

      i. The permittee has submitted a timely and complete application for a new permit; and
      ii. The Director has not acted on said application.

   c. Enforcement. When the permittee is not in compliance with the conditions of the expiring or expired permit the Director may:

      i. Initiate enforcement action based upon the permit which has been continued;
      ii. Issue a notice of intent to deny the new permit. If a final action becomes effective to deny the permit, the owner or operator shall immediately cease operation of the well or be subject to enforcement action for operation of a Class I hazardous injection well without a permit;
      iii. Issue a new permit under ORC Section 6111.044 with appropriate conditions; or
      iv. Take other actions authorized by underground injection control regulations set forth in OAC Chapter 3745-34 or any other applicable regulations or laws.

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

5. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit. This may include accelerated or additional monitoring or testing or both. If such is performed, the data collected shall be submitted to Ohio EPA in a written report within ninety (90) days of completion of all related activities.

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) which are installed or used by the permittee to achieve compliance with the conditions of this permit. "Proper operation and maintenance" includes

effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. Duty to Provide Information. The permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for renewing, modifying, revoking and reissuing, or terminating this permit. To determine compliance with this permit, or to issue a new permit the permittee also shall furnish to the Director, upon request, copies of records required to be kept by this permit or applicable state or federal law.

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 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 ORC Chapter 6111 and OAC Chapter 3745-34, any substances or parameters at any location.

9. Records.

   a. The permittee shall retain copies of records of all monitoring information, including all calibration and maintenance records and all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least five (5) years from the date of the sample, measurement or report, or for the duration of the permitted life of the well, whichever is longer. This period may be extended by the request of the Director.

   b. The permittee shall maintain copies of records of all data required to complete the permit application form for this permit and any supplemental information submitted under ORC Rules 3745-34-12, 3745-34-13 and 3745-34-15 for a period of at least five (5) years from the date the application was signed or for the duration of the permitted life of the well, whichever is longer. This period may be extended by request of the Director.

c. The permittee shall retain copies of records concerning the nature and composition of all injected fluids pursuant to Part I (E) (10) and Part II (D) (1) of this permit until three (3) years after the completion of well closure which has been carried out in accordance with the approved closure plan, and consistent with OAC Rule 3745-34-61(F) (5).

d. The permittee shall continue to retain such copies of records after the retention period specified by paragraphs (a) to (c) above, unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records. At least ninety (90) days notice shall be provided prior to delivery of the records to the Director. The records shall be in a form acceptable to the Director.

e. Records of monitoring information shall include:

   i. The date, exact place, and time of sampling or measurements;
   ii. The name(s) of the individual(s) who performed the sampling or measurements;
   iii. A precise description of both sampling methodology and the handling and custody of samples;
   iv. The date(s) analyses or measurements were performed;
   v. The name(s) of the individual(s) who performed the analyses or measurements and the laboratory that performed the analyses or measurements;
   vi. The analytical techniques or methods used; and
   vii. All results of such analyses.

10. Monitoring. Samples of injected fluids and formation fluids and measurements taken for the purpose of any required monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rules 3745-34-38 and 3745-34-57 and any other monitoring required by applicable rule or this permit. Monitoring results shall be reported in accordance with OAC Rules 3745-34-38 and 3745-34-58 in a format acceptable to the Director and as set forth in Part I (E) (12) of this permit.

    a. The method used to obtain a representative sample of any fluid to be analyzed and the procedure for analysis of the sample shall comply with the method cited and described in Table I of 40 CFR Part 136.3 and/or Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Administrator of the U.S. EPA or the Director and shall be consistent with the Ohio EPA Quality Assurance Plan.

b. The monitoring information shall include conditions of quality assurance for each type of measurement required for reporting by the operator. Reference to established, published criteria shall be made whenever possible.

c. Sampling and analysis shall comply with the specifications of the Waste Analysis Plan required in Part II (D) (3) of this permit and OAC Rule 3745-34-57.

11. Signatory Requirements. All applications, reports or other information, required to be submitted by this permit, requested by the Director or submitted to the Director, shall be signed and certified in accordance with OAC Rule 3745-34-17.

12. Reporting Requirements.

a. Planned Changes. The permittee shall give written notice to the Director, as soon as possible, of any planned physical alternations or additions to the permitted facility. Replacements of equipment that are equivalent to existing equipment are not included in this requirement.

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

c. 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 in writing no later than thirty (30) days following each schedule date.

d. Twenty-four (24) Hour Reporting.

i. The permittee shall report to the Director any noncompliance which may endanger health or the environment. All available information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within twenty-four (24) hours:
   1. Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; or
   2. Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water; or
   3. Any failure to maintain mechanical integrity of the well as defined by OAC rule 3745-34-34.

ii A written submission also shall be provided within five (5) business days of the time the permittee becomes aware of instances of noncompliance identified in paragraph 12 (d) (i) above. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; the anticipated time it is expected to continue; whether the noncompliance has or has not been corrected; 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 permit condition 12 (d) (ii) above.

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 and corrected information in writing within ten (10) days.

g. Monthly reports specified in OAC Rule 3745-34-38 and Part II (E) (1) of this permit shall be submitted by the fifteenth day of the following month. Quarterly reports shall be submitted in accordance with Part II (E) (2) of this permit.

h. Within thirty (30) days of receipt of this permit, the person designated as responsible for submission of reports pursuant to OAC Rule 3745-34-17 shall certify to the Director that he or she has read and is personally familiar with all terms and conditions of this permit. The Director shall be notified within ten (10) business days, in writing, if the designee or position is changed.

F. CLOSURE (OAC RULES 3745-34-36 AND 3745-34-60)

1. Closure Plan. A plan for closure of the well that includes assurance of financial responsibility and information relating to well closure is required in accordance with OAC Rules 3745-34-36 and 3745-34-60. A plan was submitted by VEI on August 4, 1994, and approved, with revisions, by Ohio EPA on May 5, 1997. The approved Closure Plan is part of the Administrative Record of this permit and the permittee shall comply with the revised plan as if it were fully set forth herein. The implementation of the approved Closure Plan is a condition of this permit; however, the permittee must receive the approval of the Director to proceed before implementing this Plan. The permittee shall maintain and comply with this Plan and all applicable requirements in accordance with OAC Rule 3745-34-60. The obligation to implement the Closure Plan survives the termination of this permit or the cessation of injection.

2. Revision of Closure Plan. The permittee shall submit any proposed significant revision to the method of closure described in the Closure Plan for approval by the

Director no later than sixty (60) calendar days before closure, unless a shorter period of time is approved by the Director.

3. Notice of Intent to Close. The permittee shall notify the Director at least sixty (60) calendar days before closure of the well, unless a shorter notice period is approved by the Director.

4. Temporary Disuse. A permittee who wishes to cease injection for longer than twenty-four (24) months may keep the well open only if the permittee:

   a. Has received written authorization from the Director; and

   b. Has submitted a plan to the Director, for approval, that the owner or operator will follow to ensure that the well will not endanger USDWs during the period of temporary disuse. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells unless waived by the Director in writing.

   The owner or operator of a Class I hazardous waste injection well that has ceased operations for more than two (2) years shall notify the Director at least thirty (30) days prior to resuming operation of the well.

5. Closure Report. The permittee shall submit a closure report to the Director within the time frame established in OAC Rule 3745-34-60 (C). The report shall be certified as accurate by the permittee and by the person who performed the closure operation (if other than the owner or operator). Such report shall consist of the results of activities conducted by the permittee as required by parts I (F) (6) (a) and (b) of this permit, and either:

   a. A statement that the well was closed in accordance with the then effective Well Closure Plan; or

   b. Where actual closure differed from the then effective Well Closure Plan, a written statement specifying the differences between the plan and the actual closure.

6. Standards for Well Closure. Prior to closing the well, the permittee shall:

   a. Observe and record the pressure decay for a time and by a method specified by the Director;

   b. Conduct appropriate mechanical integrity testing of the well to ensure the integrity of that portion of the long string casing and cement that will be left in the ground after closure. Testing methods may include:

i. Pressure tests with liquid or gas;
ii. Radioactive tracer surveys;
iii. Noise, temperature, oxygen activation, pipe evaluation or cement bond logs;
iv. Any other test required by the Director.

c. Flush the well with a suitable buffer fluid.

7. Financial Responsibility for Closure. The owner or operator shall comply with closure financial assurance requirements of OC Rules 3745-34-36 (D) and 3745-34-62. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection.

G. POST-CLOSURE CARE (OAC RULE 3745-34-61)

1. Post-Closure Plan. A plan for post-closure activities, including assurance of financial responsibility, is required under OAC Rules 3745-34-36 and 3745-34-61. VEI submitted a Post-Closure Plan on August 4, 1994. The plan, with revisions, was approved by Ohio EPA on May 5, 1997. The approved Post-Closure Plan is part of the Administrative Record of this permit and the permittee shall comply with the revised plan as if it were fully set forth herein. The permittee shall maintain and comply with this Plan and all applicable requirements in accordance with OAC Rule 3745-34-61. The obligation to implement the Post-Closure Plan survives the termination of this permit or the cessation of injection.

This plan shall include the following information:

a. The pressure in the injection zone before injection began;

b. The anticipated pressure in the injection zone at the time of closure;

c. The predicted time until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the potentiometric surface of the lowermost USDW;

d. Predicted position of the waste front at closure;

e. The status of any corrective action for wells in the area of review;

f. The estimated cost of proposed post-closure care; and

g. An assurance of financial responsibility as required by OAC Rule 3745-34-62.

2. Post-Closure Corrective Action. The permittee shall continue and complete any corrective action required under OAC Rules 3745-34-30 and 3745-34-53.

3. Duration of Post-Closure Period. The permittee shall, at a minimum, continue post-closure maintenance and monitoring of any ground water monitoring wells required under this permit until pressure in the injection zone decays to the point that the injection well's cone of influence no longer intersects the base of the lowermost USDW, as identified in the Administrative Record for this permit, or for twelve (12) months after cessation of injection in all Class I UIC well at this site, whichever is longer. The Director may extend the period of post-closure monitoring upon a finding that a USDW may be endangered.

4. Survey Plat. The permittee shall submit a plat map to the local zoning authority upon closure of the well in accordance with the approved Closure Plan required in Part I (F) of this permit. The plat map shall indicate the location of the well relative to permanently surveyed benchmarks. A copy of the plat map shall be submitted to the Director.

5. Notification to State and Local Authority. The permittee shall provide appropriate notification and information to the Ohio Department of Natural Resources - Division of Mineral Resource Management, Technical Support Services Section, the Sandusky County Board of Health, and any other State or local authority designated by the Director upon closure of the well in accordance with the approved closure plan required in Part I (F) of this permit.

6. The Retention of Records. The permittee shall retain, for a period of three (3) years following well closure, records reflecting the nature, composition and volume of all injected fluids. The records shall be delivered to the Director at the end of the retention period.

7. Notice of Deed to Property. Upon closure of the well in accordance with the approved Closure Plan required in Part I (F) of this permit, the permittee shall record a notation on the deed to the facility property, or on some other instrument which is normally examined during title search, that will in perpetuity provide any potential purchaser of the property with the following information:

   a. The fact that land has been used to manage and dispose hazardous waste(s) in deep wells;

   b. The name(s) of the State agencies or local authorities with which the plat map was filed; and

   c. The type and volume of waste injected, the injection interval into which it was injected, the name(s) of the generator(s) of the waste and the period over which injection occurred.

8. Financial Responsibility for Post-Closure Care. The owner or operator shall comply with post-closure financial assurance requirements of OAC Rules 3745-34-36 (D)

and 3745-34-62. The obligation to maintain financial responsibility for post-closure care survives the termination of this permit or the cessation of injection.

H. MECHANICAL INTEGRITY

1. Standards. Each injection well shall maintain mechanical integrity as defined by OAC Rule 3745-34-34. The Director or his authorized representative shall be present during the test for demonstration of mechanical integrity, unless the Director or his authorized representative waives this requirement before the test occurs. In accordance with OAC Rule 3745-34-56 (D), the owner or operator of a Class I hazardous waste injection well shall maintain mechanical integrity of the injection well at all times.

2. Periodic Mechanical Integrity Testing [OAC 3745-34-57]. 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 OAC Rule 3745-34-57 (I) (1) 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. The bottom hole cement shall be tested by means of an approved radioactive tracer survey in accordance with OAC Rule 3745-34-57 (I) (2) at least once every twelfth month beginning with the date of the last approved demonstration;

   c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I) (3) at least once every thirty-six (36) 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;

   d. An approved casing inspection log shall be run for the entire length of the long string casing in accordance with OAC Rule 3745-34-57 (I) (4) whenever the owner or operator conducts a workover in which the injection string is pulled, unless the Director waives this requirement due to well construction or other factors which limit the test's reliability, or based upon the satisfactory results of a casing inspection log run within the previous five years. The Director may require that a casing inspection log be run every five years, if he or she has reason to believe that the integrity of the long string casing of the well may be adversely affected by naturally occurring or man-made events;

e. The permittee may request the Director to use any other test approved by the Administrator of the U.S. EPA in accordance with the procedures in OAC Rules 3745-34-34 (D) and 3745-34-57 (I) (5).

3. Prior Notice and Report.

a. The permittee shall notify the Director of intent to demonstrate mechanical integrity at least thirty (30) calendar days prior to such demonstration. For those tests required in Part I (H) (2) (b, c and d) above, the permittee shall submit the planned test procedures to the Director for approval at the time of notification. At the discretion of the Director a shorter time period may be allowed. Plans for pressure testing of the long string casing, injection tubing and annular seal shall specify the planned test pressure. Reports of mechanical integrity demonstrations which include well logs shall include an interpretation of results by a knowledgeable log analyst. Such reports shall be submitted in accordance with the reporting requirements established in Part II (E) (3) of this permit.

b. In accordance with OAC Rule 3745-34-56 (J), the permittee shall submit a plan for approval to the Director prior to conducting any well work over which requires the removal of the injection tubing. This plan shall be submitted forty five (45) days prior to plan implementation. A shorter time period may be allowed at the Director's discretion.

c. The permittee shall notify the Director of intent to conduct any well stimulation at least forty five (45) days prior to such procedures. A plan for well stimulation shall be submitted to the Director for review at the time of notification. Reports on well stimulation shall be submitted in accordance with the reporting requirements established in Part II (E) (3) of this permit.

4. Gauges. The permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half (0.5) percent of full scale prior to each required test of mechanical integrity or, barring any damage to the gauge, every six (6) months. 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 (5) 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 OAC Rule 3745-34-34 is indicated 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 From Director. The permittee shall demonstrate mechanical integrity at any time upon written request from the Director.

I. FINANCIAL RESPONSIBILITY

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC Chapter 3745-34. The 2007 financial assurance mechanism which addresses closure of the four permitted Class I hazardous injection wells and closure and post-closure of the ground water monitoring wells in the Knox-Kerbel and Lockport Formations is provided in Attachment A of this permit.

   a. The permittee shall maintain written cost estimates, in current dollars, for the Closure and Post-Closure Plans as specified in OAC Chapter 3745-34. The closure and post-closure cost estimates shall equal the maximum cost of closure and post-closure at any point in the life of the facility operation.

   b. The permittee shall adjust the cost estimate of closure and post-closure for inflation annually. This annually adjusted closure and post-closure cost shall be submitted with the annual financial assurance to the Director in accordance with requirements set forth in OAC Rules 3745-55-42 and 3745-55-44 as applicable.

   c. The permittee shall revise the closure and/or post-closure cost estimate whenever a change in the Closure Plan and/or Post-Closure Plan increases the cost of closure and/or post-closure. The revised cost estimates shall be adjusted for inflation as specified above in permit condition I (1) (b).
   d. If the revised closure and post-closure estimates exceed the current amount of the financial assurance mechanism, the permittee shall submit a revised mechanism to cover the increased cost within thirty (30) business days after the revision specified in permit conditions I (1) (b) and (c) above.
   e. The permittee shall keep on file at the facility a copy of the latest closure and post-closure cost estimate prepared in accordance with OAC Rules 3745-34-09 (B) (9) and 3745-34-62 during the operating life of the facility. Said estimate shall be available for inspection in accordance with the procedures in permit condition Part I (E) (8) (b) of this permit.

2. Insolvency. In the event of:

   a. The bankruptcy of the trustee or issuing institution of the financial mechanism (not applicable to permittees using a financial statement); or

   b. Suspension or revocation of the authority of the trustee institution to act as trustee; or

c. The institution issuing the financial mechanism losing its authority to issue such an instrument; the permittee shall notify the Director, in writing, within ten (10) business days.

The owner or operator shall establish other financial assurance or liability coverage acceptable to the Director, within sixty (60) days after such an event.

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

J. CORRECTIVE ACTION

1. Wells in the Area of Review. The permittee shall comply with the Corrective Action Plan (Attachment E to this permit), and with OAC Rules 3745-34-07, 3745-34-30 and 3745-34-53.

2. §3004(u) of the Resource Conservation and Recovery Act. The permittee shall comply with applicable corrective action requirements for the permitted well as required by the Resource Conservation and Recovery Act.

K. FEES

The permittee shall annually submit required fees in accordance with OAC Rule 3745-34-63 and shall submit any other applicable Class I Underground Injection fees specified in ORC 3734-18.

PART II

WELL SPECIFIC CONDITIONS FOR UIC PERMITS

A. CONSTRUCTION

1. Siting [OAC Rules 3745-34-37 and 3745-34-51]. The injection well shall directly place injectate only into the injection interval as defined on the cover page of this permit. At no time shall injection occur directly into any formation(s) above the injection interval.

2. Casing and Cementing [OAC Rules 3745-34-37(B) and 3745-34-54]. Notwithstanding any other provisions of this permit, the permittee shall maintain casing and cement in the well in such a manner as to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of the well at the time of permit issuance are shown in Attachment C of this permit. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation in accordance with OAC Rule 3745-34-56(J) and Part I(H)(3)(b) of this permit.

3. Tubing and Packer Specifications [OAC Rules 3745-34-37 (C) and 3745-34-54 (D)]. Injection shall take place only through approved tubing with an approved packer set within the casing at the bottom of the long string casing at a point approved by the Director, immediately above or within the injection interval. Tubing and packer specifications shall be as represented in engineering drawings contained in Attachment C of this permit unless altered due to an Agency approved well workover. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation in accordance with OAC Rule 3745-34-56 (J) and Part I (H) (3) (b) of this permit.

4. Wellhead Specifications. A quarter-inch (1/4") female coupling shall be maintained on the wellhead, to be used for independent injection pressure readings.

B. FORMATION DATA

1. Data on the injection and confining zones are contained in Attachment B of this permit. The permittee's determination or calculation at the time of permit issuance of the following information concerning the injection interval also appears in Attachment B.

   a. Formation fluid pressure;
   b. Estimated formation fracture pressure; and
   c. Physical and chemical characteristics of the formation.

2. In accordance with OAC Rule 3745-34-57 (J), the permittee shall monitor the pressure buildup in the injection zone at least every twelfth month beginning with the date of the completion of the last approved monitoring event. The permittee shall schedule pressure buildup testing such that one of the permittee's four Class I injection wells is tested each year and each well shall be tested at least once every forty-eight (48) months. This shall include, at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure fall-off curve. A plan for such monitoring shall be submitted for the Director's review and approval at least thirty (30) days prior to initiating monitoring or testing. The results of this test shall be used to calculate the following:

   a. The transmissivity of the injection zone;
   b. The formation or reservoir pressure; and
   c. The skin effect.

   The results of this test and the permittee's interpretation of the results shall be submitted to the Ohio EPA in accordance with OAC Rule 3745-34-58 (B) and Part II (E) (3) of this permit.

C. OPERATIONS

1. Injection Interval. Injection shall be limited to the Mt. Simon Sandstone in the approximate subsurface interval between 2803 feet and 2950 feet below kelly bushing (KB) for Vickery Environmental, Inc. Well #2.

2. Injection Pressure Limitation [OAC Rules 3745-34-38 (A) and 3745-34-56 (A)]. Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. 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 an underground source of drinking water.

   Bottom hole pressure shall be limited so that a maximum of 2102 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 2803 feet KB. The injection pressure shall be limited so that a maximum pressure of 751 psig (measured at the surface) is not exceeded. The maximum surface injection pressure limit shall be adjusted downward if fluid specific gravity increases above 1.113, in accordance with the calculation set forth in Attachment D of this permit. Regardless of the fluid specific gravity, a fracture gradient of 0.75 psi/ft shall not be exceeded under any circumstances.

   Vickery Environmental, Inc. submitted a report to the Director August 5, 1994, which demonstrated that the permitted maximum injection pressure meets the requirements of OAC Rule 3745-34-38 (A) (1) and 3745-34-56 (A). The report was accepted by Ohio EPA on March 24, 1995.

3. Injection Rate Limitation. The combined monthly average injection rate for all permitted Class I injection wells at this facility shall not exceed 240 gallons per minute. The rate shall be calculated utilizing the total volume of fluid injected for a given month divided by the total number of minutes within that month.

4. Additional Injection Limitation. No substances other than those meeting the following limitations shall be injected:

   a. Substances acceptable for receipt and defined as non-hazardous; or
   b. Substances authorized for receipt by applicable state and/or federal hazardous waste permits. If such substances are restricted from land disposal, the substance shall be authorized for disposal by the exemption to the land disposal restrictions under 40 CFR Part 148 granted by the U.S. EPA.

   The composite waste stream shall meet all compatibility requirements of OAC Rule 3745-34-57.

   Fluids containing polychlorinated biphenyls (PCBs) may be injected within the following limitations:

   a. The permittee shall comply with PCB concentration limitations as established in 40 CFR Part 761, Subpart D; and
   b. The permittee shall comply with PCB limitations of all applicable permits and administrative orders issued to the permittee.

   The permittee shall submit a certified statement attesting to compliance with these requirements annually with the submission of the fourth quarterly report. The only exception to these limitations is the injection of non-hazardous fluids recovered from monitor wells and other non-hazardous fluids required for approved well testing and/or monitoring.

5. Annulus Fluid and Pressure [OAC Rule 3745-34-56 (C)]. Except during workovers, the annulus between the injection tubing and the long string casing shall be filled with an inert, non-reactive fluid. The pressure on the annulus shall be at least fifty (50) psig higher than injection pressure at all times throughout the injection tubing length, for the purpose of leak detection. Temporary deviations from this fifty (50) psig positive differential requirement, which are part of normal well start-up and shut-down operations or an approved well stimulation, are authorized with the following conditions:

   a. Deviations may not exceed fifteen (15) minutes duration; and
   b. A positive pressure differential is required to be maintained at all times.

This 15 minute maximum time allowance applies only to this permit parameter and does not apply to any other permit parameter that is required to be maintained continuously. All instances of deviation from the fifty (50) psig positive differential are subject to reporting requirements in Part II (E) of this permit.

6. Automatic Warning and Shut-Off System.

   a. The permittee shall continuously operate and maintain an automatic warning and shut-off system required by OAC rule 3745-34-56 which shall stop injection in the following situation:

      i. Injection pressure measured at the wellhead reaches 788 psig;
      ii. Bottomhole pressure reaches 2109 psi;
      iii. When injection/annulus pressure differential falls below fifty (50) psig, except during conditions specified above in Part II (C) (5).

      Written plans and specifications for a warning and shut-off system that fulfill these requirements were submitted to the Director July 29, 1994, and approved on July 14, 1995.

   b. The permittee shall test the automatic warning and shut-off system at least once every twelfth month from the date of the last approved demonstration. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or his or her representative. The permittee shall notify the Director of their intent to test the automatic warning and shut-off system at least thirty (30) calendar days prior to such a demonstration. At the discretion of the Director a shorter time period may be allowed. The permittee shall submit the planned automatic warning and shut-off system test procedures to the Director for approval at the time of notification.

   c. If an automatic alarm or shutdown is triggered, the owner or operator shall investigate immediately and identify as expeditiously as possible the cause of the alarm to shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under OAC Rule 3745-34-56 (F) otherwise indicates that the well may be lacking mechanical integrity, the owner or operator shall:

      i. Immediately cease injection of waste fluids unless authorized by the Director to continue or resume injection; and
      ii. Take all necessary steps to determine the presence or absence of a leak; and,
      iii. Notify the Director within twenty-four (24) hours after alarm or shutdown in accordance with Part I (E) (11) of this permit.

7. Precautions to Prevent Well Blowouts. The permittee shall, at all times, maintain a pressure at the wellhead which will prevent the return of the injection fluid to

the surface. If there is gas formation in the injection zone near the well bore, such gas must be prevented from entering the casing or tubing. 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 which can resist the pressure differential. A blowout preventer shall be kept in proper operational status during workovers.

D. MONITORING

1. Monitoring Requirements [OAC Rules 3745-34-38 (B) and 3745-34-57 (A)-(F)]. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rules 3745-34-38 and 3745-34-57 and any other monitoring required by applicable rule or this permit. The method used to obtain a representative sample of any fluid to be analyzed and the procedure for analysis of the sample shall be the one described in Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Director.

2. Injection Fluid Analysis (OAC Rules 3745-34-38 and 3745-34-57).
   a. The injected fluids shall be analyzed no less frequently than monthly for parameters which include, at a minimum, those listed below. A final list of parameters is included in the approved Waste Analysis Plan.

i. pH	viii. Chlorides
ii. Specific Gravity	ix. Total Chromium
iii. Total Organic Carbon (TOC)	x. Total Iron
iv. Sulfate (SO_4)	xi. Total Nickel
v. Acidity (as $CaCO_3$)	xii. Total Zinc
vi. Total Solids @105°C	xiii. Total Lead
vii. Total Suspended Solids	xiv. Conductivity @25°C

   Results of the most recent analyses shall be submitted with each monthly operating report. The report must include statements demonstrating that the permittee is in compliance with the requirements of Part I (E) (10), Part II (C) (4) and Part II (D)(1) of this permit.

   b. Injection fluids shall also be analyzed no less frequently than quarterly for parameters which include at a minimum, those listed below. A final list of parameters is included in the approved Waste Analysis Plan.

i. Total Copper	xiv. Acetone
ii. Total Mercury	xv. Benzene
iii. Total Magnesium	xvi. Chlorobenzene
iv. Total Aluminum	xvii. 1, 2-Dichloroethane
v. Total Calcium	xviii. Ethylbenzene

vi. Total Manganese
vii. Total Potassium
viii. Total Sodium
ix Total Tin
x. Fluoride
xi. Nitrates
xii. Phenols
xiii. Sulfides
xix. Methyl ethyl ketone
xx. Methyl isobutyl ketone
xxi. Methylene chloride
xxii. Toluene
xxiii. 1,1,1-Trichloroethane
xxiv. Trichloroethylene
xxv. Xylene

Results of the most recent analysis shall be submitted with each quarterly report. The report shall include statements demonstrating that the permittee is in compliance with the requirements of Part I (E) (10), Part II (C) (4) and Part II (D) (1) of this permit.

3. <u>Waste Analysis Plan [OAC Rule 3745-34-57)]</u>.

a. The permittee has developed a written Waste Analysis Plan which describes the procedures which he or she will carry out to comply with permit conditions (D) (1) and (D) (2) above and Rule 3745-34-57 of the OAC. The latest revision of this plan was approved by Ohio EPA on June 7, 2001. A copy of the plan shall be kept at the facility and be available for inspection. The sampling and analyses shall be performed in a manner consistent with the Ohio EPA Quality Assurance Plan requirements. At a minimum, the plan must specify:

i. The parameters for which each hazardous waste will be analyzed and the rationale for the selection of these parameters;
ii. The test methods which will be used to test for these parameters; and
iii. The sampling method which will be used to obtain a representative sample of the waste to be analyzed, the frequency of sampling and analysis for each parameter.

The injectate sampling location shall be at the pumphouse associated with the well that is injecting. The permittee shall identify the types of tests and methods used to generate the monitoring data. The monitoring program shall conform to the one described in an approved Waste Analysis Plan. The permittee shall abide by the Quality Assurance Form (Attachment F) of this permit. This form shall be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

The permittee shall assure that the Waste Analysis Plan (WAP) remains accurate and the analyses of any fluid sampled remain representative.

b. The permittee has adequately demonstrated that the current composite waste stream injected will not adversely affect the injection zone, the confining zone and well construction materials with which the waste is expected to come into contact, based upon the standards of OAC Rule 3745-34-57 (E) and (F). Should process or operating changes occur that may significantly alter the characteristics of the composite waste stream injected, the permittee shall again demonstrate to the satisfaction of the Director that the compatibility standards are met, in accordance with OAC Rule 3745-34-57. Should the results of corrosion monitoring, well testing or composite waste stream (injectate) analyses, required by this permit or Chapter 3745-34 of the OAC, indicate that waste compatibility standards of OAC Rule 3745-34-57 have not been adequately addressed, the Director may:

i. Restrict certain incompatible wastes from being injected; or
ii. Require the permittee to make appropriate changes in well construction materials; or
iii. Require the permittee to conduct additional waste compatibility studies.

4. Continuous Monitoring and Recording Devices (OAC Rules 3745-34-38 (B) and 3745-34-56 (F). Continuous monitoring and recording devices shall be maintained and operated to monitor surface injection pressure, flow rate, the pressure in the annulus between the tubing and the long string of casing, and the temperature of the injectate. Continuous monitoring devices shall be maintained and operated to monitor the injected volume and the specific gravity of the injectate. The total injected volume for the well shall be recorded at least daily. Written plans for specific gravity recording and reporting which fulfill these requirements were submitted to the Director July 13, 1994, and approved on September 7, 1994.

5. Monitoring Wells. One ground water monitoring well has been installed in the Knox and Kerbel Formations and one in the Lockport Formation (lowermost USDW) in accordance with the Ground Water Monitoring Plan. The latest revision of this plan was approved by the Director on April 20, 1998. A copy of the most recently approved plan shall be kept at the facility and available for inspection. The permittee shall monitor the ground water monitoring wells for parameters and at the frequency described in the approved Ground Water Monitoring Plan and shall analyze the data according to procedures and at the frequency described in the approved Ground Water Monitoring Plan. Additional monitoring wells and/or appropriate corrective action may be required upon a determination of the Director, based upon data submitted in accordance with Part II (D) of this permit and any additional pertinent data, that such monitoring and/or action are necessary to determine whether a USDW may be endangered.

6. Compatibility of Well Material. The permittee shall monitor continuously for corrosion of the construction materials by a method approved by the Director in accordance with OAC Rule 3745-34-57. The Corrosion Monitoring Plan was approved by the Director on August 7, 1995. The latest revisions to the plan were accepted by Ohio EPA on April 5, 2001.The revised Corrosion Monitoring Plan was approved by the Director on September 20, 2001. The permittee shall report change

in mass or thickness; cracking; pitting; and other signs of corrosion at least quarterly in accordance with Part II (E) (2) of this permit.

7. Seismic Monitoring.

   a. Seismic Reflection Data. The permittee has completed a seismic reflection data study to the Director's satisfaction as indicated in September 9, 1991, Ohio EPA correspondence. The purpose of this study is to establish the presence or absence of significant geological structural features such as faults and/or fractures in the uppermost Precambrian rock units and the overlying Paleozoic rock units within the area of review at the Vickery, Ohio Class I injection well facility.

      If the area of review for this facility changes during the operational life of this well, the permittee shall re-evaluate the data obtained from the existing study. If after re-evaluation of the existing data, the Director determines the study to be inadequate to determine the presence or absence of geologic faults or fractures within the altered area of review, the permittee shall submit such additional seismic reflection data as the Director determines to be necessary.

   b. Seismic Monitoring System. Should monitoring data required by this permit or other pertinent geologic data indicate that injection operations at this site may be inducing seismic activity, the Director may modify this permit to require the permittee to install and continuously operate a seismic monitoring system, in accordance with OAC Rules 3745-34-23 and 3745-34-57 (K). The monitoring system specifications, reporting frequency, and content shall be established in a monitoring plan to be submitted to the Director for approval.

E. REPORTING REQUIREMENTS [OAC Rules 3745-34-28, 3745-34-38 (D), and 3745-34-58]

Specific reporting requirements of this permit in no way relieve the permittee of other applicable reporting requirements specified in any action of Ohio EPA or a court of appropriate authority.

1. Monthly Reports. The permittee shall submit monthly reports to the Director containing all of the information listed below and in format acceptable to the Director. The permittee shall refer to guidance prepared by Ohio EPA in development of monthly reports.

   a. A summary containing a description of the following events:

      i. Any non-compliance with conditions of the permit including but not limited to events that violate maximum or minimum limits for surface injection pressure, bottom hole pressure or annulus/injection differential pressure.

Report the date, the nature and cause of the non-compliance and the response taken;

ii. Any event which triggers an alarm or shutdown device required in Part II (C) (6) of this permit. This description is required for alarm events designed to address circumstances described in Part II (C) (6) (a) (i) through (iii) of this permit and all well shutdown occurrences. Report the date, the cause of the alarm or shutdown, the alarm or shutdown setpoint, the actual value triggering the alarm or shutdown, the response taken and specify whether an alarm or shutdown occurred;

iii. Any non-operating period. Report the date, duration and cause of the non-operating period;

iv. Any procedures conducted at the injection well other than routine procedures. Report the date and the reason for the non-routine operating procedures;

v. Any annulus fluid addition to or removal from the annulus system. Report the date, the time and cause for the addition or removal, the volume of fluid added or removed and specify fluid addition or removal;

vi. Any periodic mechanical integrity testing. Report the date, the reason for the testing and the type of test(s);

vii. Any well workover. Report the date, the reason for the workover and the work completed;

viii. Any other testing of the injection well required by the Director. Report the date, the reason for testing and the type of test(s).

b. A graph showing, in contrasting symbols or colors, for each day of the month:

i. Maximum surface injection pressure;
ii. Maximum bottom hole pressure; and,
iii. Minimum annulus/injection differential pressure.

The permitted maximum surface injection pressure and bottom hole pressure and the permitted minimum annulus/injection differential pressure should be demarcated on the graph. Data representing these graphed values, data representing injection pressure and specific gravity values utilized in calculations of the graphed (daily maximum) bottom hole pressures, and four hour data for the graphed parameters as well as injectate temperature shall also be presented in tabular form.

c. A graph showing injectate temperature (^{o}F), annular fluid volume (gallons) and sight glass level (inches) for each day of the month. Measurements for these three parameters shall be collected concurrently at a designated time each day. The data also shall be presented in tabular form.

d. Daily maximum, minimum and average injectate specific gravity.

e. The monthly maximum, minimum and average values for surface injection pressure, annulus pressure, flow rate in gallons per minute and volume. For each maximum and minimum flow rate reported, list the surface injection pressure and annulus pressure occurring during the time the well was operating at this maximum or minimum rate.

f. The total volume of fluid injected into this well for the month and to date.
g. The cumulative volume of fluid injected at the facility for the month and to date.
h. The combined monthly average flow rate for all operating wells, to be calculated as specified in Attachment D of this permit.
i. The status of and scheduled date(s) for sampling of UIC ground water monitoring wells.
j. Results of injection fluid analyses, specified in Part II (D) (2) (a) of the permit, completed during the month.

2. Quarterly Reports [OAC Rule 3745-34-58]. The permittee shall report all of the following each calendar quarter within fifteen (15) days after the end of the quarter:

   a. Results of the continuous corrosion monitoring system, and an interpretation of the results, as stipulated in Part II (D) (6) of this permit;
   b. Results of ground water monitoring, and an interpretation of the results, as specified in the approved Ground Water Monitoring Plan and as required in Part II (D)(5) of this permit; and
   c. Results of injectate analyses as stipulated in Part II (D) (2) (b) of this permit.

3. Reports on Well Tests and Workovers. Within thirty (30) calendar days after the activity the permittee shall submit to the Director the field results of demonstrations of mechanical integrity, any well workover or results of other tests required by this permit. A formal written report and interpretation of demonstrations of mechanical integrity (excluding annulus pressure tests), any well workover, or results of other tests, except those reports that include data and analysis of pressure buildup monitoring, required by this permit or otherwise required by the Director shall be submitted to the Director within forty-five (45) calendar days after completion of the activity. Those reports that include data and analysis of pressure buildup monitoring shall be submitted to the Director within sixty (60) days after completion of the activity.

4. The Permittee shall submit all required reports to:

   Ohio Environmental Protection Agency
   Division of Drinking and Ground Waters
   Underground Injection Control Unit
   50 West Town Street, Suite 700
   P.O. Box 1049
   Columbus, Ohio 43216-1049

5. The Permittee shall adhere to the reporting requirements specified in Attachment D and Part II of this permit for reporting under permit condition Part II (E) above.

F. CLASS I HAZARDOUS WASTE MANIFEST

Permittees injecting hazardous wastes which are accompanied by a manifest or delivery document shall comply with the requirements of OAC Rule 3745-65-70 or OAC Rule 3745-54-70, whichever is applicable.

G. WASTE MINIMIZATION

The permittee shall comply with Section 6111.045 of the Ohio Revised Code concerning the preparation, adoption and maintenance of a Waste Minimization and Treatment Plan. The permittee developed a facility Waste Minimization and Treatment Plan which was adopted on May 28, 1994. The plan shall be retained at the facility and shall be made available for inspection. Every three (3) years, on or before the anniversary date of the adopted plan, the permittee is required to submit to the Director a revised Executive Summary of the plan.

ATTACHMENT A

CLOSURE AND POST-CLOSURE COST ESTIMATES & FINANCIAL ASSURANCE

SECTION 1

CLOSURE COST ESTIMATE ASSUMPTIONS

TANK INVENTORY

TANK	VOLUME GALLONS
V-4	6,000
V-5	6,000
V-6	6,000
V-7	6,000
T-1	200,000
T-2	200,000
T-5	200,000
T-6	200,000
T-9	100,000
T-10	100,000
FAT-3R	11,750
FAT-5R	11,750
LAB TANK	2,500
TOTAL	1,050,000

SECTION 1 (CONT)

DISPOSAL COST ASSUMPTIONS

LIQUID DISPOSAL	$/GAL
DISPOSAL (GROUNDWATER, RINSE WATER)	$0.28
TRANSPORTATION $800/LOAD WITH 4,500 GALS/TRUCK	$0.18
TOTAL DISPOSAL & TRANS FOR LIQUID INVENTORY	$0.46
DISPOSAL (SCRUBBER WATER)	$0.40
TRANSPORTATION $800/LOAD WITH 4,500 GALS/TRUCK	$0.18
TOTAL DISPOSAL & TRANS FOR LIQUID INVENTORY	$0.58
DISPOSAL (ACIDIC WASTE IN STORAGE)	$0.40
TRANSPORTATION $800/LOAD WITH 4,500 GALS/TRUCK	$0.18
TOTAL DISPOSAL & TRANS FOR LIQUID INVENTORY	$0.58

SOLIDS DISPOSAL BY LANDFILL	$/LB
TOTAL DISPOSAL & TRANS FOR SOLIDS FOR LANDFILL	$0.27

SOLIDS DISPOSAL BY INCINERATOR	$/LB
DISPOSAL	$0.400
TRANSPORTATION $800/LOAD WITH 35,000 LBS/LOAD	$0.023
TOTAL DISPOSAL & TRANS FOR SOLIDS FOR INCINERATION.	$0.423

ANNULUS FLUID DISPOSAL	$/GAL
DISPOSAL @ 0.71/GAL	$0.71
TRANSPORTATION $800LOAD WITH 4,000 GALS/LOAD	$0.20
TOTAL DISPOSAL & TRANS FOR ANNULUS FLUID	$0.91

SECTION 2

TOTAL FACILITY CLOSURE COST ESTIMATE

CLOSURE AREA	COST ESTIMATE
TREATMENT AND CONTINGENT CLOSURE OF TREATMENT AND STORAGE AREAS (SECTION 3)	$ 1,859,110
CLOSURE OF INJECTION UNITS (SECTION 4)	$ 1,908,118
GENERAL FACILITY AREA CLOSURE (SECTION 5)	$ 55,103
FINAL CLOSURE CERTIFICATION (SECTION 6)	$ 27,815
TOTAL CLOSURE COST ESTIMATE	$ 3,850,146

SECTION 3

TREATMENT AND STORAGE UNITS CLOSURE COST ESTIMATE

INVENTORY REMOVAL:

CLOSURE ITEM	NUMBER OF UNITS GALLONS (Adjusted)	UNIT COSTS $	TOTAL $
TOTAL CAPACITY IN GALLONS LESS 3% WHICH IS ASSUMED TO BE SOLIDS	1,018,500	$0.59*	$598,471

***2013 Original unit cost + 1.7% Inflation Adjustment**

RESIDUAL DISPOSAL:

ASSUMING 3% OF TANK CAPACITY IS SOLIDS. ALL OF THE SOLIDS WILL GO TO A LANDFILL. DENSITY IS 10 LBS/GAL. 1,050,000 GALLONS x .03 = 31,500 GALLONS. 31,500 GALLONS x 10 LBS/GAL = 315,000 LBS.

CLOSURE ITEM	NUMBER OF UNITS POUNDS	UNIT COSTS $	TOTAL $
SOLIDS TO LANDFILL	315,000	$0.275*	$86,496
TOTAL RESIDUAL DISPOSAL			$86,496

***2013 Original unit cost + 1.7% Inflation Adjustment**

SECTION 3 (CONT)

CLEANING, LABOR AND MATERIALS:

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
FAT TANKS	2	$21,000	$42,000
T-TANKS	6	$45,000	$270,000
V-TANKS & SAND INTERCEPTOR VAULTS	4	$9,000	$36,000
FILTER PRESS	1	$9,000	$9,000
LAB TANK	1	$4,600	$4,600
T-TANK SECONDARY CONTAINMENT	1	$17,000	$17,000
FAT A & B CONTAINMENT	1	$7,000	$7,000
FAT 2 CONTAINMENT	1	$7,000	$7,000
FAT 3 CONTAINMENT	1	$7,000	$7,000
FAT 5 CONTAINMENT	1	$7,000	$7,000
FAT 6 CONTAINMENT	1	$7,000	$7,000
PUMP HOUSES	5	$7,000	$35,000
FILTER BUILDING 1 & 2, UNLOADING BUILDING, & RECEIVING BAY	4	$16,412	$65,648
PIPELINE IN FEET	20,000	$10.03	$200,610
EMERGENCY DRAIN TANKS	27	$716	$19,319
TOTAL			$746,657*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 3 (CONT)

RINSE WATER DISPOSAL. FOR TANKS ASSUME 3 RINSES @ 10% OF VOLUME. FOR T-TANK CONTAINMENT, EACH RINSE IS 10% OF LARGEST TANK, 3 RINSES:

CLOSURE ITEM	NUMBER OF UNITS GALLONS	UNIT COSTS $	TOTAL $
TANKS	315,000	$0.46	$144,900
T-TANK CONTAINMENT	60,000	$0.46	$27,600
FAT TANK, 5 AREAS, 10% OF LARGEST TANK (5x10%x11750) (FAT A & B SHARE ONE CONTAINMENT)	17,625	$0.46	$8,108
V-TANK CONTAINMENT, 15% OF LARGEST TANK, INCLUDES SAND INTERCEPTOR VAULT	2,700	$0.46	$1,242
PUMP HOUSES 150 GAL PER RINSE PER PUMPHOUSE	2,250	$0.46	$1,035
LAB TANK 10% OF TANK	750	$0.46	$345
UNLOADING BUILDING	1,500	$0.46	$690
FILTER BUILDING #1	1,500	$0.46	$690
FILTER BUILDING #2	1,500	$0.46	$690
RECEIVING TRUCK BAY	1,500	$0.46	$690
EMERGENCY DRAIN TANK (27) @ 100 GAL/TANK	2,700	$0.46	$1,242
TOTAL			$190,414*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 3 (CONT)

ANALYSIS @ $1,000 PER ANALYSIS:

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
TANKS	13	$1,000	$13,000
SAND INTERCEPTOR VAULTS	4	$1,000	$4,000
BUILDINGS AND BAY	5	$1,000	$5,000
1 FILTER PRESS	1	$1,000	$1,000
CONTAINMENTS	11	$1,000	$1,000
TOTAL			$34,578*

***2013 Original Total + 1.7% Inflation Adjustment**

SUMMARY OF CLOSURE ITEMS		
INVENTORY REMOVAL	$	598,471
RESIDUAL DISPOSAL	$	86,496
CLEANING LABOR AND MATERIALS	$	746,657
RINSE WATER DISPOSAL	$	190,414
ANALYSIS OF SAMPLES	$	34,578
TOTAL OF TREATMENT AND STORAGE CLOSURE COSTS	$	1,656,616

SECTION 3 (CONT)

CONTINGENT CLOSURE OF CONTAINMENTS FOR FATS 2, 3, 5, 6, A AND B:

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
DEMOLISH STRUCTURES AND DISMANTLE TANKS 4 DAYS @ $6,000/DAY	4	$6,000	$24,000
SOIL SAMPLING AND ANALYSIS FROM AREA SURROUNDING CONTAINMENTS, 5 AREAS, 4 SAMPLES PER AREA	20	$1,000	$20,000
BACKFILL, COMPACT AREA, 536 CU.YD. @ $20/CU.YD.	536	$20	$10,720
LINER 2811 SQ.FT. @ $7/SQ.FT.	2811	$7	$19,677
COVER AND REGRADE WITH CLAY FILL, AND 3.0" OF TOPSOIL 210 CU.YD. @ $15/CU.YD.	210	$15	$3,150
SEEDING AREAS 303 SQ. YDS. @ $4/SQ.YD.	303	$4	$1,212
TOTAL CONTINGENT CLOSURE FAT TANKS			$80,098*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 3 (CONT)

CONTINGENT CLOSURE OF V-TANKS:

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
DEMOLISH STRUCTURES AND DISMANTLE TANKS 10 DAYS @ $6,000/DAY	10	$6,000	$60,000
DISPOSAL OF PUMPS & PIPING @ $3,000	1	3,000	$3,000
SOIL SAMPLING AND ANALYSIS FROM AREA SURROUNDING TANK AREA 2 AREAS, 4 SAMPLES/AREA @ $1,000/SAMPLE	8	$1,000	$8,000
BACKFILL, COMPACT AREA, 925 CU.YD. @ $20/CU.YD.	925	$20	$18,500
LINER,60'x60' @ $7/SQ.FT.	3600	$7	$25,200
COVER AND REGRADE WITH CLAY AND TOPSOIL, 3.0" TOPSOIL, 270 CU.YD. @ $15/CU.YD.	270	$15	$4,050
SEEDING AREA 400 SQ.YDS. @ $4/SQ.YD.	400	$4	$1,600
TOTAL FOR CONTINGENT CLOSURE V-TANKS			$122,396*

***2013 Original Total + 1.7% Inflation Adjustment**

SUMMARY OF CONTINGENT CLOSURES		
CONTINGENT CLOSURE: FAT TANKS	$	80,098
CONTINGENT CLOSURE: V-TANKS	$	122,396
TOTAL FOR CONTINGENT CLOSURE	$	202,494
TOTAL FOR TREATMENT AND STORAGE CLOSURE	$	1,656,616
TOTAL COST FOR CLOSURE AND CONTINGENT CLOSURE OF TREATMENT AND STORAGE AREAS.	$	1,859,110

SECTION 4

INJECTION UNIT CLOSURE COST ESTIMATE

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
INJECTION WELLS AND KNOX KERBEL WELL PLUGGING AND ABANDONMENT. RIGS, DRILLING, MITs AND MUD FOR 4 INJECTION WELLS AND ONE DEEP MONITORING WELL @ $353,484/WELL	5	$353,484	$1,767,420
DISPOSAL OF TUBING AND SEALS, 24 TONS @ $0.13/LB	48,000	$0.13	$6,240
ANNULUS FLUID DISPOSAL 8,000 GALLONS @ $0.71GAL	8,000	$0.71	$5,680
PLUGGING AND ABANDONMENT OF LOCKPORT WELL @$42,882	1	$42,882	$42,882
DISPOSAL OF WATER GENERATED FROM ABANDONMENT @ 10,000 GALLON PER WELL, 5 WELLS @ $1.00/GAL	50,000	$1.00	$50,000
WATER GENERATED FROM ABANDONMENT OF LOCKPORT WELL @ 4000 GALLON @ $1.00/GAL	4,000	$1.00	$4,000
TOTAL OF INJECTION UNIT CLOSURE			$1,908,118*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 5

GENERAL FACILITY AREAS CLOSURE COST ESTIMATE

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
DISPOSAL OF LAB CHEMICALS 30-55 GALLON DRUMS @ $0.58/GAL	1,650	$0.58	$953
DECONTAMINATE LAB BUILDING	1	$15,000	$15,000
DECONTAMINATE PERSONNEL CHANGING ROOM	1	$15,000	$15,000
SWEEP ROADS AND PARKING AREA @$800	1	$800	$800
SAMPLE ROADS 10,000 SQ.YDS, 10 SAMPLES @ $1,000/SAMPLE	10	$1,000	$10,000
SAMPLE STAGING AREA, 5 SAMPLES @ $1,000/SAMPLE	5	$1,000	$5,000
SCRUBBER LIQUID AND RINSE DISPOSAL, 5,000 GAL TOTAL @ $0.58	5,000	$0.58	$2,889
SCRUBBER MEDIA DISPOSAL, 2,000 LBS @ $0.27/LB	2,000	$0.27	$540
SAMPLE OF TRUCK SCALES, 4 SAMPLES @$1,000/SAMPLE	4	$1,000	$4,000
TOTAL FOR GENERAL FACILITY AREAS CLOSURE			$55,103*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 6

CLOSURE CERTIFICATION COST ESTIMATE

CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
REGISTERED PROFESSIONAL ENGINEER, 150 HOURS @ $135/HOUR	150	$135	$20,250
PREPARATION OF SURVEY PLAT, 3 DAY @ $1,300/DAY	3	$1,300	$3,900
ADMINISTRATIVE COST 40 HOURS @ $60/HOUR	40	$60	$2,400
CLERICAL COST 20 HOURS @ $40/HOUR	20	$40	$800
TOTAL COST FOR FINAL CLOSURE CERTIFICATION			$27,815*

***2013 Original Total + 1.7% Inflation Adjustment**

SECTION 7

SURFACE IMPOUNDMENT POST- CLOSURE ANNUAL COST ESTIMATE

POST-CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
CARE TAKING, 1 PERSON @ $50,000 TOTAL COMPENSATION	1	$50,850*	$50,850
MAINTENANCE OF COVERS AND GENERAL AREA. MOWING 24.5 ACRES AND MAINTENANCE OF BENCHMARKS	24.5	$763*	$18,687
DITCH MAINTENANCE AND REPAIR OF EROSION DAMAGE	1	$12,204*	$12,204
MAINTENANCE OF FENCING @ 5% EACH YEAR, 11,500 FT	575	$13.22*	$7,602
FERTILIZATION & VEGETATION 24.5 ACRES AT $250/ACRE	24.5	$254*	$6,229
GROUNDWATER SAMPLING, SEMI-ANNUAL EVENT	2	%	%
8 RCRA WELLS INCLUDES 8 TSCA WELLS (+4 QA/QC) SEMIANNUAL ANALYSIS @ $396/SAMPLE	24	$403*	$9,666
ANALYSIS, 2 STREAM SAMPLES SEMI-ANNUALLY	4	$712*	$2,848
LEACHATE SAMPLING AND ANALYSIS, SEMI-ANNUALLY @ $700/SAMPLE	2	$712*	$1,424

***2013 Original unit cost + 1.7% Inflation Adjustment**

POST-CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
CAPILLARY DRAIN SAMPLING AND ANALYSIS, SEMI-ANNUALLY @ $282/SAMPLE	2	$287*	$574
MAINTENANCE OF WELL SYSTEMS	1	$7,628*	$7,628
QUARTERLY WELL INSPECTIONS	4	%	%
DISPOSAL OF LEACHATE @ 1,220 GAL/MONTH @ $0.58/GAL	14,640	$0.59*	$8,602
DISPOSAL OF CAPILLARY DRAIN @ 550 GAL/DAY @ $0.46/GAL	200,750	$0.47*	$93,461
TOTAL ANNUAL POST-CLOSURE COST ESTIMATE			$219,774

***2013 Original unit cost + 1.7% Inflation Adjustment**

SECTION 8

SURFACE IMPOUNDMENT POST-CLOSURE COST ESTIMATE

POST-CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
TOTAL ANNUAL POST-CLOSURE COST FOR 9 YEARS	9	$219,774*	$1,977,968
POST-CLOSURE CERTIFICATION at $27,350	1	$27,815*	$27,815
PLUG AND ABANDON 47 MONITORING WELLS at $1,500/WELL	47	$1,526*	$71,699
TOTAL SURFACE IMPOUNDMENT POST-CLOSURE COST ESTIMATE			$2,077,482

***2013 Original unit cost + 1.7% Inflation Adjustment**

SECTION 9

TANK CONTINGENT POST-CLOSURE COST ESTIMATE

POST-CLOSURE ITEM	NUMBER OF UNITS	UNIT COST $	TOTAL $
INSTALLATION OF 12 MONITORING WELLS @$6,000 PER WELL	12	6,102*	$73,224
GROUNDWATER SAMPLE COLLECTION	21[XX]	$11,187*	$234,927
GROUNDWATER SAMPLE ANALYSIS, 16 SAMPLES, 33 SAMPLING EVENTS	528	$403*	$212,642
CARETAKING, 1 PERSON @ $2,060 PER YEAR FOR 21 YEARS** (INCLUDES INSPECTIONS OF COVERS, WELLS, ETC.)	21[XX]	$3,051*	$64,071
MAINTENANCE OF COVERS, 1 ACRE TOTAL AT $750/ACRE INCLUDING MOWING, BENCHMARKS FOR 30 YEARS	1 ACRE FOR 30 YEARS	$763*	$22,883
MAINTENANCE OF FENCING AND GATES AT 5% EACH YEAR, 575 FT, 21 YEARS**	575 FT FOR 21 YEARS[XX]	$13.22*	$159,644
FERTILIZATION & VEGETATION, 1 ACRE AT $250/ACRE FOR 30 YEARS	1 ACRE FOR 30 YEARS	$254*	$7,628
MAINTENANCE OF WELL SYSTEMS, @ $7,500/ YEAR FOR 21 YEARS**	21[XX]	$7,628*	$160,178
POST-CLOSURE CERTIFICATION @ $15,625	1	$15,891*	$15,891
PLUG AND ABANDON 12 MONITORING WELLS @ $1,500/WELL	12	$1,526*	$18,306
TOTAL TANK CONTINGENT POST-CLOSURE COST ESTIMATE			$969,127

***2013 Original unit cost + 1.7% Inflation Adjustment**

[XX] This number is the number of events that will occur after the post-closure of the surface impoundments is complete. While the surface impoundment post closure is active, these items will be performed by caretaker for that post closure.

SECTION 10

INJECTION WELLS POST CLOSURE COST ESTIMATE

POST CLOSURE ITEM	NUMBER OF UNITS	UNIT COSTS $	TOTAL $
SAMPLING AND ANALYSIS OF DEEP MONITORING WELL FOR 2.4 YEARS AFTER CLOSURE (ASSUME 3 SAMPLING EVENTS) KNOX KERBEL WELL	3	$18,072*	$54,216
SAMPLING AND ANALYSIS OF LOCKPORT WELL - 3 SAMPLING EVENTS	3	$4,678*	$14,035
TOTAL INJECTION WELLS POST CLOSURE COST ESTIMATE			$68,251

*2013 Original unit cost + 1.7% Inflation Adjustment

SECTION 11

TOTAL POST- CLOSURE COST ESTIMATE

POST-CLOSURE AREA	COST ESTIMATE
SURFACE IMPOUNDMENT (SECTIONS 7 AND 8)	$2,077,482
TANK CONTINGENT POST CLOSURE (SECTION 9)	$969,127
INJECTION WELLS POST CLOSURE (SECTION 10)	$68,251
TOTAL POST-CLOSURE COST ESTIMATE	$3,114,859

NATIONAL GUARANTY INSURANCE COMPANY OF VERMONT

100 BANK STREET, SUITE 610• BURLINGTON, VT 05401

CERTIFICATE OF INSURANCE FOR CLOSURE OR POST-CLOSURE CARE

Name and Address of Insurer (hereinafter called the "Insurer"):

NATIONAL GUARANTY INSURANCE COMPANY OF VERMONT

100 Bank Street, Suite 610, Burlington, Vermont 05401

Name and Address of Insured (hereinafter called the "Insured"):

VICKERY ENVIRONMENTAL, INC.

3956 State Route 412, Vickery, Ohio 43464

Facilities Covered:

EPA ID Number: OHD020273819

Ohio Permit Number: OHD020273819

Name: VICKERY ENVIRONMENTAL, INC.

Address: 3956 State Route 412

Vickery, Ohio 43464

Face Amount: $6,965,005.00

Closure: A. $3,850,146.00

Post-Closure B. $3,114,859.00

Policy Number: CPCH92-0003

Effective Date: March 1, 1992 (Policy period 1/7/2014 – 1/7/2015)

The Insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for closure and post-closure care for the facility identified above. The Insurer further warrants that such policy conforms in all respects with the requirements of paragraph (E) of rules 3745-55-43 and 3745-55-45, and Paragraph (D) of rules 3745-66-43 and 3754-66-45 of the Administrative Code, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

Whenever requested by the director of the Ohio Environmental Protection Agency, the Insurer agrees to furnish to the director a duplicate original of the policy listed above, including all endorsements thereon.

I hereby certify that the wording of this certificate is identical to the wording specified in paragraph (E) of rule 3745-55-51 of the Administrative Code as such regulations were constituted on the date shown immediately below.

Donna L. Meals

Authorized Signature for Insurer

December 2, 2013

Date

Donna L. Meals

Name of person signing

Vice President and Secretary

Title of person signing

Laura Ibbleth

Witness

HAZARDOUS WASTE FACILITY CERTIFICATE OF LIABILITY INSURANCE

1. AIG SPECIALTY INSURANCE COMPANY, (the "Insurer"), of 175 Water Street, New York, New York, 10038 hereby certifies that it has issued liability insurance covering bodily injury and property damage to Waste Management, Inc., (the "Insured") of 1001 Fannin, Suite 4000, Houston, Texas 77002 in connection with the insured's obligation to demonstrate financial responsibility under rules 3745-55-47 and or 3745-66-47 of the Administrative Code. The coverage applies at EPA ID Number OHD020273819, Vickery Environmental, Inc., Ohio Permit #03-72-0191, 3956 State Route 412, Vickery, Ohio 43464 for nonsudden accidental occurrences. The limits of liability are $3,000,000 each occurrence and $6,000,000 annual aggregate, exclusive of legal defense costs. The coverage is provided under policy number PLS 14240854 issued on January 1, 2014. The effective date of said policy is January 1, 2014.

2. The Insurer further certifies the following with respect to the insurance described in Paragraph 1:

   (a) Bankruptcy or insolvency of the insured shall not relieve the Insurer of its obligations under the policy.

   (b) The Insurer is liable for the payment of amounts within any deductible applicable to the policy, with a right of reimbursement by the insured for any such payment made by the Insurer. This provision does not apply with respect to that amount of any deductible for which coverage is demonstrated as specified in paragraph (F) of rule 3745-55-47 or paragraph (F) of rule 3745-66-47 of the Administrative Code.

   (c) Whenever requested by the director of the Ohio Environmental Protection Agency, the Insurer agrees to furnish to the director a signed duplicate original of the policy and all endorsements.

   (d) Cancellation of the insurance, whether by the Insurer, the insured, a parent corporation providing insurance coverage for its subsidiary, or by a firm having an insurable interest in and obtaining liability insurance on behalf of the owner or operator of the hazardous waste management facility, will be effective only upon written notice and only after the expiration of sixty days after a copy of such written notice is received by the director.

   (e) Any other termination of the insurance will be effective only upon written notice and only after the expiration of thirty days after a copy of such written notice is received by the director.

I hereby certify that the wording of this instrument is identical to the wording specified in paragraph (J) of 3745-55-51 of the Administrative Code as such regulation was constituted on the date first above written, and that the Insurer is licensed to transact the business of insurance, or eligible to provide insurance as an excess or surplus lines insurer, in one or more States.

Ruth Calabrese
Vice President – Environmental
Authorized Representative of
AIG Specialty Insurance Company
2929 Allen Parkway, Suite 1300
Houston, Texas 77019-2128
Date Issued: January 1, 2014

CERTIFICATE ISSUED TO:
Director
Ohio Environmental Protection Agency
Div. of Hazardous Waste Mgmt.
122 South Front Street
Columbus, OH 43216-0149

HAZARDOUS WASTE FACILITY CERTIFICATE OF LIABILITY INSURANCE

1. AIG SPECIALTY INSURANCE COMPANY, (the "Insurer"), of 175 Water Street, New York, New York 10038 hereby certifies that it has issued liability insurance covering bodily injury and property damage to Waste Management, Inc., (the "Insured") of 1001 Fannin, Suite 4000, Houston, Texas 77002 in connection with the Insured's obligation to demonstrate financial responsibility under rules 3745-55-47 and or 3745-66-47 of the Administrative Code. The coverage applies at EPA ID Number OHD020273819, Vickery Environmental, Inc., Ohio Permit #03-72-0191, 3956 State Route 412, Vickery, Ohio 43464 for sudden accidental occurrences. The limits of liability are $1,000,000 each occurrence and $2,000,000 annual aggregate, exclusive of legal defense costs. The coverage is provided under policy number PLS 14240854 issued on January 1, 2014. The effective date of said policy is January 1, 2014.

2. The Insurer further certifies the following with respect to the insurance described in Paragraph 1:.

   (a) Bankruptcy or insolvency of the insured shall not relieve the Insurer of its obligations under the policy.

   (b) The Insurer is liable for the payment of amounts within any deductible applicable to the policy, with a right of reimbursement by the insured for any such payment made by the Insurer. This provision does not apply with respect to that amount of any deductible for which coverage is demonstrated as specified in paragraph (F) of rule 3745-55-47 or paragraph (F) of rule 3745-66-47 of the Administrative Code.

   (c) Whenever requested by the director of the Ohio Environmental Protection Agency, the Insurer agrees to furnish to the director a signed duplicate original of the policy and all endorsements.

   (d) Cancellation of the insurance, whether by the Insurer, the insured, a parent corporation providing insurance coverage for its subsidiary, or by a firm having an insurable interest in and obtaining liability insurance on behalf of the owner or operator of the hazardous waste management facility, will be effective only upon written notice and only after the expiration of sixty days after a copy of such written notice is received by the director.

   (e) Any other termination of the insurance will be effective only upon written notice and only after the expiration of thirty days after a copy of such written notice is received by the director.

I hereby certify that the wording of this instrument is identical to the wording specified in paragraph (J) of 3745-55-51 of the Administrative Code as such regulation was constituted on the date first above written, and that the Insurer is licensed to transact the business of insurance, or eligible to provide insurance as an excess or surplus lines insurer, in one or more States.

Ruth Calabrese
Vice President – Environmental
Authorized Representative of
AIG Specialty Insurance Company
2929 Allen Parkway, Suite 1300
Houston, Texas 77019-2128
Date Issued: January 1, 2014

CERTIFICATE ISSUED TO:
Director
Ohio Environmental Protection Agency
Div. of Hazardous Waste Mgmt.
122 South Front Street
Columbus, OH 43216-0149

ATTACHMENT B

INJECTION ZONE INFORMATION

This attachment contains a summary of the Injection Zone data. The information was submitted as a part of VEI's permit to operate renewal application and is located in ATTACHMENT F of the application.

10.0 CHARACTERISTICS OF THE INJECTION ZONE

10.1 Introduction

The criteria for siting of hazardous waste injection wells codified in 40 CFR, Part 146.62 (C)(1), requires that the injection zone has sufficient permeability, porosity, thickness and areal extent to prevent migration of fluids into USDWs.

The injection zone is defined in 40 CFR, Part 146.3 as a geological formation, group of formations, or part of a formation receiving fluids through a well. The injection of hazardous waste can only take place below the lowermost formation containing within 1/4 mile of the well bore, a USDW. Vickery has separated the injection zone into an injection interval, into which actual emplacement of waste fluid occurs, and a containment interval which includes the layers above the injection interval where vertical fluid movement will be contained.

The following subsections describe the injection intervals suitability for injection of hazardous waste and the containment intervals properties which make it capable of limiting fluid movement out of the injection zone.

10.2 Injection Interval

10.2.1 Lithology, Reservoir Thickness

The permitted injection interval for the Vickery waste disposal wells is the Mt. Simon Formation, a Cambrian age sandstone. The Mt. Simon averages slightly over 121 feet in thickness, with minimum and maximum recorded thickness of 84 and 147 feet respectively from wells within the AOR. The formation is composed of moderately to well sorted, very fine to coarse grained sandstones. Quartz and K-feldspar are the primary framework grains. These sandstones contain low quantities of detrital clay, but authigenic grain coating chlorite is fairly common. Dolomite cement and interbedded dolomite zones are sporadically distributed throughout the formation. Detailed data concerning lithology of the injection interval **is found in Attachment C.**

10.2.2 Porosity and Permeability

Porosity is a measurement of how much void space is available for fluids to occupy within a volume of rock, generally expressed as a percentage. Permeability is a measurement of the capacity of a material to transmit a fluid under the influence of a pressure differential. A standard unit of permeability measurement is the darcy, which

TABLE 10-1

MT. SIMON POROSITY AND PERMEABILITY TO AIR

		Total Mt. Simon Thickness	Top 30 Feet
WELL #1*	N	89	21*
	K_h (md)	36.09	24.26
	ϕ_h (%)	15.06	14.53
	N	89	21*
	K_v (md)	.0086	.29
	ϕ_v (%)	NA	NA
WELL #4	N	93	30
	K_h (md)	62.08	98.06
	ϕ_h (%)	12.65	14.97
WELL #5	N	132	30
	K_h (md)	32.01	60.98
	ϕ_h (%)	13.63	13.60
3 WELLS OVERAGED	N	314	81
	K_h (md)	42.07	65.19
	ϕ_h (%)	13.75	14.35
	N**	89	21*
	K_v (md)	.0086	.29
	ϕ_v (%)	NA	NA

* Upper 9 ft of Mt. Simon was not cored
** Only from #1 Well
N Number of samples
K_h Arithmetic mean
K_v Harmonic mean
ϕ_h Arithmetic mean

is defined as the flow of one cubic centimeter per second of a fluid with viscosity of one centipoise through a porous medium having a cross sectional area of one square centimeter and length one centimeter, under a pressure differential of one atmosphere. As a practical matter, measurements are usually expressed in millidarcies (md), where one millidarcy = .001 darcy.

There have been many different studies performed on the Vickery wells over a period of more that 20 years. The following is a summary of porosity and permeability data. The reader is referred to the original petition document, and to Appendix A of this document which specifically summarizes flow through testing and petrographic tests that were completed after the original petition was submitted. The full report of these tests were previously submitted to the USEPA and ODNR.

Porosity and permeability of the Mt. Simon at Vickery were obtained through plug and whole core analysis of cores from Disposal Wells Nos. 1, 4 and 5. The arithmetic mean horizontal permeability to air in the 3 cored wells was 42.1 md (314 samples), and ranged from <.0001 md to 730 md. One sample in the No. 5 well tested for horizontal permeability at 50 md in one direction and 3037 md at 90 degrees to that direction. This extremely high value is believed to have been caused by induced fracturing of the sample, and is not reliable. The harmonic mean vertical permeability to air as measured in the No. 1 well was .0086 md, and ranged from <.0001 md to 163 md, (89 samples). Porosity in the three cored wells averaged 13.75 percent, and ranged from 2.9 to 22.8 percent, (314 samples).

Within the top 30 feet of the Mt. Simon in the three cored wells, horizontal permeability to air averaged 65.2 md and ranged from <.1 md to 730 md. Porosity averaged 14.4 percent and ranged from 2.9 to 22.8 percent. The significance of this above average permeability and porosity will be explored in greater detail later in this section, and in the modeling section. Table 10-1 summarizes the porosity and permeability to air data for the Mt. Simon.

Figure 10-1 represents the horizontal permeabilities from Disposal Wells Nos. 1, 4 and 5 as measured in cores at one foot intervals, and demonstrates the lateral continuity of the permeability zones across the Vickery site.

Figures 10-2, 10-3 and 10-4 compare core measured permeabilities to the bulk density logs through the corresponding intervals. There is a good to fair correlation of the

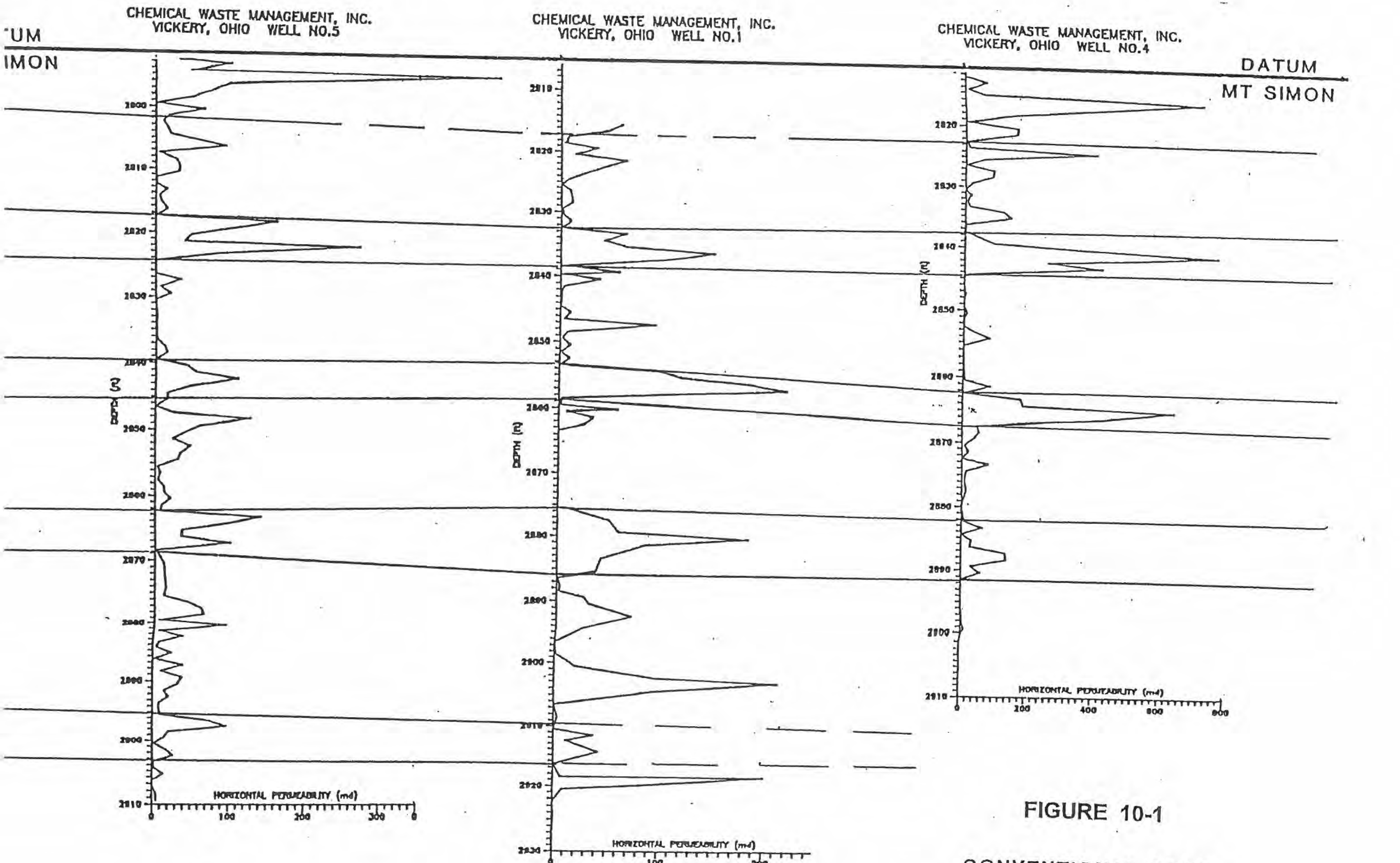
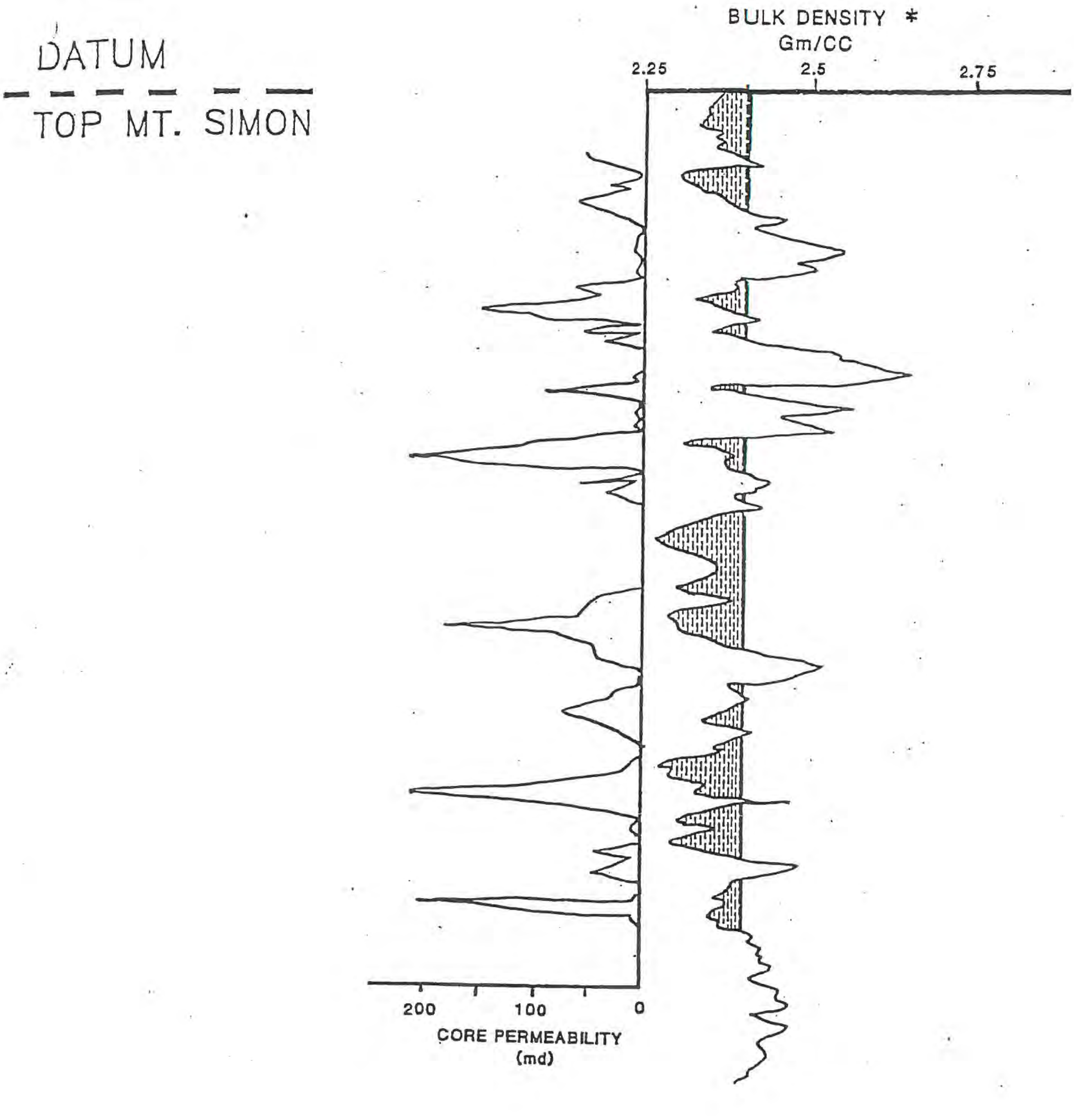


FIGURE 10-1

CONVENTIONAL CORE

PERMEABILTY CORRELATION

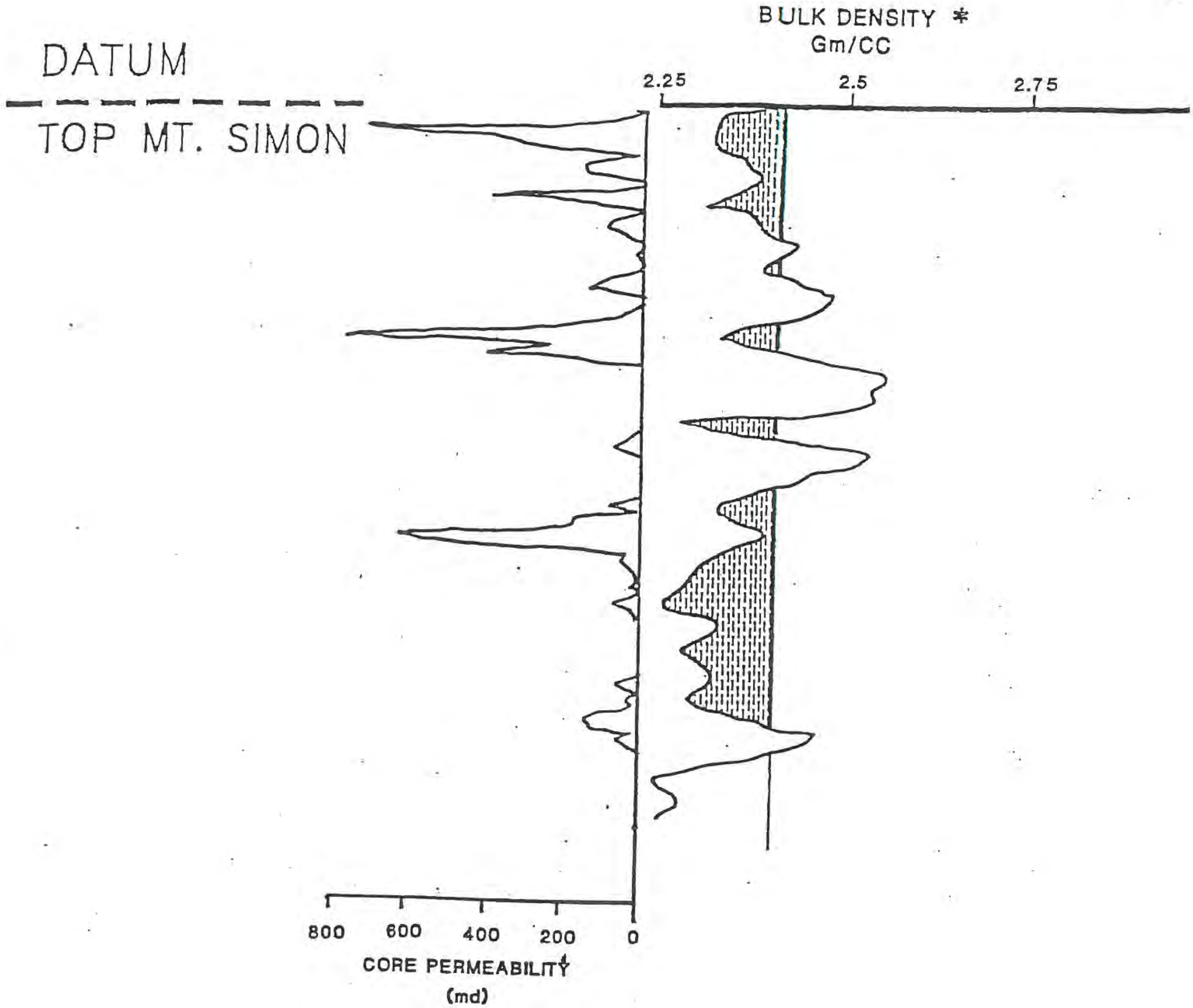


20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM SCHLUMBERGER COMPENSATED FORMATION DENSITY LOG RUN 3/17/72.

DISPOSAL WELL NO. 1
CORE PERMEABILITY VS.
BULK DENSITY

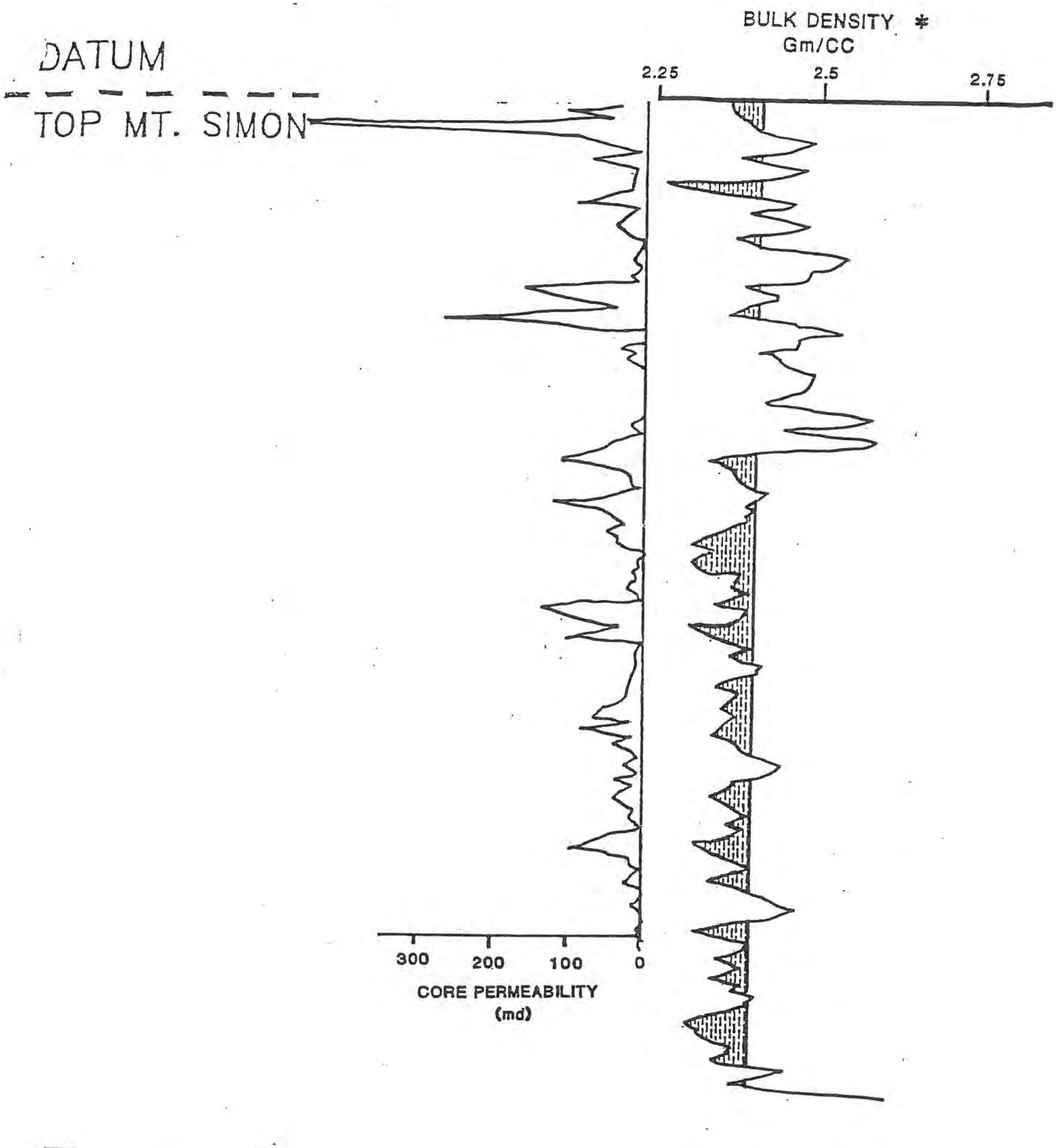


20'

ZONES WITH POROSITY > 15%, ASSUMING MATRIX DENSITY = 2.68 GM/CC.

* FROM BIRDWELL DENSITY BOREHOLE COMPENSATED LOG RUN 7/29/76

DISPOSAL WELL NO. 4
CORE PERMEABILITY VS.
BULK DENSITY



* FROM SCHLUMBERGER COMPENSATED NEUTRON-FORMATION DENSITY LOG RUN

DISPOSAL WELL NO. 5
CORE PERMEABILITY VS.
BULK DENSITY

porosity zones represented on the density logs with the permeabilities obtained from core measurements.

The effect of relatively low relief Precambrian topography on the containment capabilities of the injection zone is expected to be negligible. It will be demonstrated later in this section that most of the injected waste goes into the uppermost portions of the Mt. Simon. These zones are continuous across the Vickery site and are not affected by Precambrian topographic relief.

Porosity vs permeability (>.1 md) cross plots for Disposal Wells Nos. 1, 4 and 5 are shown in Figures 10-6, 10-7 and 10-8. Combined data from all three wells are represented in Figure 10-9. There is generally fair correlation between porosity and permeability within the Mt. Simon. Data scatter is thought to be largely due to the presence of variable amounts of quartz and dolomite cement, and argillaceous materials.

10.2.2.1 Porosity Development and Diagenesis

The Mt. Simon consists largely of sandstones with high textural variability and dolomite beds which appear to have formed by diagenetic replacement. Sandstones with the highest porosity development are generally well sorted, clay-poor, fine to medium grained sand that are relatively free of pore filling dolomite cement.

The diagenetic alteration of these sandstones began with moderate burial compaction which was then succeeded by the formation of grain-coating chlorite, quartz overgrowth cements (followed closely by K-feldspar overgrowth cement), and followed in turn by the

FIGURE 10-6

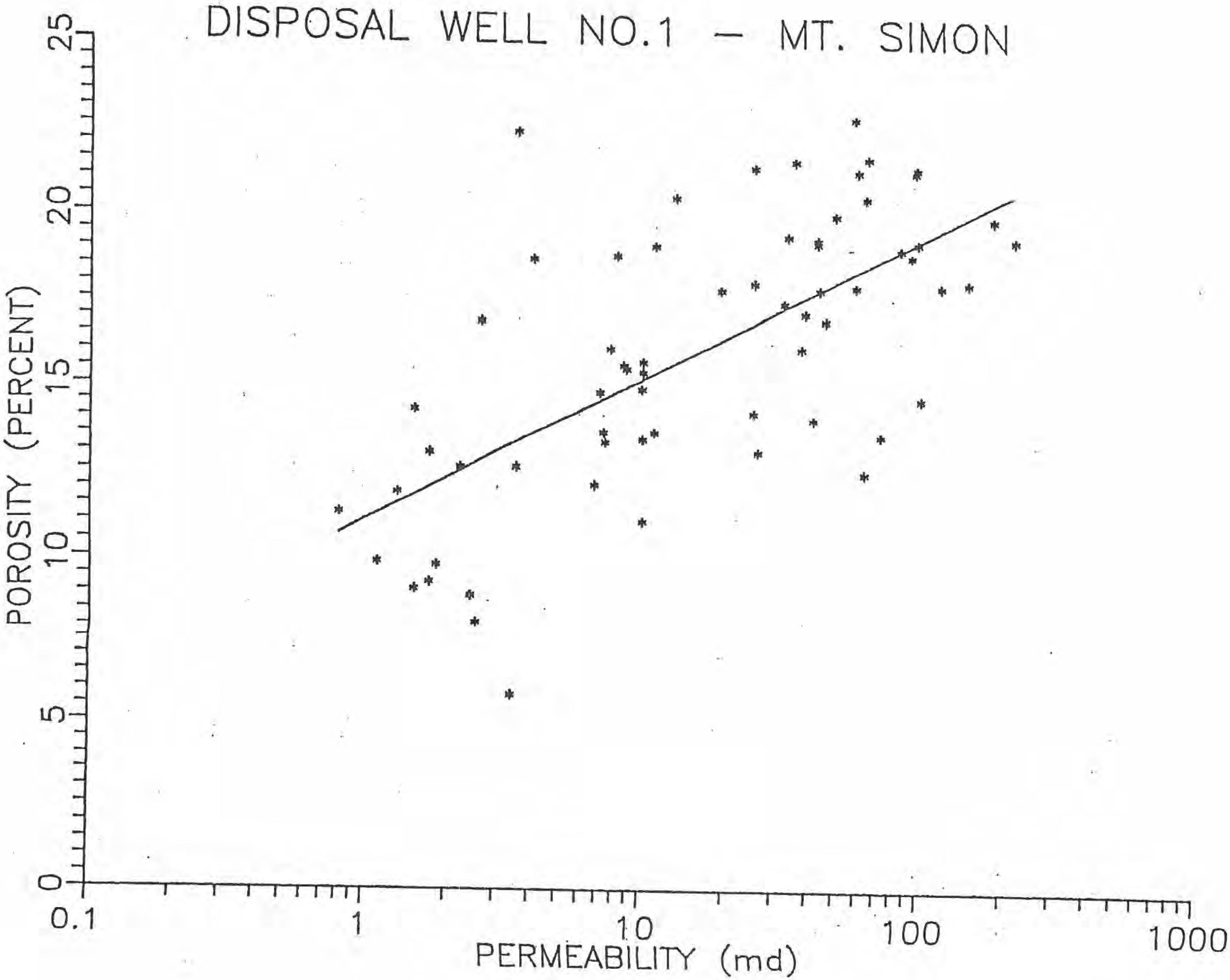
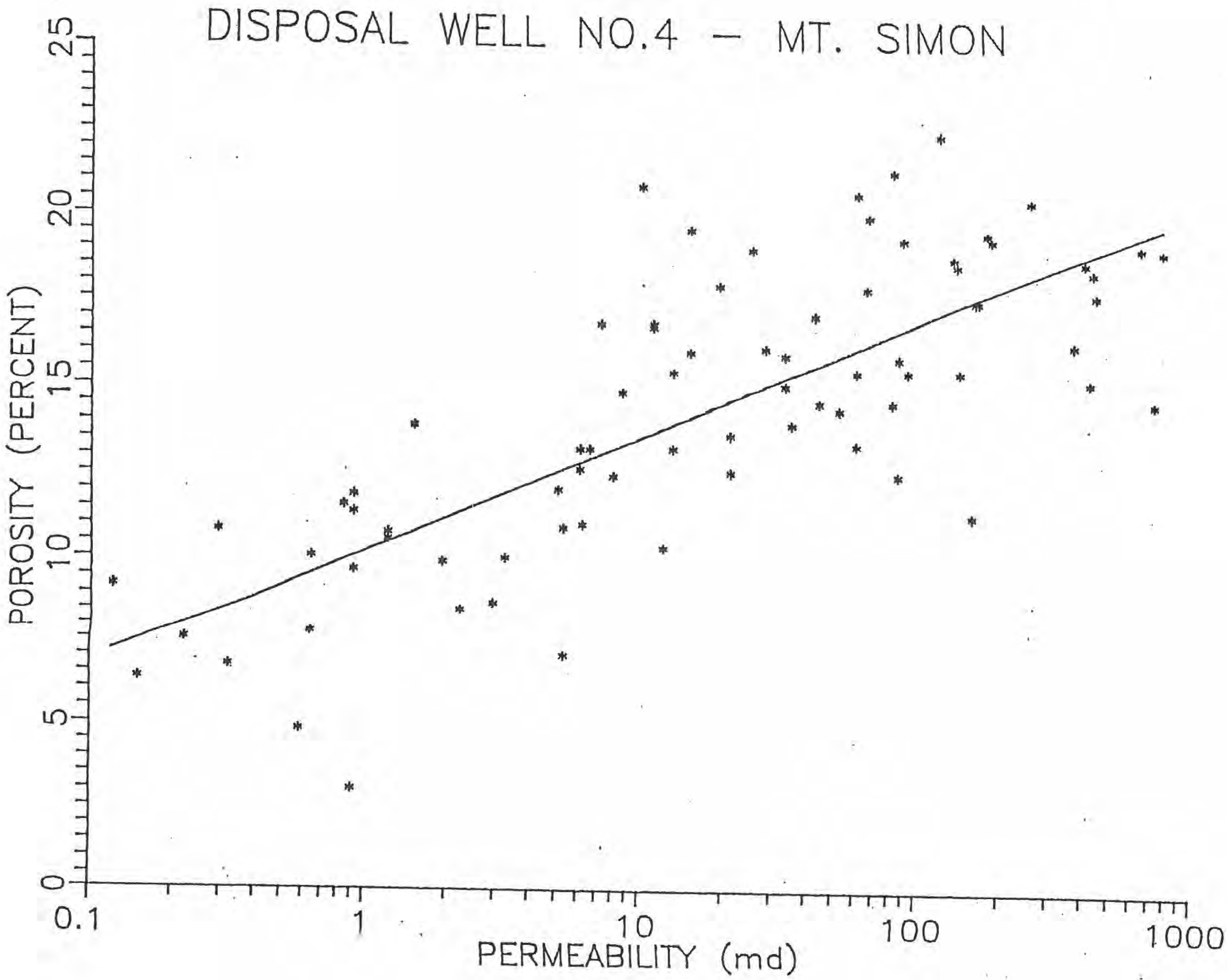

DISPOSAL WELL NO.1 — MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABILITY (md)

FIGURE 10-7



DISPOSAL WELL NO.4 — MT. SIMON
POROSITY (PERCENT)
0
5
10
15
20
25
0.1
1
10
100
1000
PERMEABILITY (md)

FIGURE 10-8

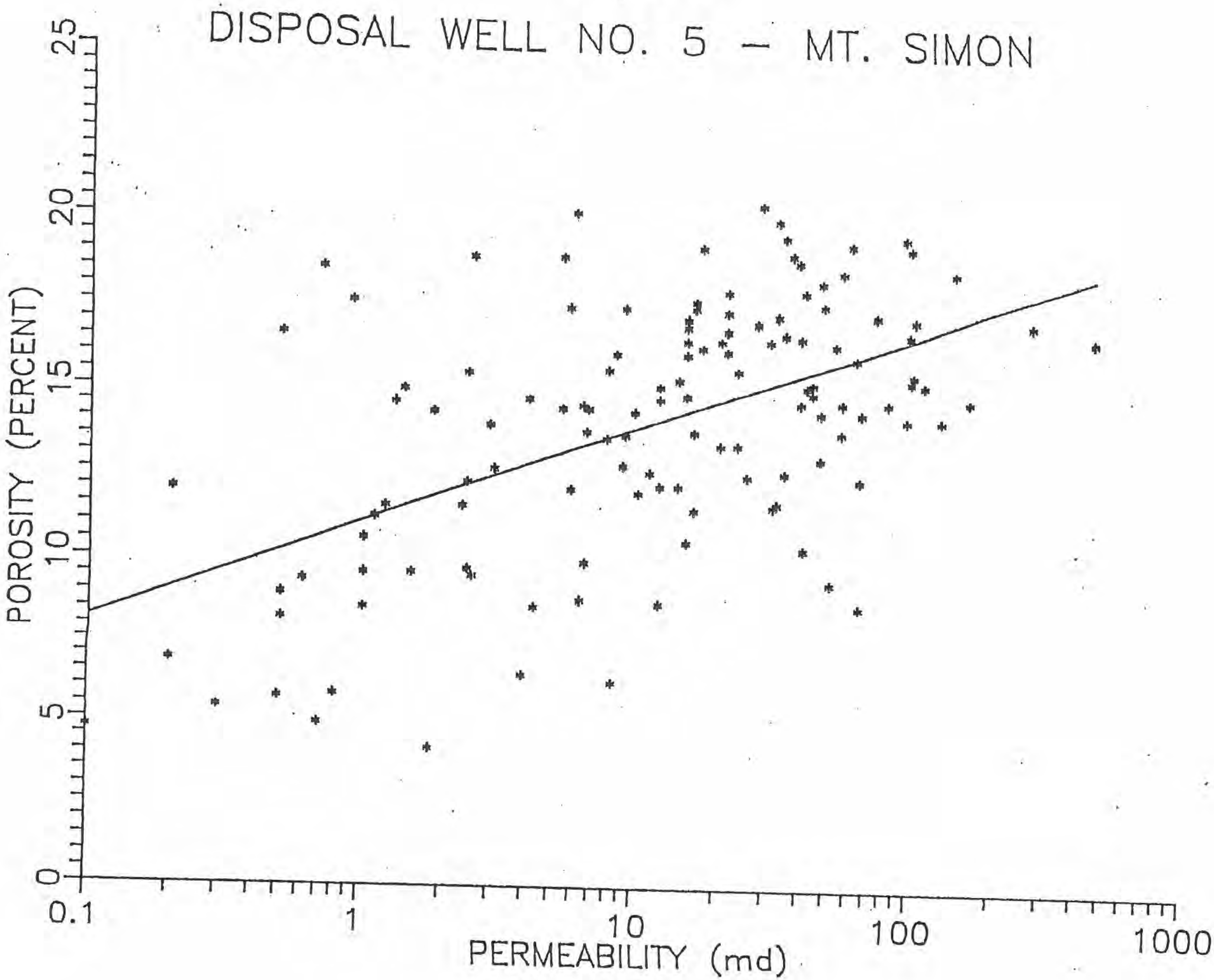
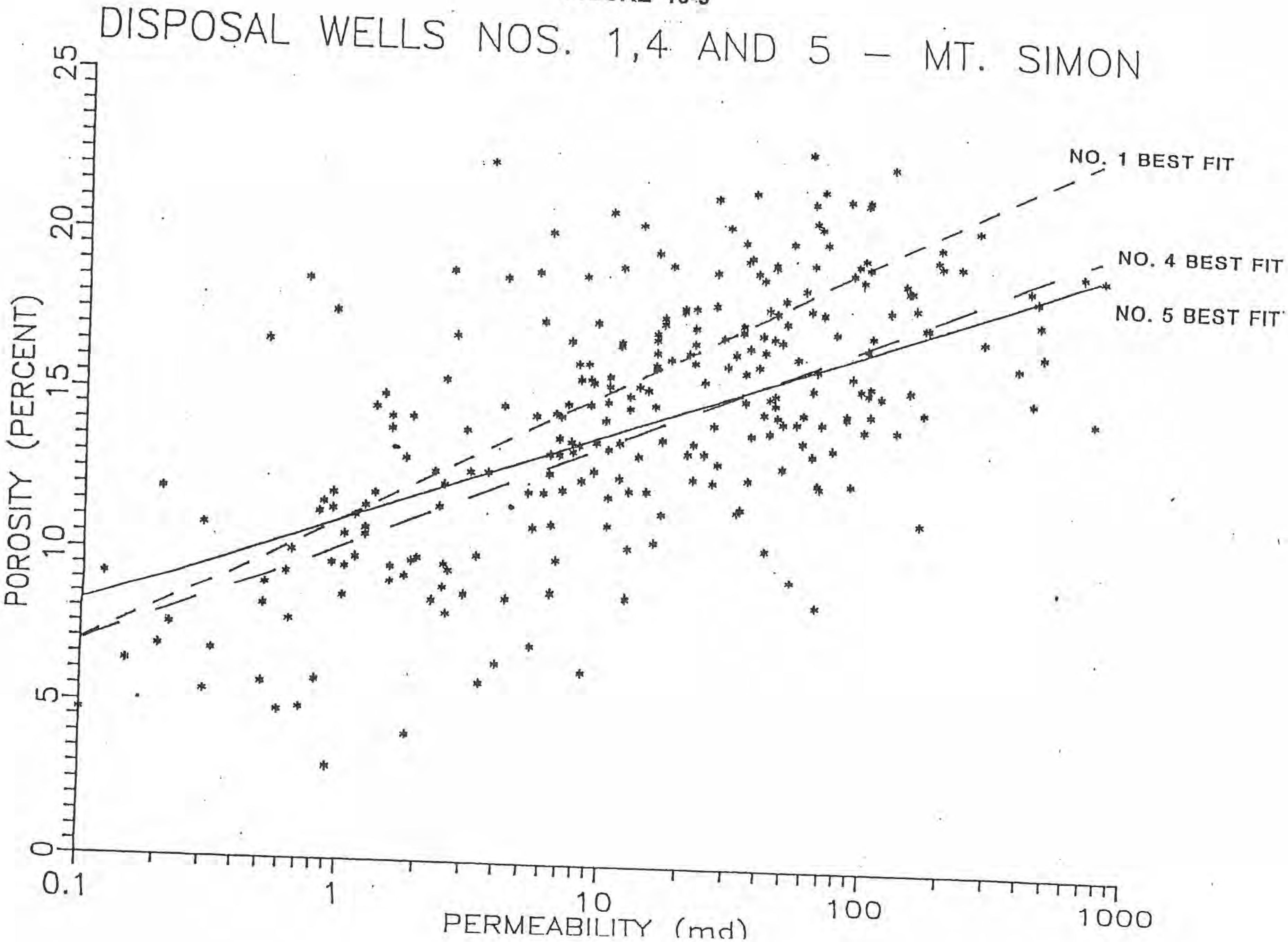

DISPOSAL WELL NO. 5 — MT. SIMON
POROSITY (PERCENT)
PERMEABILITY (md)
0
5
10
15
20
25
0.1
1
10
100
1000

FIGURE 10-9



DISPOSAL WELLS NOS. 1,4 AND 5 — MT. SIMON
NO. 1 BEST FIT
NO. 4 BEST FIT
NO. 5 BEST FIT
POROSITY (PERCENT)
0
5
10
15
20
25
PERMEABILITY (md)
0.1
1
10
100
1000

dissolution of unstable detrital grains (largely feldspar). Dissolution porosity was followed by a second phase of quartz cementation, the development of authigenic illite (which occurs in small amounts), and rare pyrite cement. An earlier, sometimes extensive episode of dolomite cementation, was recognized in some beds, especially beds rich in carbonate particles (i.e. ooids, peloids). This episode appears to have occurred shortly after the development of K-feldspar overgrowth and immediately preceding secondary grain dissolution. This is suggested by the fact that dolomite cement often appears in thin section to envelope quartz and feldspar overgrowth, yet dolomite cement is almost never found within secondary dissolution pores. This phase of cementation reduces visible porosity to very low levels within some beds.

Visible porosity in thin section samples of the Mt. Simon ranges from 0.5 - 23.0%. In general, dolomite cemented sandstones display visible porosity of less than 8%, whereas clean, well sorted fine to medium-grained sandstones display much higher visible porosity (10%). In these cleaner sandstones, intergranular pores are evenly distributed, and secondary pores (moldic and intragranular pores) are present in high proportions. Measured permeability values typically exceed 50 md in such sandstones. Some sandstone beds within the Mt. Simon (especially the lower one-third of the interval) contain discontinuous clay-rich laminations. Although such sandstones contain moderate visible porosity (5-12%) the distribution of pores is often uneven. Measured permeability is often less than 5 md.

Although the Mt. Simon is variable in terms of texture and cement distribution, clean, well sorted sandstones with moderately high permeability characterize most of the Mt Simon sandstone.

10.2.2.2 Radioactive Tracer Profiles

In Section 10.2.2 of this document it was noted that the upper 30 feet of the Mt. Simon contains porosity and permeability which are above average for the formation. It appears that this upper portion of the formation accepts the bulk of the injected fluid.

Radioactive tracer profile surveys, utilizing Iodine 131 as a source, were previously run in each of the active disposal wells. Interpretation of the surveys has indicated that from 68 percent to over 90 percent of the injected fluid enters the Mt. Simon within the upper 30 feet of the formation.

10.2.3 Formation Fracture Gradient

The "strength" of a rock is a term used in experimental structural geology that is only meaningful when the environmental conditions the rock is subjected to are specified. In general, the strength of a rock is its ability to withstand differential stress to the point at which it undergoes brittle failure. The environmental factors affecting a rock's strength include, but are not limited to, mineralogy, grain size, porosity, confining pressure, pore fluid pressure, temperature, presence of reacting solutions and duration of stress. The combined influence of these factors control the point at which a rock will undergo brittle failure. Certain rock types may behave differently under differing sets of environmental conditions. The strength of a rock can be measured under varied environmental conditions via laboratory methods.

When hydraulically fracturing a well, an array of physical events are interacting within the well/formation system. The fluid is moving down the wellbore with momentum influenced by pump horsepower, rate, fluid density, fluid viscosity, wellbore mechanics, and pipe friction. The resultant hydraulic force impacts the formation with applied stress of sufficient magnitude to cause the rock to fracture. A fracture occurs in the formation when hydraulic pressure overcomes the combined resistances of the tensile strength of the formation and the compressional stress caused by the overburden stress gradient.

The surface pressure observed at the moment the pumping operations are suddenly discontinued is called the instantaneous shut-in pressure, ISIP. This represents the minimum pressure required to open a hydraulically created fracture. The ISIP may be related to an equivalent bottomhole pressure, the bottomhole treating pressure, by using the following equation:

BHTP = ISIP + Ph where

BHTP	=	Bottomhole Treating Pressure (psi)
ISIP	=	Instantaneous Shut-in Pressure (psi)
Ph	=	Hydrostatic Pressure (psi).

Once the Bottomhole Treating Pressure is known, then the fracture gradient can be determined from the following equation:

Fracture Gradient = BHTP / Depth.

A proposed fracture stimulation was attempted on the Vickery Well No. 5 on October 13, 1982. The fracture stimulation ended when the well "screened out"; that is, the wellhead pressure during the treatment reached the maximum allowable pressure (determined from the strength of the tubulars in the well) before the wellbore could be flushed of the sand ladened fluid. With the wellbore filled with sand ladened fluid, an instantaneous shut-in pressure representative of the minimum pressure required to open the fracture cannot be obtained because the fracture has already closed. Therefore it follows that under these conditions the fracture gradient cannot be obtained.

The fact that a representative ISIP cannot be obtained is substantiated by the field data on Well No. 5. The data shows that the field service operator did not record ISIP in any of three places where ISIP is normally recorded on the field record. The events that occurred can be determined from the field strip chart and will be discussed chronologically. The fracing procedure was progressing normally until 10:42 AM with Dowell pumping sand laden fluid with 7 lb/gal sand at a rate of 15 bpm at 1900 psi. Then at 10:44 AM the sand was increased from 7 lb/gal to 9 lb/gal. Immediately, pressure started building and by 10:48 AM pressure was at 3300 psi. This indicated screen out and fracture closure. The pumps were shut down for a minute while pressure fell to 1125 psi and then to 650 psi. A brief attempt to flush out the sand by pumping the pumps resulted in another 3300 psi pressure peak at 10:48 AM which again indicated screen out and fracture closure. Dowell then ceased operations and rigged down. All test data was submitted to the OEPA in the Well 5 Completion Report.

In January, 1984, Well No. 4 was notched from 2904 to 2896 ft using a Hydrajet tool. After the notches were made a radioactive tracer was released at 1900 ft (inside the 5 inch casing) and pumped down the well. The radioactive tracer log indicated that most of the fluid was entering the notched portion of the wellbore. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. A final instantaneous shut-in pressure of 970 psi was recorded during the pump test. The BHTP can be determined from the instantaneous shut-in pressure as follows:

$$BHTP = ISIP + Ph$$

In this case Ph is equal to the hydrostatic pressure of a 2819 ft column (depth below ground to casing seat) of 10 lb/gal brine (type of fluid in the wellbore when shut-in), which is 1464.5 psi. Therefore, the BHTP = 970 + 1464.5 = 2432.5 psi which is equivalent to a fracture gradient of 0.86 psi/ft (2434.5 psi/2819 ft).

Following the pump test it was decided to Hydrajet the entire open-hole interval and not to fracture stimulate the well. All test data was submitted to the OEPA in the Well 4 Completion Report.

In June, 1984, Well No. 2 was notched from 2930 to 2920 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test never clearly indicated a breakdown pressure; therefore, Halliburton's engineers felt the test was inconclusive as to whether or not a fracture had been initiated. Instantaneous shut-in pressures of 730 to 740 psi were recorded during the pump test. Based on these pressures, a 10 lb/gal displacement fluid, and a casing depth of 2791 ft., BHTPs of 2180 psi and 2190 psi can be calculated using the method described earlier. Those values give a frac gradient of 0.781 and 0.785 psi/ft. Following the pump test Well No. 2 was fracture stimulated. At the end of the fracture treatment an ISIP of 830 psi was recorded. Previously it was thought that the displacement fluid was 2% potassium chloride. However, upon closer examination of the well records it was determined that the 2% potassium chloride solution was followed by a 10 lb/gal sodium chloride brine prior to shutting down the pumps. The hydrostatic head of the 10 lb/gal brine is calculated as follows:

Ph = 1.2 spec. gravity x 0.433 psi/ft x 2791 ft. = 1450 psi.

Using observed ISIP of 830 psi and Ph of 1450 psi yields:

BHTP = ISIP + Ph = 830 + 1450 = 2280 psi

which is a 0.82 psi/ft fracture gradient. All test data was submitted to the OEPA in the Well 2 Completion Report.

In August 1984, Well No. 6 was notched from 2890 to 2880 ft using a Hydrajet tool. Next a pump test was performed to establish the breakdown pressure and fracture gradient. The pump test indicated the breakdown pressure was approximately 1600 psi. An instantaneous shut-in pressure of 990 psi was recorded at the end of the pump test. Based on this pressure, a 9.9 lb/gal displace-ment fluid, and a casing depth of 2809 ft, BHTP of 2345 psi and a frac gradient of 0.83 can be calculated.

During the same test, the initial breakdown pressure was calculated to be 3069 psi at 2880 ft or 1.07 psi/ft using the 1600 psi surface pressure recorded. All test data was submitted to OEPA, April 4, 1985 in the Well No. 6 Completion Report.

In August, 1994, Vickery performed additional evaluations on the formation fracture gradients. A report dated August 4, 1994 was submitted to Ohio EPA entitled "Fracture Gradient Project." This report concludes that data demonstrates that the current maximum surface injection pressure of 785 psig *(at that time)*, which is based on a fracture gradient of 0.75 psi/ft, will not initiate new fractures or propagate existing fractures in the injection zone.

10.2.3.1 Uncertainty in Determination of Fracture Gradients

Uncertainty in the determination of fracture gradients can come from two sources ISIP, and Ph, as determined by the following equation:

$$BHTP = ISIP + Ph$$

This discussion will quantify the expected uncertainty in the determination of BHTP and therefore fracture gradients.

Hydrostatic head, Ph is calculated by the equation:

$$Ph = \text{Spec. Gravity} \times 0.433 \text{ psi/ft} \times \text{Depth}.$$

Field service supervisors generally agree that field procedures are well established to prevent significant errors in fluid density. Most agree that it is rare for fluid density to vary by more than 0.2 lb/gal from specified density. To get some idea of the magnitude of uncertainty that might occur from the maximum 0.2 lb/gal error, the parameters of Well No. 2 will be used. A 10 lb/gal brine, a fluid head of 2791 ft, and an ISIP = 830 psi, results in a fluid head of 1450 psi. These parameters resulted in a BHTP of 2280 psi and a frac gradient of 0.82 psi/ft. If a maximum error occurred and 10.2 lb/gal brine was pumped into the wellbore under the same conditions, the new fluid head would be:

Ph = 1.224 Spec. Gravity x 0.433 psi/ft x 2791 ft = 1479 psi.

The bottom hole treating pressure would calculate as follows:

BHTP = ISIP + Ph = 830 + 1479 = 2309 psi.

The resultant frac gradient would be 0.83 psi/ft. The uncertainty of the frac gradient varying from 0.82 psi/ft to 0.83 psi/ft is insignificant.

Table 10-1A gives the pressure at the top of Mt. Simon in each well at the facility using the established 0.75 psi/ft maximum gradient.

10.2.4 Bottomhole Temperature and Pressure

An original bottomhole temperature was not recorded during the drilling and completion of any of the Vickery wells.

A temperature of 75.30F at 2500 ft was measured on September 19, 1983 in Well No. 6. This temperature gives a gradient of 1.00F/100 ft using an average surface temperature of 50.50F.

An original bottomhole pressure was measured during a drill stem test in Well No. 1 on March 16, 1972 before injection of waste was initiated. A pressure of 1132 psi was recorded at 2745 ft after swabbing the hole. This pressure gives a pressure gradient of 0.412 psi/ft.

Using a pressure gradient of 0.412 psi/ft gives a pressure of 1157 psi at 2808 ft, the top of the Mt. Simon in the #1-A disposal well. This pressure is assumed to be the original BHP at that depth. Table 10-2 shows the bottomhole temperature and pressure corresponding to depth for all the Vickery wells.

10.2.5 Chemical Characteristics of Formation Fluid

Formation water samples were obtained from two wells, Well No. 1 and Well No. 4 before injection was initiated (1972 and 1976, respectively). The analyses are presented in Table 10-3. The formation fluid is a sodium chloride solution with calcium/

TABLE 10-1A

CALCULATED MAXIMUM FORMATION PRESSURE

Well Number	Depth from Ground Level (Feet)	Pressure (psi)
1A	2798	2031
2	2794	2096
3	2789	2092
4	2803	2102
5	2782	2087
6	2786	2090

Maximum pressures are calculated based on a pressure gradient of 0.75 psi/foot of well depth, and the depth to the top of the Mt. Simon.

TABLE 10-2

MEASURED BOTTOMHOLE PRESSURES (BHP) AND TEMPERATURES (BHT)

		MEASURED			WELLBORE FLUID	TOP OF MT. SIMON		FORMATION FLUID	MT. SIMON DATUM (-2192 subsea)	
DATE	WELL	DEPTH ft	BHP[1] psi	BHT °F	GRADIENT[2] psi/ft	DEPTH ft	BHP psi	GRADIENT[3] psi/ft	DEPTH ft	BHP psi
25-Aug-87	1A	2735	1314.3	71.5	0.433	2808	1346	0.466	2808	1346
12-Sep-87	2	2750	1293.6	66.5	0.433	2803	1317	0.466	2808	1319
15-Jul-87	3	2841	1312	64.5	0.433	2800	1294	0.466	2810	1299
25-Aug-87	4	2735	1269.9	70.1	0.433	2812	1303	0.466	2810	1302
11-Sep-87	5	2735	1315.6	74.2	0.433	2791	1340	0.466	2810	1348
16-Aug-87	6	2735	1312.04	70.0	0.433	2796	1338	0.466	2807	1344

[1]Wells were shut in 36 hours prior to measurements but pressure was continuing to decline.

[2]Wells were filled with fresh water.

[3]Formation in the interwell area is saturated with waste stream (1.074 s.g.).

TABLE 10-3

FORMATION WATER ANALYSES

	Well No. 1 (Mt. Simon) by Halliburton 5-5-72	Well No. 1 (Mt. Simon) by Dowell 4-10-72	Well No. 4 (Mt. Simon) by CWM Laboratory August, 1976
Specific Gravity	1.095 at 75 °F	1.1 at 60 °F	--
Viscosity, cp	1.38 at 80 °F	--	--
pH, pH units	6.4	6.0	--
Total Dissolved Solids, mg/l	126,000	126,315	--
Chlorides, mg/l	78,000	78,000	83,000
Sulfate, mg/l	817	760	--
Calcium, mg/l	11,900	11,750	--
Magnesium, mg/l	2,250	2,250	--
Sodium, mg/l	33,100	33,500	--
Iron, mg/l	0	--	--
Barium, mg/l	--	--	--
Strontium, mg/l	--	--	--
Bicarbonate, mg/l	49	55	--
Sample Method	DST	DST	Air Lift until Cl-Stabilize
Sample Depth, Ft	2757 to 2927	2757 to 2927	--

NOTES:

mg/l = milligrams per liter cp = centipoise

°F = degrees Fahrenheit DST = drillstem test

-- denotes no information available

magnesium sulfate. The Mt. Simon sample from Well No. 4 was analyzed for chlorides only, and the chloride value from this well better represents the formation fluid since the well was backflowed until the chloride value of the formation water stabilized. The other samples may have been slightly diluted with drilling fluid or mud filtrate.

10.2.6 Waste Water Compatibility

Compatibility testing with formation water was done by Halliburton in conjunction with completion of Well No. 1. The testing for Well No. 1 demonstrated that mixing of the injected waste water with connate water resulted in precipitation of calcium sulfate. For this reason, a fresh water buffer fluid was injected into each newly constructed well to displace connate water away from the wellbore and ahead of the waste fluid front. For Well No. 1 core, the Halliburton tests were conducted with connate water, waste effluent, and a 1:1 mixture of connate water:waste. Very minor differences in permeability were encountered.

The permeability of the Precambrian basement to brine or waste was not tested. Permeability to air in a sample from 2926.7 feet in Disposal Well No. 1 was less than .0005 md (the limit of the test equipment) and porosity was .6 percent. The lithology of the basement in the No. 1 well was petrographically described as an alkali feldspar granite.

Testing by ERCO Petroleum Services, Inc. was done on a Mt. Simon core plug from Well No. 5 (from 2,850 ft.). Two acid wastes were injected with little change in the base permeability. However, some fines were generated as a result of acid reaction with the dolomitic portion of the matrix

In core testing, fines are free to exit the core, usually resulting in increased permeability due to acidization. Downhole, fines are not free to migrate out of the test media; therefore, formation of calcium sulfate and small fines could actually decrease permeability and serve to channel flow into areas of silica cementation. Permeability could also increase if the increased flow area due to acid reaction exceeds the flow area plugged due to precipitates and fines.

Core flow testing was done by ERCO Petroleum Services, Inc. to determine core compatibility of various blends. Core material from Well Nos. 2, 4, and 5 was evaluated, In each case permeability reductions occurred due to formation of mobile fines generated from acid reaction with the core matrix.

Vickery has conducted both core analysis and core compatibility testing in conjunction with the Waste Analysis Plan for evaluating future wastes.

Testing has shown that the Mt. Simon contains sufficient clay to exhibit sensitivity to fresh water but with proper pretreatment or blending, the Vickery waste stream is safely injected.

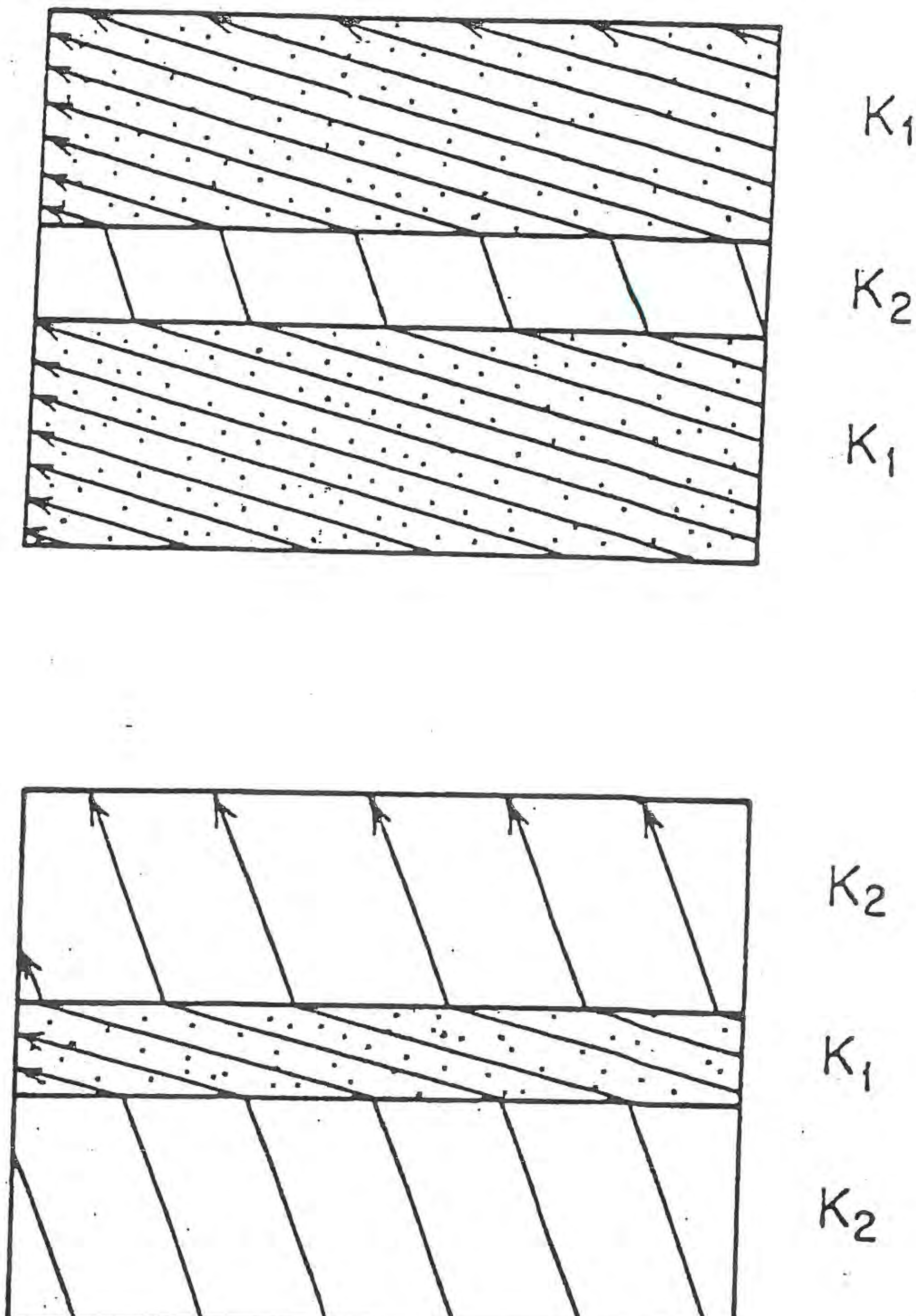
10.3 Containment Interval

10.3.1 Lithology, Thickness

The containment interval is composed of alternating sequences of carbonates and clastics of the Rome, Conasauga, Kerbel and Knox Formations. The lithology of these formations was discussed in detail in **Attachment D of this document.**

The thickness of the containment interval is approximately 440 feet and includes zones which will arrest fluid movement as well as several "bleed off" zones. A "bleed off" zone is a stratigraphic interval containing greater hydraulic conductivity (related to permeability) than the intervals above and below it. When groundwater flowlines cross a boundary between formations with different hydraulic conductivities they are refracted. In a system composed of heterogenous layers and subject to a hydraulic gradient oriented perpendicular to the layering, fluid will move in a direction basically perpendicular to the layering in low conductivity units and basically parallel to the layering in high conductivity units on either side of the interface. Figure 10-11 demonstrates this concept. Fluid flow is dispersed laterally in a bleed off zone, and pressure gradient is significantly reduced in the down gradient layers. A more complete treatment of this phenomena can be found in Freeze and Cherry (1979), Chapter 5.1.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate



HYDRAULIC CONDUCTIVITY $\frac{K_1}{K_2} = 10$

FIGURE 10-11

REFRACTION OF FLOWLINES IN LAYERED SYSTEMS water quality and an annual report that also includes formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

The Rome Formation directly overlies the Mt. Simon injection interval. The Middle Rome dolomitic sandstone will act as a significant bleed off zone to reduce upward acting injection zone pressures.

10.3.2 Porosity and Permeability

10.3.2.1 Testing History

Porosity and permeability testing has been carried out on the Vickery cores in multiple stages, utilizing equipment of different sensitivity. Within the containment interval, stratigraphic zones of low permeability are of particular interest, and the capability of the core testing procedure to detect and measure low permeabilities is critical.

Waste Disposal Wells Nos. 4 and 5 were the most extensively cored within the containment interval. Initial testing of these cores, in 1976 and 1980 respectively, was recorded to a minimum permeability to air of only .1 md and minimum porosity of 3 percent. The cores were sampled every foot in these analyses, creating an extensive, nearly continuous data record, but not truly adequate for evaluating low permeability zones.

In the fall of 1987 Vickery had additional porosity and permeability testing performed on selected containment interval zones from Disposal Wells Nos. 2, 4 and 5, with No. 4 and 5 being the most extensively tested. The selected core plugs were tested for permeability to air to .01 md, and permeability to 100,000 ppm NaCl brine to a minimum of .0001 md.

In the Fall of 1989, a relatively minor amount of porosity and permeability testing was carried out in conjunction with significant petrographic work performed on the cores from Disposal Wells Nos. 1, 2, 4 and 5. This work involved testing permeability to air to a minimum of .0001 md, and porosity to a minimum of .1 percent. Additionally, three Lower Rome Dolomite (Shady) samples, one Conasauga and one Knox sample were tested for vertical permeability to 100,000 ppm NaCl brine to a minimum of .000001 md.

In 1992 testing was completed on an extensive round of flow through studies using Vickery core materials and synthetic waste. Also, significant additional petrography work was performed before and after the flow through tests. The complete report of this testing consisted of nine volumes, and was submitted to the USEPA and ODNR. . The testing confirmed the conservative nature of the input data for the reservoir modeling.

10.3.2.2 Data Analysis

The varying sensitivities of the testing described in the preceding section makes analysis of low permeability zones within the containment interval rather difficult since a large amount of the rock materials sampled have permeabilities less than the value that could be measured at the time of testing. In an attempt to overcome this problem, average porosity and permeability for various formations, or formation segments, will be grouped according to the sensitivity of the data utilized, i.e. permeability values measured to .1 md, .01 md and .0001 md.

Since the equipment utilized in all the various analyses was capable of recording maximum porosity and permeability values encountered but not the minimum values, all the following "average" data should be regarded as conservative since the recorded average porosity and permeability are less than the true population average.

All porosities are averaged arithmetically. All vertical permeabilities are averaged using the harmonic mean. There is some uncertainty regarding the best measurement statistic for the "average" horizontal permeability, the choice being either the arithmetic mean or the geometric mean. The geometric mean is often markedly lower than the arithmetic mean for a sampled population.

Richardson, et.al. (1987) states that,

"It is usually observed that arithmetic averages of foot-by-foot horizontal permeabilities measured parallel to the bedding planes in the cores agree with permeabilities calculated from well tests. This is logical because ... arithmetic averaging assumes that flow occurs through the various strata parallel to the bedding planes. In this conceptual model, a consistent assumption is that vertical permeabilities measured perpendicular to the bedding planes should be averaged harmonically (in series) to reflect flow in the vertical direction..."

Fetter (1988), referring to hydraulic conductivity values obtain from tests of several monitoring wells areally distributed in the same aquifer, states that,

"An arithmetic mean of such a sample population tends to give more weight to the more permeable values. Some hydrogeologists believe that a more representative description of the average hydraulic conductivity of a hydrologic unit is the geometric mean. This is determined by taking the natural log of each value, finding the mean of the natural logs and then obtaining the exponential (ex) of that value to arrive at the geometric mean."

Vickery believes that arithmetic means are the more appropriate measurement for representing horizontal permeability in layered systems when utilizing the type of data available at the Vickery site. Both arithmetic and geometric values are presented in several tables in this document for comparative purposes.

Table 10-4 summarizes the porosity and permeability to air data, Table 10-5 summarizes permeability to 100,000 ppm NaCl brine. Table 10-5A provides details of the brine permeability testing. Table 10-5 demonstrates the difference in arithmetic verses geometric means for horizontal permeability.

The values of porosity and permeability used to define the various layers of the reservoir model are conservative when compared to the measured values indicated in Tables 10-4 and 10-5. Figure 10-12 shows the porosity and permeability values used in the model.

Figure 10-13 shows porosity and permeability data from Disposal Well No. 4 and the subdivision of the Rome Formation. Figure 10-14 shows the subdivisions of the Conasauga Formation with data obtained from the No. 5 well.

10.3.2.3 Porosity Development and Diagenesis

From the extensive petrographic study carried out by Vickery

on the cores of Disposal Wells Nos. 2, 4 and 5 the following generalizations can be made about containment interval porosity development, and diagenesis.

TABLE 10-4

POROSITY AND PERMEABILITY TO AIR

Formation		Testing Period		
		pre 1980	1987	1989
BLACK RIVER (Actually in Confining Zone, data from ODNR No.1 M. and B. Asphalt, Seneca Co., OH)	N	0	0	17
	K_h(md)			.0012
	ϕ_h(%)			1.96
	N	0	0	17
	K_v(md)			.00054
	ϕ_v(%)			NA
KNOX	N	39	2	0
	K_h(md)	17.06	62.65	
	ϕ_h (%)	6.92	13.85	
	N	0	2	8
	K_v(md)		.22	.0002
	ϕ_v(%)		10.6	7.25
KERBEL	N	149	7	0
	K_h(md)	26.28	63.68	
	ϕ_h(%)	11.92	11.57	
	N	0	7	11
	K_v(md)		.22	.0011
	ϕ_v(%)		11.65	10.72
CONASAUGA	N	177	7	0
	k_h(md)	50.14	85.05	
	ϕ_h (%)	12.05	14.36	
	N	0	7	27
	K_v(md)		.076	.00037
	ϕ_v(%)		13.63	11.21
UPPER ROME DOLOMITE	N	34	3	0
	K_h(md)	1.189	.593	
	ϕ_h(%)	4.32	6.5	
	N	0	3	2
	K_v(md)		.024	.00018
	ϕ_v(%)		4.43	4.15

TABLE 10-4 (Page 2 of 2)

MIDDLE ROME DOLOMITIC SAND	N	30	3	0
	K_h (md)	9.50	157.0	
	ϕ_h (%)	10.27	16.5	
	N	0	3	7
	K_v (md)		.075	.00023
	ϕ_v (%)		14.07	9.01
LOWER ROME DOLOMITE (SHADY)	N	28	1	0
	K_h (md)	.574	.02	
	ϕ_h (%)	4.29	2.3	
	N	0	1	14
	K_v (md)		.01	.00013
	ϕ_v (%)		4.8	3.61

N = # of Samples
K_v= Harmonic mean
K_h= Arithmetic mean
ϕ_h= Arithmetic mean

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Knox	2387.3	5	1989		.000024		2.4
Knox	2390.0	5	1984		.0034		6.3
Knox	2394.4	5	1987	.56		8.4	
Knox	2394-95	5	1987		.01		8.1
Knox	2402.0	5	1987	12.0		19.3	
Knox	2402-03	5	1987		6.7		13.1
Kerbel	2442.0	4	1987	114.0		14.9	
Kerbel	2442-43	4	1987		12.0		14.3
Kerbel	2448.3	4	1987	.06		6.7	
Kerbel	2448-49	4	1987		.01		6.2
Kerbel	2454.2	4	1987	.29		9.2	
Kerbel	2454-55	4	1987		.25		9.6
Kerbel	2492.3	4	1987	65.0		21.6	
Kerbel	2492-93	4	1987		4.3		21.0
Kerbel	2436.1	5	1987	.39		9.8	
Kerbel	2436-37	5	1987		.22		9.0
Kerbel	2438.4	5	1987	.08		8.4	
Kerbel	2438-39	5	1987		.04		8.8
Kerbel	2440.0	5	1984	.75		10.9	
Kerbel	2445.1	5	1987	1.4		10.4	
Kerbel	2445-46	5	1987		1.1		12.6
Kerbel	2477.0	5	1984	8.1		26.8	
Conasauga	2497.1	2	1987	35.0		11.3	
Conasauga	2497-98	2	1987		.17		10.8
Conasauga	2569.9	2	1987	.02		12.5	
Conasauga	2569-70	2	1987		.01		12.7
Conasauga	2509.9	4	1989		.000588		4.7
Conasauga	2518.2	4	1987	.001		5.4	
Conasauga	2518-19	4	1987		.0007		6.4
Conasauga	2546.9	4	1987	43.0		19.9	
Conasauga	2546-47	4	1987		.06		15.3
Conasauga	2564.5	4	1987	49.0		18.6	
Conasauga	2564-65	4	1987		13.0		15.4
Conasauga	2507.0	5	1984		.0034		6.3

TABLE 10-5A

SUMMARY OF POROSITY AND LIQUID PERMEABILITY TESTING
(Permeability Tests Used 100,000 ppm NaCl as the Saturant Fluid)

Formation*	Depth (ft)	Well #	Test Date** (Year)	Kh (md)	Kv (md)	Øh (%)	Øv (%)
Conasauga	2519.6	5	1987	133.0		24.2	
Conasauga	2519-20	5	1987		1.8		23.7
Conasauga	2525.0	5	1984	32.1		22.8	
Conasauga	2538.0	5	1984	27.0		14.6	
Conasauga	2571.3	5	1987	.01		8.6	
Conasauga	2571-72	5	1987		.0003		11.1
Upper Rome	2585.4	5	1987	.08		7.5	
Upper Rome	2585-86	5	1987		.01		4.1
Upper Rome	2590.6	5	1987	.0008		3.9	
Upper Rome	2590-91	5	1987		.01		3.0
Upper Rome	2594.8	5	1987	.001		8.1	
Upper Rome	2594-95	5	1987		.001		6.2
Middle Rome	2704.3	4	1987	.01		7.7	
Middle Rome	2704-05	4	1987		.005		7.0
Middle Rome	2727.2	4	1987	5.6		16.7	
Middle Rome	2727-28	4	1987		.03		14.2
Middle Rome	2730.2	4	1987	311.0		25.1	
Middle Rome	2730-31	4	1987		11.0		21.0
Lower Rome	2800.0	4	1989		.000022		0.2
Lower Rome	2807.5	4	1989		.000092		1.4
Lower Rome	2786.6	5	1987	.0001		2.3	
Lower Rome	2786-87	5	1987		.0006		4.8
Lower Rome	2790.5	5	1989		.000036		3.9

* Formation boundaries utilized here are tied to the determinations made during the 1989 petrographic study performed on the CWM Vickery cores. Please refer to Table 9-1 and Appendix P.

**1984 and 1987 data is in Appendix I. 1989 data is in Appendix P.

Kh = Liquid permeability in a horizontal plug.
Kv = Liquid permeability in a vertical plug.
Øh = Porosity in a horizontal plug.
Øv = Porosity in a vertical plug.

TABLE 10-5

PERMEABILITY TO 100,000 PPM NaCl BRINE

Formation*	N	Kh_a(md)	Kh_g(md)	N	Kv(md)
Knox	2	6.28	2.59	3	.0000951
Kerbel	9	20.23	1.48	7	.0519
Conasauga	9	35.46	2.285	8	.00131
Upper Rome Dolo.	3	.027	.0040	3	.0025
Mid Rome Sand	3	105.5	2.592	3	.0129
Lower Rome Dolo.	1	.0001	.0001	4	.0000466

N = # of Samples
Kv= Harmonic mean
Kh_a = Arithmetic mean
Kh_g = Geometric mean

* Determination of which formation particular sample depths represent is based on the 1989 petrographic study, see Table 9-1. See Table 11-5A for details of samples utilized in this table.

FIGURE 10-12

Hydraulic properties used for analysis of vertical pressurization and waste migration.

Model Layer	Unit	Horizontal Permeability (md)	Vertical Permeability (md)	Porosity
1	Black River	0.10	0.01	0.05
2	Black River	0.10	0.01	0.05
3	Black River	0.10	0.01	0.05
4	Wells Creek	0.014	0.0014	0.05
5	Knox	5	0.5	0.05
6	Knox	5	0.5	0.05
7	Knox	5	0.5	0.05
8	Kerbel	20	2	0.10
9	Kerbel	20	2	0.10
10	Conasauga Silty Sand	20	20	0.15
11	Conasauga Shale	0.014	0.0014	0.06
12	Conasauga Shale	0.014	0.0014	0.06
13	Conasauga Silty Sand	35	35	0.15
14	Conasauga Silty Sand	35	35	0.15
15	Conasauga Silty Sand	35	35	0.15
16	Conasauga Silty Sand	35	35	0.15
17	Rome Dolomite	0.05	0.005	0.03
18	Rome Dolomite	0.05	0.005	0.03
19	Rome Dolomite	0.05	0.005	0.03
20	Rome Dolomite	0.05	0.005	0.03
21	Rome Dolomite	0.05	0.005	0.03
22	Rome Silty Sand	5	5	0.10
23	Rome Silty Sand	5	5	0.10
24	Rome Dolomite	0.006	0.0006	0.03
25	Rome Dolomite	0.006	0.0006	0.03
26	Rome Dolomite	0.006	0.0006	0.03
27	Rome Dolomite	0.006	0.0006	0.03
28	Rome Dolomite	0.006	0.0006	0.03
29	Rome Dolomite	0.006	0.0006	0.03
30	Rome Dolomite	0.006	0.0006	0.03
31	Mt. Simon Sandstone	42	42	0.15
32	Mt. Simon Sandstone	42	42	0.15
33	Mt. Simon Sandstone	42	42	0.15

DISPOSAL WELL NO.4
ROME FORMATION

SAMPLE NUMBER	DEPTH FEET	PERMEABILITY MILLIDARCYS HORIZONTAL	PERMEABILITY MILLIDARCYS VERTICAL	POROSITY PERCENT	
177	2694.3	<0.10		3.0	
178	2695.5	<0.10		<3.0	
179	2696.5	<0.10		4.4	
180	2697.5	<0.10		<3.0	
181	2698.5	<0.10		3.8	
182	2699.5	0.12		4.9	UPPER DOLOMITE
183	2700.5	<0.10		5.8	
184	2701.5	<0.10		6.5	
185	2702.5	<0.10		6.8	
186	2703.5	<0.10		5.3	
187	2704.5	<0.10		7.1	
188	2705.5	<0.10		<3.0	
189	2706.5	<0.10		9.3	
190	2707.5	1.2		9.6	
191	2708.5	1.7		10.3	
192	2709.5	2.0		10.2	
193	2710.5	1.6		11.0	
194	2711.5	8.6		9.8	
195	2712.5	1.4		13.0	
196	2713.5	5.4		15.1	
197	2714.5	1.0		15.4	
198	2715.5	3.6		13.9	
199	2716.5	0.21		10.0	
200	2717.5	30.		19.8	
201	2718.5	44.		21.3	
202	2719.5	0.17		9.5	
203	2720.5	1.2		10.5	
204	2721.5	<0.10		9.7	
205	2722.5	1.2		9.8	MIDDLE DOLOMITIC SANDSTONE
206	2723.5	0.13		5.6	
207	2724.5	0.85		10.6	
208	2725.5	5.2		12.2	
209	2726.5	10.		15.5	
210	2727.5	163.		24.3	
211	2728.5	0.30		9.4	
212	2729.5	0.63		11.0	
213	2730.5	<0.10		3.0	
214	2731.5	0.20		6.4	
215	2732.5	<0.10		<3.0	
216	2733.5	<0.10		<3.0	
217	2734.5	<0.10		<3.0	
218	2735.5	0.62		8.8	
219	2736.5	<0.10		3.7	
220	2797.5	<0.10		<3.0	
221	2798.5	<0.10		<3.0	
222	2799.5	0.27		4.9	
223	2800.5	<0.10		<3.0	
224	2801.5	<0.10		<3.0	
225	2802.5	<0.10		6.3	
226	2803.5	<0.10		4.0	
227	2804.5	5.4		8.3	
228	2805.5	<0.10		<3.0	
229	2806.5	<0.10		<3.0	LOWER DOLOMITE (SHADY)
230	2807.5	<0.10		<3.0	
231	2808.5	<0.10		<3.0	
232	2809.5	<0.10		<3.0	
233	2810.5	<0.10		<3.0	
234	2811.5	<0.10		<3.0	
235	2812.5	<0.10		<3.0	

MAJOR HORIZONTAL POROSITY AND PERMEABILITY DIVISIONS

FIGURE 10-13

DISPOSAL WELL NO.5

CONASAUGA FORMATION

SMP. NO.	DEPTH	PERM. TO AIR MD. MAXIMUM	90 DEG	VERT.	POROSITY HEX. FLD.	
105	2490.0-91.0	17.0	15.0		11.7	
106	2491.0-92.0	5.3	4.6		11.4	
107	2492.0-93.0	4.2	3.8		9.1	SILTY SANDSTONE
108	2493.0-94.0	5.6	3.8		8.0	
109	2494.0-95.0	79.0	63.0		5.1	
110	2495.0-96.0	*	2.9		6.7	
111	2496.0-97.0	*	3.5		9.3	
112	2497.0-98.0	4.0	3.7		11.0	
113	2498.0-99.0	<0.1	<0.1		5.3	
114	2499.0-00.0	<0.1	<0.1		3.8	
115	2500.0-01.0	<0.1	<0.1		4.2	
116	2501.0-02.0	<0.1	<0.1		5.3	
117	2502.0-03.0	*	<0.1		5.1	
118	2503.0-04.0	<0.1	<0.1		4.6	
119	2504.0-05.0	<0.1	<0.1		4.2	
120	2505.0-06.0	*	<0.1		4.0	
121	2506.0-07.0	<0.1	<0.1		3.8	
122	2507.0-08.0	<0.1	<0.1		3.6	
123	2508.0-09.0	<0.1	<0.1		5.1	SILTY SHALE
124	2509.0-10.0	<0.1	<0.1		7.6	
125	2510.0-11.0	<0.1	<0.1		9.0	
126	2511.0-12.0	<0.1	<0.1		8.4	
127	2512.0-13.0	<0.1	<0.1		7.2	
128	2513.0-14.0	<0.1	<0.1		14.3	
129	2514.0-15.0	<0.1	<0.1		6.5	
130	2515.0-16.0	0.7	10.6		9.5	
131	2516.0-17.0	1.3	0.6		10.0	
132	2517.0-18.0	27.0	25.0		12.6	
133	2518.0-19.0	141.0	132.0		19.4	
134	2519.0-20.0	431.0	399.0		22.3	
135	2520.0-21.0	37.0	36.0		15.5	
136	2521.0-22.0	29.0	23.0		13.1	
137	2522.0-23.0	72.0	68.0		21.0	
138	2523.0-24.0	53.0	48.0		18.6	
139	2524.0-25.0	118.0	110.0		20.8	
140	2525.0-26.0	108.0	98.0		22.3	
141	2526.0-27.0	58.0	58.0		13.1	
142	2527.0-28.0	18.0	15.0		12.7	
143	2528.0-29.0	45.0	43.0		17.1	
144	2529.0-30.0	6.4	5.6		9.5	
145	2530.0-31.0	1.9	0.8		9.6	
146	2531.0-32.0	22.0	18.0		12.2	
147	2532.0-33.0	36.0	29.0		11.1	
148	2533.0-34.0	54.0	45.0		14.1	
149	2534.0-35.0	408.0	243.0		14.2	
150	2535.0-36.0	57.0	54.0		14.2	
151	2536.0-37.0	69.0	67.0		13.3	
152	2537.0-38.0	78.0	75.0		13.1	
153	2538.0-39.0	60.0	59.0		13.6	
154	2539.0-40.0	60.0	57.0		14.1	
155	2540.0-41.0	90.0	85.0		14.2	
156	2541.0-42.0	68.0	67.0		15.4	
157	2542.0-43.0	62.0	59.0		15.4	
158	2543.0-44.0	83.0	79.0		19.2	
159	2544.0-45.0	126.0	114.0		19.9	
160	2545.0-46.0	62.0	56.0		17.7	
161	2546.0-47.0	52.0	51.0		20.0	SILTY SANDSTONE
162	2547.0-48.0	45.0	42.0		13.1	
163	2548.0-49.0	45.0	43.0		12.7	
164	2549.0-50.0	73.0	70.0		16.3	
165	2550.0-51.0	54.0	54.0		17.9	
166	2551.0-52.0	29.0	28.0		19.3	
167	2552.0-53.0	*	20.0		10.3	
168	2553.0-54.0	40.0	39.0		14.9	
169	2554.0-55.0	64.0	61.0		12.5	
170	2555.0-56.0	5.1	4.6		15.9	
171	2556.0-57.0	*	94.0		19.2	
172	2557.0-58.0	*	85.0		14.6	
173	2558.0-59.0	11.0	10.0		15.4	
174	2559.0-60.0	57.0	41.8		16.6	
175	2560.0-61.0	40.0	34.0		20.8	
176	2561.0-62.0	36.0	34.0		21.3	
177	2562.0-63.0	24.0	23.0		16.3	
178	2563.0-64.0	11.0	10.0		8.7	
179	2564.0-65.0	9.6	7.9		9.7	
180	2565.0-66.0	2.2	1.1		13.6	
181	2566.0-67.0	0.3	0.2		11.3	
182	2567.0-68.0	3.6	3.2		12.0	
183	2568.0-69.0	2.0	1.4		15.4	
184	2569.0-70.0	1.9	1.9		10.8	
185	2570.0-71.0	1.8	1.7		9.3	
186	2571.0-72.0	<0.1	<0.1		5.7	
187	2572.0-73.0	0.1	0.1		6.7	
188	2573.0-74.0	<0.1	<0.1		7.8	
189	2574.0-75.0	1.2	1.1		9.5	
190	2575.0-76.0	0.4	0.4		6.9	
191	2576.0-77.0	0.3	0.2		5.6	
192	2577.0-78.0	0.8	0.4		8.6	
193	2578.0-79.0	<0.1	<0.1		5.4	

FIGURE 10-14

MAJOR HORIZONTAL

10.3.2.3.1 Rome Formation

The Rome Formation can be divided into three units. The lowermost unit is a sandy grainstone dolomite. The middle section is a dolomitic fine to very fine grained sandstone. The upper unit is a sandy grainstone dolomite similar to the lowermost unit.

Although very few samples were examined in detail from the Middle Rome, diagenetic events affecting porosity development in the Middle Rome include initial quartz overgrowth development and K-feldspar development which is often followed by extensive precipitation by pore-filling finely crystalline dolomite. Dolomitization was followed by dissolution of unstable framework grains leading to the formation of moldic and intragranular pores. In many cases, dolomite cement appears to have occluded intergranular pores, and therefore the predominant pore types are intragranular and moldic. These pores appear to be very poorly interconnected and permeability values are typically below 1 md.

Dolomitized grainstones of the uppermost and lowermost Rome contain very low levels of visible porosity and contain high amounts of pore filling dolomite cement. Rare visible pores are generally isolated and consist largely of moldic and vuggy dissolution pores. A small number of fractures occur in both the lower and upper Rome. Blue-light fluorescent microscopy and standard thin section petrography show that the majority of fractures are laterally discontinuous and appear occluded laterally by dolomite cement, and less commonly by calcite cement. Some fractures are laterally continuous and display especially sharp breaks, free of mineralization throughout the length of the fracture. These fractures appear to have been induced, perhaps during the coring process. Permeability to air values in the upper and lower Rome are generally below 1 md and in many cases, below 0.0001 md. Vertical permeability to 100,000 ppm NaCl brine measured in the lower Rome averaged 0.000047 md from 4 samples.

10.3.2.3.2 Conasauga Formation

The Conasauga is variable lithologically, consisting of finely interlaminated siltstones, very fine-grained sandstones and dolomites in the upper portion of the formation, and dolomite cemented fine to very fine-grained sandstone in the lower Conasauga.

In the upper portion of the Conasauga, visible porosity is negligible within dolomite and clay-rich siltstone laminations. Visible porosity can also be very low along relatively clean carbonate cemented very fine grained sandstone laminations. Some fine grained sandstone laminations display well developed visible porosity. Burial diagenetic influences in these sandstones include early formation of poorly developed grain-coating chlorite, which was succeeded by quartz overgrowth cementation, which was followed in turn by K-feldspar overgrowth cementation, detrital framework grain dissolution, and pore-bridging illite precipitation. Dolomite cement appears to post-date illite formation, occurring in coarse rhombic pore-filling and occasionally grain replacing crystals. Visible porosity can be as high as 23% within thin sandstone beds in the upper Conasauga. In such beds, intergranular and secondary dissolution pores are present in nearly equal proportions and often appear well interconnected laterally. However, such beds are thin and are often bounded vertically by relatively tight beds (i..e. dolomites, dolomitic siltstones).

With the exception of the lowermost 15 feet of the lower Conasauga (which is tightly cemented by pervasive dolomite cement), the lower Conasauga consists of fairly clean thick-bedded sandstone which often displays high amounts of visible porosity in thin section. These sandstones display similar diagenetic relationships to those of clean sandstones in the upper Conasauga. Visible porosity commonly exceeds 15%, with abundant intergranular and secondary pores. Measured permeability values in this interval commonly exceed 50 md.

10.3.2.3.3 Kerbel Formation

The Kerbel consists largely of relatively clean, very fine to fine grained sandstones that contain variable amounts of dolomite cement. Visible porosity in the Kerbel ranges from 4.0-20% with pore-filling dolomite cement acting as the controlling factor in porosity distribution. Dolomite cement is both grain replacing and pore-filling (most common mode of occurrence) and often displays a very even distribution of medium subhedral crystals. Dolomite cement appears to have post-dated quartz and feldspar overgrowth cementation and predates the development of secondary grain-moldic and intragranular pores. Dolomite cement is present in almost every sandstone examined in the Kerbel and occurs most commonly within intergranular pores. Where dolomite cement exceeds 30%, visible porosity rarely exceeds 10%. Dolomite cement not only effects permeability by reducing overall porosity, it appears to also effect permeability by reducing overall pore size and occluding interconnection between pores.

Sandstones with high amounts of porosity occur in both the upper and lower Kerbel, in which measured whole core permeability typically ranges from 10-50 md. However, sandstones containing high amounts of dolomite cement are common with permeability values often less than 5 md.

10.3.2.3.4 Knox Formation

The Knox samples from Well No. 4 and Well No. 5 consist of dolomite and mixed dolomite/sandstone. Visible porosity is especially low within relatively pure dolomite grainstones, where the dominant form of porosity is isolated moldic and vuggy dissolution pores. Intergranular and moldic dissolution porosity can be well developed along sandstone beds. Moldic pores are sometimes well developed in sandy dolomite beds, but appear poorly interconnected. Intergranular and secondary pores within dolomitic sandstone laminations often appear locally well interconnected, however, such laminations are commonly laterally and vertically discontinuous. Fractures are present in the Knox, but like those of the Rome Formation, most are laterally discontinuous due to dolomite cementation. There are also fractures that display especially clean breaks with no evidence whatsoever of mineralization - these are believed to have been induced during coring.

In 1993 a monitor well was installed at the interface of the Knox and Kerbel formations that is capable of monitoring formation fluid chemistry periodically and formation pressures continuously. This well is currently samples on an annual basis to evaluate water quality and an annual report that also incluses formation pressure data is prepared each year.

There has been no excess buildup in formation pressure from injection activity and water chemistry has remained stable.

10.3.3 Formation Fracture Gradient

Very little information exists on the regional fracture gradient for formations of the containment interval. According to oilfield service companies contacted the fracture gradient for the formations in the containment interval is .80 psi/ft. This is based on their experience with the Knox formation in Morrow, Holmes and Coshocton Counties. This fracture gradient is .05 psi/ft higher than the 0.75 psi/ft fracture gradient used to establish the maximum wellhead injection pressure at the Vickery site.

10.3.4 Chemical Characteristics of Formation Fluid

A water sample from the Kerbel Formation was obtained from Vickery Well No. 4 before injection was initiated in 1976. The formation fluid at this interval is similar to the Mt. Simon Formation fluid except for a lower chloride content and higher calcium and sulfate content. Formation water analysis results for the Kerbel are included in Table 10-6.

10.3.5 Waste Water Compatibility

Most of the formations in the containment interval have dolomite ($CaMg(CO_3)_2$) as a significant mineralogical constituent The general equation for the reaction of dolomite with acid is:

$$CaMg(CO_3)_2 + 4H^+ = Ca^{++} + MG^{++} + 2CO_2 + 2H_2O$$

This chemical reaction results in the neutralization of the acidic waste through the dissolution of dolomite.

URM (1984) states that the dissolution of dolomite and the resultant release of Ca^{++} in solution may result in the formation of gypsum ($CaSO_4 \bullet nH_2O$) upon reaction with sulfate in the wastestream, which may precipitate in intergranular or fracture pore spaces. This mineral precipitation would cause a reduction in permeability within the naturally low permeability formations of the containment interval.

Testing of Well No. 1 Mt. Simon sandstone (containing a minor dolomite component) demonstrated that mixing of connate water and injected acidic waste water resulted in the precipitation of calcium sulfate

Results of other studies (International Symposium on Subsurface Injection of Liquid Wastes, 1986), indicate the possibility that the permeability reduction of dolomite samples seen after the samples were flowed with synthetic brine (to obtain repeatable results) then with pickling liquor (acid) was caused by precipitation of iron carbonate.

TABLE 10-6

FORMATION WATER ANALYSES

OF

THE KERBEL

Well No. 4
(Kerbel)
by CWM Laboratory
8-5-76

Specific Gravity	1.067
Viscosity, cp	--
pH, pH units	--
Total Dissolved Solids, mg/l	--
Chlorides, mg/l	62,037
Sulfate, mg/l	1,143
Calcium, mg/l	7,900
Magnesium, mg/l	--
Sodium, mg/l	--
Iron, mg/l	2.18
Barium, mg/l	--
Strontium, mg/l	--
Bicarbonate, mg/l	--
Sample Method	DST
Sample Depth, ft	--

NOTES:

mg/l = milligrams per liter   cp = centipoise

°F = degrees Fahrenheit   DST = drillstem test

-- denotes no information available

10.4 References

Fetter, C.W., 1988. Applied Hydrogeology, 2nd Edition, Merrill Publishing, Columbus, Ohio, 592 pgs.

International Symposium on Subsurface Injection of Liquid Wastes, 1986, sponsored by the Underground Injection Practices Council and the Association of Ground Water Scientists and Engineers, Water Well Journal Publishing Co., Dublin, Ohio.

Richardson, J.G., Sangree, J.B., Sneider, R.M., 1987. Permeability Distributions in Reservoirs, Journal of Petroleum Technology, October 1987.

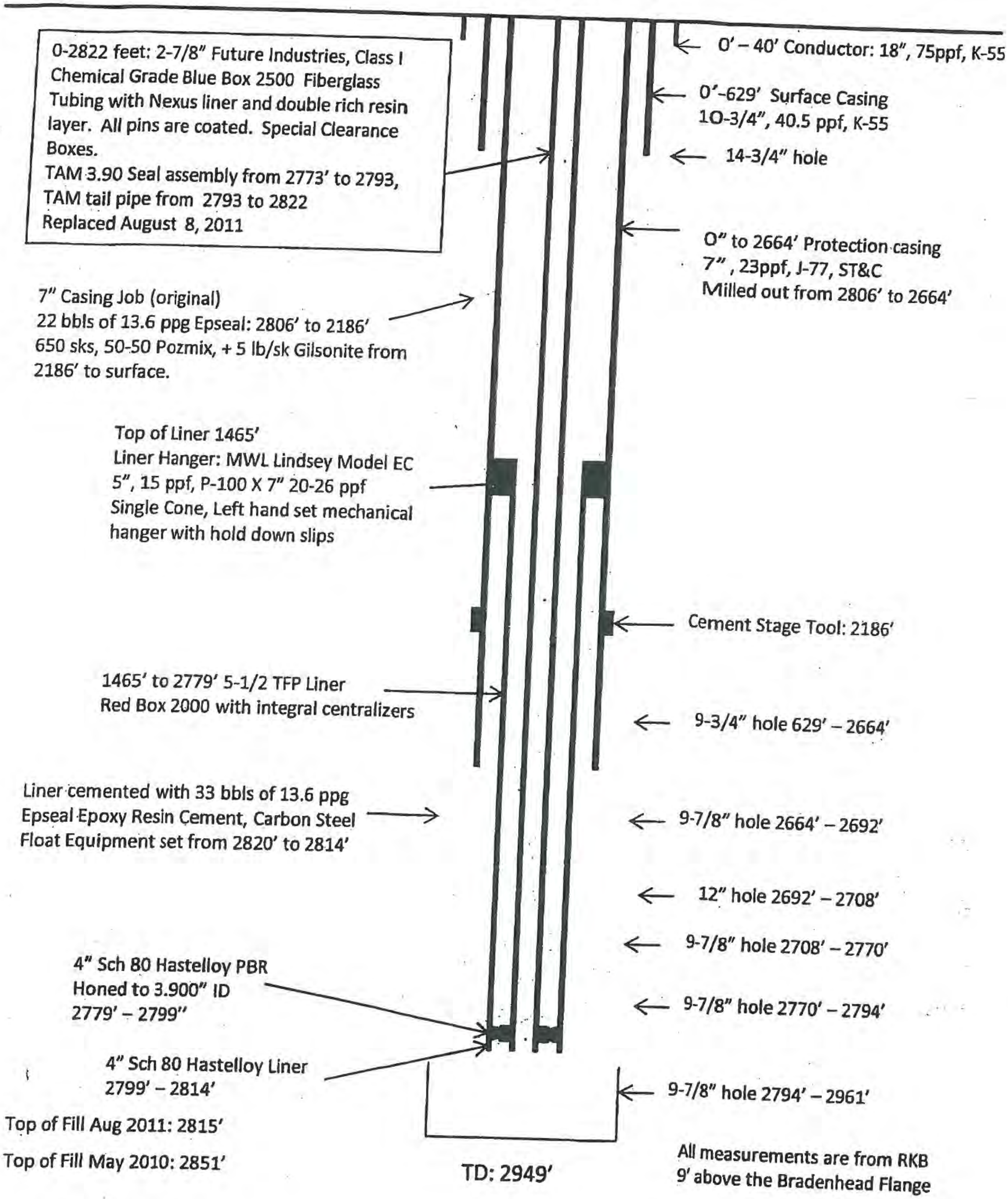
URM, 1984, Evaluation of a Subsurface Waste Injection System Near Vickery, Ohio, prepared for the Ohio Environmental Protection Agency.

ATTACHMENT C

WELL CONSTRUCTION

Figure 10-1

VICKERY ENVIRONMENTAL, INC.
SCHEMATIC: DISPOSAL WELL NO. 2



This Schematic is Not To Scale

Texas World Operations, Inc.	Drawn by: RFW, 8/25/11	VEI Well No. 2

ATTACHMENT D

OPERATING, MONITORING AND REPORTING REQUIREMENTS

OPERATING, MONITORING AND REPORTING REQUIREMENTS

	LIMITATION	MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
Characteristic	Maximum	Frequency	Frequency
* Injection Pressure	751 psig	continuous	monthly
* Bottom-hole Pressure	2102 psi	calculated value	monthly
** Injection Rate	240 gpm	continuous	monthly
** Annulus Pressure		continuous	monthly
+ Specific Gravity		continuous	monthly
Cumulative Volume		daily	monthly
Concurrent Measurements of:			
Annulus Sight Glass Level		daily	monthly
Annular Fluid Volume		daily	monthly
Injectate Temperature		daily	monthly
++ Chemical Composition of Injected Fluid		monthly	monthly
+++ Chemical Composition of Injected Fluid		quarterly	quarterly

* Injection Pressure:

The maximum allowable surface injection pressure (MASIP) shall be calculated using the following formula:

MASIP = 2803 x [0.75 - (0.433 x 1.113)] where:
0.75 = applied fracture gradient in psi/ft
1.113 = fluid specific gravity (monthly average 1/97 - 12/13)
2803 = depth to the top of the injection interval in feet

The maximum allowable bottom-hole pressure (BHP_{max}) shall be calculated using the following formula:

BHP_{max} = (0.75) (2803)

**Injection Rate:	The combined monthly average injection rate for all permitted Class I injection wells on site shall not exceed 240 gallons per minute. The rate shall be calculated utilizing the total volume of fluid injected for a given month divided by the total number of minutes within that month.
***Annulus Pressure Requirement:	The pressure on the annulus shall be maintained continuously at least 50 psi higher than the injection pressure throughout the entire length of the tubing.
+Specific Gravity:	Specific gravity of the injectate shall be monitored continuously and the data recorded at a frequency approved by the Director. A daily maximum, minimum and average shall be reported monthly. As the specific measurement increases above 1.113, the maximum injection pressure measured at the well head shall be adjusted downward accordingly such that a bottom-hole pressure of 2102 psi is not exceeded.
++Monthly Waste Analysis:	Chemical analysis of the injectate shall be conducted monthly for, at a minimum, the parameters listed in Part II (D) (2) (a) of this permit or in accordance with the Waste Analysis Plan approved by the Director.
+++Quarterly Waste Analysis:	Chemical analysis of the injectate shall be conducted quarterly for, at a minimum, the waste constituents listed in Part II (D) (2) (b) of this permit or in accordance with the Waste Analysis Plan approved by the Director.

ATTACHMENT E

CORRECTIVE ACTION

CORRECTIVE ACTION
[OAC Rules 3745-34-07; 3745-34-30; and 3745-34-53]

A. Protection of USDW

Should upward fluid migration occur through the wellbore of any previously unknown, improperly plugged or unplugged well in the 3.5 mile radius area of review due to injection of fluids in this well, injection will be shut-in until proper plugging can be accomplished. Any flowage from such undiscovered wells will be considered noncompliance with this permit. Should any problem develop in the casing of the injection well, the injection well shall be shut-in until such repairs can be made to remedy the situation.

B. Prior Releases

In 1983, Ohio EPA retained Underground Resource Management, Inc. of Austin, Texas, to analyze information on prior releases of waste into the Knox and Kerbel Formations. In 1993, two ground water monitoring wells were installed to allow monitoring of formation pressure and ground water chemistry in the Knox and Kerbel Formations and monitoring of ground water level elevations and chemistry in the Lockport Formation (lowermost USDW). If data acquired from these ground water monitoring wells or any other relevant data indicate the upward migration of fluids from the injection zone and/or threat to a USDW, the Director may require corrective action in accordance with OAC Rules 3745-34-07, 3745-34-30, and 3745-34-53 and Part I (J) (1) of this permit.

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for Injection Well Permit Number UIC 03-72-009-PTO-I is of known quality and was obtained from samples using methods prescribed in the Ohio EPA Quality Assurance Plan and the "Waste Analysis Plan" developed as required by OAC Rule 3745-34-57. I also acknowledge the right of Ohio EPA to inspect the sampling protocols, calibration records, analytic records and methods, and relevant quality assurance and quality control information for the monitoring operations required by this permit or Chapter 3745-34 of the OAC.

__________________ Date

__________________________ Authorized Agent Signature

For __________________________