Ohio Environmental Protection Agency

John R. Kasich, Governor
Mary Taylor, Lt. Governor
Craig W. Butler, Director

August 31, 2018

Re: Buckeye Brine
Permit – Long Term
Draft for Public Comment
Underground Injection Control
Coshocton County
OHS031350001

Coshocton Public Library
ATTN: Reference Department
655 Main Street
Coshocton, Ohio 45801

Subject: Buckeye Brine Draft Issuance of Two (2) Class I Non-Hazardous UIC Permits to Operate

To Whom It May Concern:

Pursuant to Section 6111.044 of the Ohio Revised Code, Ohio EPA is proposing the enclosed draft issuance of two (2) Class I Non-Hazardous Underground Injection Control permits to operate for the Buckeye Brine, LLC facility, Coshocton, Ohio. Please retain these draft permits on the allocated shelves until a final decision on the permits is made. Copies of the draft permits and public notice are attached.

Thank you for your cooperation in making these documents available to the public. If you have any questions, please call me at (614) 644-2752.

Sincerely,

Jess Stottsberry
UIC Unit Geologist
Division of Drinking and Ground Waters

Enclosures

ec: Holly Tucker, Chief, SEDO
Lindsay Taliaferro, III, UIC Manager, DDAGW

Coshocton County

PUBLIC NOTICE

OHIO ENVIRONMENTAL PROTECTION AGENCY
ISSUANCE OF DRAFT PERMITS TO OPERATE
PUBLIC INFORMATION SESSION
PUBLIC HEARING

Notice is hereby given that the Ohio Environmental Protection Agency (Ohio EPA) has issued on August 31, 2018, two (2) Draft Permits to Operate (PTOs), numbers UIC 04-16-017-PTO-I and UIC 04-16-018-PTO-I to Buckeye Brine, LLC, Coshocton, Ohio. The Draft Permits are for Class I Non-Hazardous Wells Numbers 1 and 3 at the Buckeye Brine facility located at 23986 Airport Road in Coshocton County, Coshocton, Ohio. These proposed permits have been issued in draft form by the Ohio EPA pursuant to Section 6111.044 of the Ohio Revised Code.

Notice is hereby given that Ohio EPA will conduct an Information Session and Public Hearing on October 18, 2018 at 6:00 PM. The information session and hearing will be held at Coshocton High School, 1205 Cambridge Road, Coshocton, Ohio.

Ohio EPA's draft permits are issued to meet state requirements and regulations, found in Chapter 6111. of the Revised Code and Chapter 3745-34 of the Ohio Administrative Code. The draft action proposes to allow Buckeye Brine, LLC to operate two (2) Class I Non-Hazardous waste injection wells.

During the information session, Ohio EPA will provide information and answer questions regarding Ohio EPA's draft actions. At the public hearing, the public may present testimony to the hearing officer. All persons are entitled to attend or be represented and give written or oral comments on the draft actions at the public hearing.

Written comments on the draft permits may be submitted at the hearing or mailed to Ohio EPA, Division of Drinking and Ground Waters, Attn: UIC Unit Supervisor, P.O. Box 1049, Columbus, Ohio 43216-1049. **All comments received on or before Friday, October 26, 2018 will be considered part of the administrative record and will be considered prior to the final decision on issuance of the two (2) permits.**

Persons desiring to receive notice of further proceedings, copies of fact sheets and other information relating to the above referenced permits may contact Ohio EPA, Division of Drinking and Ground Waters, P.O. Box 1049, Columbus, Ohio 43216-1049, Attn: Jess Stottsberry, (614) 644-2752. Copies of the draft permits may be inspected at the Coshocton Public Library, 655 Main Street, Coshocton, OH; at the Ohio EPA's Southeast District Office, 2195 Front Street, Logan, OH, (740) 385-8501; or at Ohio EPA, Central Office, 50 West Town Street, Columbus, OH (614) 644-2752, by first contacting Jess Stottsberry.

Ohio Environmental Protection Agency

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I NON-HAZARDOUS WELL

Ohio Permit No.:	UIC 04-16-017-PTO-I
Date of Issuance:	
Effective Date:	
Date of Expiration:	(5 years after issuance)
Name of Applicant:	Buckeye Brine, LLC
Facility Location:	23986 Airport Road Coshocton Ohio 43812
Mailing Address:	2630 Exposition BLVD, Suite 117 Austin, Texas 78703
County:	Coshocton
Township:	Keene
Well Number:	Adams #1
Well Location:	40°18'4.3524" N/-81°50'54.387" W
Total Depth:	7270 feet below ground level (BGL) to Mt. Simon. Ground level elevation 763 feet above sea level.
Injection Interval:	Gull River to the Mt. Simon from 5898 to 7270 feet (BGL)
Containment Interval:	Trenton to Gull River from 5210 to 5898 feet (BGL)
Injection Zone:	Gull River to Mt. Simon, from 5860 to 7270 feet (BGL)
Confining Zone:	Trenton from 5210 to 5860 feet (BGL)

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 Non-Hazardous 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, F, and G.

This permit shall become effective on ________________ 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

TABLE OF CONTENTS

Page

PART I – General Permit Conditions

PART II – Well Specific Conditions

ATTACHMENTS

PART I
GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in the 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 activity in a manner that allows the movement of 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 or other private rights, or any infringement of state or local law.

This permit does not relieve the permittee of its obligation to comply with any additional regulations or requirements under the Resource Conservation and Recovery Act (RCRA) as amended or Chapter 3734 of the ORC and rules promulgated thereunder. 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 Revised Code and Part C of the federal RCRA.

B. PERMIT ACTIONS

1. Modification, Revocation, Reissuance and Termination. The Director may, for cause or upon request from the permittee, modify, revoke, and reissue, or terminate this permit in accordance with Ohio Administrative Code (OAC) Rules 3745-34-07, 3745-34-23, and 3745-34-24, and 3745-34-26. Also, the permit is subject 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 non-compliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

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), 3745-34-23, or 3745-34-25(D) 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 obtained by the Ohio EPA pursuant to this permit may be claimed as confidential. 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 at the permitted facility.

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 non-compliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from implementation of or noncompliance with this permit. Any permit noncompliance constitutes a violation of ORC Chapter 6109 or 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such non-compliance may also 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 Chapter 6111, 6109 or 3734. 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 180 days before this permit expires.

b. Permit Extensions. The condition 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 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 regulation 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.

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, including photographing, at reasonable times any facilities, equipment (including monitoring and control equipment), activity, 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 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 OAC Rule 3745-34-12 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) 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. 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 measurements taken for the purpose of monitoring shall be representative of the monitored activity. Monitoring results shall be reported monthly in accordance with OAC Rule 3745-34-38 in a format acceptable to the Director and as set forth in paragraph 12 below.

a. Monitoring the nature of injected fluids shall comply with the applicable analytical methods cited and described in Table I of 40 CFR 136.3 or in Appendix III of 40 CFR Part 261 or (in certain circumstances) by other methods that have been approved by the Administrator of U.S. EPA, or by the Director.

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 wherever 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 alterations or additions to the permitted facility. Replacement of equipment that is equivalent to existing equipment is 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. Written notice shall include discussion of the changes or activity to occur, the time frame it is expected to occur, the nature of the suspected noncompliance, and planned back-up readings, if applicable. Submittal of notice of noncompliance does not stay the applicability of any permit requirement.

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 24 hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within 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 or unless specified otherwise by the Director.

g. Monthly reports specified in OAC Rule 3745-34-38 shall be submitted by the fifteenth day of the following month. Quarterly reports shall be submitted in accordance with Part II (E) 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 immediately, in writing, if the designee or position is changed.

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

1. <u>Closure Plan.</u> A plan for closure of the well is included in Attachment A of this

permit. This plan is subject to final approval by Ohio EPA. The implementation of an 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 closure 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 activities.

2. <u>Revision of Closure Plan.</u> 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 is approved by the Director.

3. <u>Notice of Intent to Close.</u> The permittee shall notify the Director of its intent to close an injection well at least sixty (60) calendar days before closure of the well, unless a shorter notice period is approved by the Director.

4. <u>Temporary Disuse.</u> 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.

   The owner or operator of a Class I 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. <u>Closure Report.</u> 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 either:

   a. A statement that the well was closed in accordance with Attachment A of this permit; or
   b. Where actual closure differed from Attachment A of this permit, a written statement specifying the differences between Attachment A and the actual closure.

6. <u>Standards for Well Closure.</u> 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 and report this information to the Director;
   b. Conduct appropriate mechanical integrity and other 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 but are not limited to:

i. Pressure tests with liquid or gas;
ii. Radioactive tracer survey;
iii. Temperature log;
iv. Casing inspection log;
v. Cement bond log; and
vi. 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 OAC Rule 3745-34-62. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection. This permit is conditioned upon the Ohio EPA approving the owner or operator's financial assurance prior to operation of the well authorized by this permit.

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

1. Post-Closure Plan. A plan for post-closure activities has been submitted and is included in Attachment A of this permit. The plan is subject to final approval by Ohio EPA. The obligation to implement an approved post-closure plan will be part of the administrative record for this permit and the permittee shall maintain and comply with this plan as if it were fully set forth herein. The obligation to maintain, implement, and comply with the post-closure plan survives the termination of this permit or the cessation of injection activities.

   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 continue post-closure maintenance and monitoring of any ground water monitoring wells required under this permit for one (1) year and 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, as identified in the administrative record for this permit. The Director may extend the period of the post-closure monitoring upon a finding that the well may endanger a USDW.

4. Survey Plat. The permittee shall submit a current plat map to the local zoning authority upon plugging 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 Resources Management, the Coshocton County Health Department, and any other State of local authority designated by the Director upon plugging 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 plugging the well in accordance with the approved closure plan required in Part I (F) of this permit, the permittee must 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 non-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, and the period over which injection occurred.

8. Financial Responsibility for Post-Closure Care. The permittee shall submit a demonstration of financial responsibility for post-closure care, as required by Chapter 3745-34 of the OAC, for approval by the Director. The owner or operator shall comply with post-closure financial assurance requirements of OAC Chapter 3745-34. The obligation to maintain financial responsibility for post-closure care survives the termination of this permit or the cessation of injection.

H. MECHANICAL INTEGRITY (OAC RULE 3745-34-34)

1. Standards. Each injection well shall maintain mechanical integrity as defined by OAC Rule 3745-34-34. The Director or his or her authorized representative shall be present during the test for demonstration of mechanical integrity, unless the Director or his or her 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 injection well shall maintain mechanical integrity of the injection well at all times.

2. Initial Mechanical Integrity Testing [OAC Rule 3745-34-55]. Prior to injection of waste fluids, the permittee shall conduct the initial 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).
    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).
    c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I)(3).
    d. An approved casing inspection log shall be run for the entire length of the long string casing in accordance with OAC Rule 3745-34-55 (A)(3)(d).

    If the permittee or the Director or the Director's authorized representative finds that the well fails to demonstrate mechanical integrity, the permittee shall not operate the well until mechanical integrity is demonstrated, and the Director or the Director's representative gives approval to commence injection.

3. Periodic Mechanical Integrity Testing [OAC Rule 3745-34-57]. Unless otherwise approved by the Director, 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) within thirty (30) days of the anniversary date of the last field 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) within thirty (30) days of the anniversary date of the last field approved demonstration;
    c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I)(3) within thirty (30) days of the three (3) year anniversary date of the last approved field 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) every five (5) years and 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 (5) years.

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).
f. The Director may require additional or alternative tests if the test results presented by the permittee are not satisfactory to the Director to demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.

4. Prior Notice and Report. 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) (3) (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. 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.

5. Gauges. The Permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half 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 ten (10) psi increments.

6. Loss of Mechanical Integrity. If the permittee or the Director or the Director's authorized representative 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 or the Director's representative gives approval to recommence injection.

7. Mechanical Integrity Testing on Request from the Director. The permittee shall demonstrate mechanical integrity at any time upon written request from the Director.

I. FINANCIAL RESPONSIBILITY (OAC Rule 3745-34-62)

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC Chapter 3745-34.

   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 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 through 3745-55-45.

c. The permittee must 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 must 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 condition 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 must notify the Director, in writing, within ten (10) business days.

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

An owner or operator must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor of a corporate guarantee must 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 requirements found in Attachment E of 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. These said fees are non-refundable under any circumstance.

Part II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Surface Plumbing. The permittee shall not commence injection until it has obtained approval from Ohio EPA's Division of Surface Water and Ohio Department of Natural Resources on changes the permittee has made or will make to surface facility piping to ensure separation such that Class I Non-Hazardous waste fluids cannot be injected into the Class II well.

2. Siting [OAC Rule 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.

3. 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. Prior to operation, Adams #1 will need to cement the top 906' of annular space behind the 7" long string casing.

   The casing and cement used in the construction of the well 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.

4. Tubing and Packer Specifications [OAC Rule 3745-34-54 (D)]. Injection shall take place only through approved tubing with an approved packer/seal assembly 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/seal assembly specifications shall be as represented in engineering drawings contained 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.

5. 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.

2. In accordance with OAC Rule 3745-34-57 (J), the permittee shall monitor the pressure buildup in the injection zone annually. The permittee shall schedule pressure buildup testing such that one (1) of the permittee's two (2) Class I

injection wells is used for testing each year and each well shall be tested at least once every twenty-four (24) months unless otherwise approved by the Director.

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 approximate subsurface interval between 5898 feet and 7270 feet ground level (BGL) for Adams #1.

2. Injection Pressure Limitation [OAC Rule 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.
   b. Bottom hole pressure shall be limited so that a maximum of 4423 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 5898 feet BGL. The injection pressure shall be limited so that a maximum pressure of 1358 psig (measured at the surface) is not exceeded. The maximum surface injection pressure limit shall be adjusted downward if fluid specific gravity increases above 1.2, in accordance with the calculation set forth in Attachment D of this permit. Downward adjustments in injection pressure shall be made based on injectate specific gravity measurements made and recorded at least once every four (4) hours.

3. Injection Volume Limitation. The combined monthly flow rate for all permitted Class I injection wells at this facility shall not exceed 290 gallons per minute.

4. Additional Injection Limitation. No substances other than those identified and deemed acceptable for receipt and defined as non-hazardous shall be injected. The composite waste stream shall meet all compatibility requirements of OAC Rule 3745-34-57.

The permittee shall submit a certified statement attesting to compliance with this requirement at the time of the annual report. The only exception to this limitation is the injection of fluids recovered from monitor wells and other fluid required for approved well testing and/or monitoring.

5. Annulus Fluids 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 (calculated) higher than injection pressure at all times throughout the injection tubing length to the top of the packer/seal assembly, for the purpose of leak detection.

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 situations:

      i. Injection pressure measured at the wellhead equals or exceeds the limit established in Part II (C) (2) of this permit; and
      ii. When injection/annulus pressure differential falls below fifty (50) psig positive differential from the injection pressure and during conditions specified above in Part II (C).

   b. Following initial testing prior to injecting waste fluids, unless otherwise approved by the Director, the permittee shall test the automatic warning and shut-off system within thirty (30) days of the anniversary date of the last field approved demonstration. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or the Director's authorized representative. The permittee shall notify the Director of its 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 or 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 an alarm or

shutdown, in accordance with Part I (E) (12) 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 a 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 must 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]. The injection fluids shall be analyzed in accordance with the Ohio EPA approved waste analyses plan. 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) and Part II (C) (4) of this permit.

3. Waste Analysis Plan.
   a. The permittee has developed a written waste analysis plan which describes the procedures which it will carry out to comply with permit conditions (D) (1) and (D) (2) above and OAC Rule 3745-34-57. A copy of the approved plan shall be kept at the facility and available for inspection. The sampling and analyses shall be performed in a manner protective of human health, safety and the environment and shall produce results representative of the chemical composition of the waste analysis stream. At a minimum, the plan must specify:

      i. The parameters for which the waste stream 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.
      iv. The injectate sampling location.

   b. 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 the approved Waste Analysis Plan. The permittee shall abide by the Quality Assurance Form (Attachment F) of this permit. This form must be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

c. The permittee shall assure that the waste analysis plan remains accurate and the analyses of any fluid sampled remain representative.

4. Continuous Monitoring and Recording Devices [OAC Rule 3745-34-38 (B)(2) and [OAC Rule 3745-34-56 (F)]. The permittee shall follow the deep well monitoring requirements provided in Attachment D of this permit. 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 also be maintained and operated to monitor the injected volume. The total injected volume for the well shall be recorded at least daily.

   During periods where the permittee is unable to continuously monitor the required parameters, the permittee shall implement its Ohio EPA approved deep well monitoring contingency plan. Nothing in the contingency monitoring plan shall relieve the owner or operator of their obligation to comply with requirements under applicable state and federal law or regulations.

5. Monitoring Wells. The permittee shall submit a ground water monitoring plan for approval within thirty (30) days of permit issuance. Ground water sampling and ongoing monitoring shall commence within ninety (90) days of plan approval. The plan shall describe a monitoring program capable of assessing whether the injection activity is impacting ground water quality in the lowermost underground source of drinking of water.

   The ground water monitoring plan shall include the proposed monitoring well location, proposed well construction diagrams and installation specifications, sampling and analysis procedures and sampling reporting procedures as listed in Attachment G of this permit. All ground water samples shall be analyzed for the constituents listed is Attachment G of this permit and for any other constituent(s) required by the Director.

   A copy of the approved ground water monitoring plan shall be kept at the facility and available for inspection.

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 permittee shall follow the protocol outlined in the Ohio EPA approved corrosion monitoring plan. At a minimum, the permittee shall report loss of mass, 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. The purpose of this study was 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 Coshocton, 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 Rule 3745-34-57 (K). The monitoring system specifications, reporting frequency, content, etcetera shall be established in a monitoring plan to be submitted to the Director for approval.

c. If the Director determines that injection activities at the subject site may be inducing seismic activity capable of risk to human health and the environment, the permittee shall immediately suspend injection operations upon written notification from the Director. Injection would not be authorized to resume unless the Director indicates in writing that it is acceptable to do so based on the evaluation of the seismic data.

E. REPORTING REQUIREMENTS (OAC Rules 3745-34-38 and 3745-34-58)

1. Monthly Reports. The permittee shall submit monthly reports to the Director containing, at a minimum, all of the following information:

a. Results of the monthly injection fluid analysis specified in permit condition Part II (D) (2).
b. Daily and monthly average values for injection pressure, flow rate and volume, annular pressure, and temperature of the combined waste stream.
c. Daily and monthly maximum and minimum values for injection pressure, annulus pressure, and flow rate of the waste stream.
d. Daily minimum differential pressure.
e. The combined monthly average flow rate for all wells.
f. The results of continuous monitoring of injection pressure, annulus pressure, flow rate and injectate temperature required in permit condition Part II (D) (4). These data shall be digitized and submitted on a single graph using contrasting symbols or colors for annulus pressure, injection pressure, flow rate and injectate temperature.

g. Total fluid volume of the combined waste stream injected daily, monthly, and the cumulative volume of fluid injected for the life of the well.
h. Date, time and volume of annulus fluid addition to or removal from the annulus system.
i. Annulus sight glass level readings noted daily at a specified time.
j. For each daily minimum and maximum injection rate reported, list the corresponding injection pressure and annulus pressure occurring during the time the well was operating at that minimum and maximum rate.
k. A listing of the duration and cause of any non-operating period for the well during the month.
l. Any procedures conducted at the injection well other than routine operational procedures.
m. Daily determinations of (injectate) pH, including monthly maximum and minimum values.
n. Determinations of injectate specific gravity a minimum of every four (4) hours.
o. Any noncompliance with conditions of this permit, including but not limited to:

   i. A description of any event that violates operating parameters for annulus pressure, injection pressure or annulus/injection pressure differential as specified in this permit; or
   ii. A description of any event which triggers an alarm or shutdown device required in Part II (C) (6) of this permit, accompanied by a description of the response taken for each event.

2. Quarterly Reports [OAC Rule 3745-34-58]. The permittee shall report all of the following each calendar quarter:

   a. Results of the continuous corrosion monitoring system and an interpretation of the results, as stipulated in Part II (D) of this permit, within fifteen (15) days after the end of the quarter;
   b. Results of ground water monitoring, and an interpretation of the results, as specified in an approved ground water monitoring plan, required in Part II (D) (5) of this permit, within fifteen (15) days after the end of the quarter.

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 the permit. Field log copies shall be made available the day of any geophysical well logging at the request of the Director or the Director's authorized representative. 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 pressure buildup monitoring data and analysis, 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 of the injection zone 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. 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 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 adoption of the plan, the permittee is required to submit to the Director a revised executive summary of the plan.

Attachment A

CLOSURE AND POST-CLOSURE PLANS AND COST ESTIMATES

I. Closure and Post-Closure Plans

II. Cost Estimates for Closure and Post-Closure

Attachment A

I. Closure and Post-Closure Plans

I.A.0 Mechanical Integrity Testing

At a minimum, an annular pressure test and Radioactive Tracer Survey (RTS) will be conducted on both wells to confirm the mechanical integrity of the wells prior to closure. Gauges used in these annulus pressure tests will be sensitive to changes equal to one-half of 1 percent of full scale readings. A temperature survey and/or cement bond log may also be run at the direction of the Director.

I.A.1 PLUG AND ABANDONMENT PLAN

Sections I.A.2 and I.A.3 outline the proposed plugging and abandonment procedures for the two Class I injection wells. Should it become necessary to make significant revisions to the method of closure described in the closure plan, Buckeye Brine will submit proposed changes to the Director of the Ohio EPA at least sixty (60) calendar days before closure, unless a shorter period of time is approved by the Director. Cementing will consist of three separate cement plugs, using Class H cement (or equivalent).

I.A.2 Plug and Abandon Well Adams No.1

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activities.

b. Perform APT and RAT log.
c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks.

d. Remove tree and install blow out prevention (BOP) equipment.

e. Release ASi-X mechanical packer and circulate annular fluid from well with 230 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).

f. Pull and lay down the ~5824' of 4-1/2" 10.5 lbs./ft. injection tubing and packer. Remove 4-1/2" tubing from site. Unload approximately 7,300 ft. of workstring onto pipe racks.

g. Run other logs if needed.

h. Make up a sliding valve cement retainer to set in 7" 23 lb./ft. casing on workstring. Tally workstring while running into well. Set cement retainer at bottom of casing +/- 5825'.

i. Mix and pump 310 sacks of Class A cement (yield 1.18 cf/sack) down the workstring tubing. Squeeze approximately 280 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 10 sacks of cement remain in tubing. Unstring from retainer (this action closes the sliding valve which removes the hydrostatic pressure from below the retainer) and spot remaining cement on top of retainer. Pull tubing to approximately 5620 ft. and reverse circulate until returns are clean. Trip out of hole with retainer stinger. Trip in hole with open-ended tubing. Wait for cement to harden a minimum of 8 hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5630 ft. Pressure test casing to 500 psi for 30 minutes.

k. Pull out of hole with work string, laying down joints until ~1100 ft. of workstring remains in the well and, mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 950 ft. BGL and reverse circulate until clean returns. Trip out of hole standing workstring back in derrick. Wait for cement to harden a minimum of eight hours.

l. Trip into hole and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 995 ft. Pressure test casing to 500 psi for 30 minutes.

m. Pull tubing up less than one joint and spot collar on rig floor mix and pump 150 sacks of Class A cement down workstring and circulate cement to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as workstring is removed the cement will fall downhole until all pipe is removed, approximately 38'. Pump cement remaining in pump truck into casing to raise level and washout pump truck with fresh water.

n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.

o. Rig down and move out workover rig and equipment.

p. Clean and level location. Submit required plugging reports

The closure report will certify that the well was closed as outlined in this plan, or where actual closure differed from this plan, a written statement specifying the differences between this plan and the actual closure will be provided. If both Buckeye Brine's injection wells are closed at the same time, Buckeye Brine will submit one report for both closures.

I.A.3 Plug and Abandon Well Adams No.3

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activity
b. Perform APT and RAT log.
c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks
d. Remove tree and install blow out prevention (BOP) equipment.
e. Release ASi-X mechanical packer and circulate annular fluid from well with 275 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).
q. Pull and lay down the 5917' of 4-1/2" 10.5 lbs./ft. injection tubing and the packer. Remove 4-1/2" tubing from site. Unload approximately 7,100 ft. of workstring into pipe racks.
f. Run other logs if needed.
g. Make up a sliding valve cement retainer to set in 8 5/8" 36 lb./ft. casing on workstring. Tally workstring while running into well. Set cement retainer just above packer at 5910 ft. BGL.
h. Mix and pump 325 sacks Class A cement (yield 1.18 cf/sack) down the tubing. Squeeze approximately 320 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 5 sacks of cement remain in tubing. Unstring from retainer, this closes the valve and relieves hydrostatic pressure under retainer, and spot remaining cement on top of retainer.
i. Trip out of hole with retainer stinger. Trip in hole with open-ended tubing. Wait for cement to harden a minimum of 8 hours.
j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5895 ft. Pressure test casing to 500 psi for 30 minutes.
k. Pull out of hole laying down workstring tubing until 1100 ft., of tubing remains in the well then mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 910 ft. BGL and reverse circulate until clean returns. Trip out of hole. Wait for cement to harden a minimum of 8 hours standing workstring tubing back in derrick.
l. Trip into hole with tubing and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 919 ft. Pressure test casing to 500 psi for 30 minutes.
m. Pull tubing up one joint or less and spot collar on rig floor and mix and pump 150 sacks of Class A cement and pump cement down tubing to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as the workstring is removed the cement will fall downhole until all pipe is removed, ~ 45'. Pump cement remaining in pump truck into casing to raise the level and washout pump truck.
n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.
o. Rig down and move out pulling unit and equipment.
p. Clean and level location. Submit required plugging reports.

Attachment A

II. Closure and Post-Closure Cost Estimates

UIC Class I Waste Injection Well
Estimate of Closing Costs (Plugging and Abandonment)
Note: These calculations are based on costs obtained in 2017

Identification		
Date	4-Dec-17	
Permit Number	Well # Adams 1	
Permittee	Buckeye Brine	
Job Title	UIC Permit Application	
Well Data		
Plugging method (four plugs or cement filled)	0	0-Plugs or 1-Filled
Avg Well Inside Diameter (in)	6.366	
Top of Inj Interval (feet)	5,832	
Plugged Back Total Depth (feet)	7,305	
Hazardous Waste Well	0	0-No or 1-Yes
Calculated Mud Vol (bbl)	295	
Calculated Cement Vol (ft3)	394	
Costs		
Consultant		
Preclosure and postclosure work	$8,500	
Wellsite @ $1,350/day	$13,500	
Testing (MIT, pressure fall-off)	$55,100	
Workover rig, etc.	$30,000	
Mechanical bridge plug	$8,800	
Mud ($15/bbl)	$4,425	
Cement ($40/sack)	$13,133	
Welding	$1,000	
Extra Charge for haz waste well	$0	
Consultant mark-up (12%)	$13,495	
Subtotal	$147,953	
Contingency (20%)	$29,591	
Total	$177,544	
Financial Assurance Amount (2017 dollars)	$178,000	
Financial Assurance Amount Adjusted for Inflation to 2017 Dollars	$178,000	
Adjustment for inflation to 2017 Dollars	$0	
TOTAL FINANCIAL ASSURANCE	**$178,000**	

Financial Assurance for Closure and Post Closure

Table III.E Plugging and Post Closure Cost Rev 1 10/17/2017

	Adams # 1	Adams # 3	Cost at time second well plugged	Total
Injection Well Plugging Cost	$147,953	$152,779		$300,732
Post Closure				
Sampling and analysis of GW 4 Qtrs			$8,000	$8,000
Pressure falloff modeling and report			$2,500	$2,500
Plug monitor well				
Cut off casing and weld ID plate	$3,500	$3,500		$7,000
Final Report and Deed Record			$2,500	$2,500
Monitor Well Plugging Cost			$3,000	$3,000
Total Estimated Cost for both wells including post closure				$323,732
Contingency (20%)				$64,746
Total				$388,478

Attachment B

Geotechnical Information

I. Geology Description

II. Seismic Discussion

The data provided in this attachment was extracted from the UIC permit to operate applications. This attachment represents a condensed summary.

Attachment B

I. Geology Description

11.A REGIONAL GEOLOGY

II.A.1 REGIONAL STRATIGRAPHY

PRECAMBRIAN

Based on drill cuttings in the Area of Review (AOR), as well as other basement test within a 25-mile radius of the AOR, the Precambrian in the vicinity of the area of review (AOR) has been determined to be granitic in composition. Drilling experiences and wireline logs suggest that the upper portion of the Precambrian may be present as a so-called "granite wash," either a highly weathered and/or detrital form of the native rock that is relatively easy to drill. The paleotopography of the Precambrian surface is typically irregular due to a combination of differential erosion and mild tectonics. Although relief of up to 300 ft. is possible, it is more typically of a very low scale. Wireline log control is too thin to put much detail to the surface form of the Precambrian in the AOR, but seismic data in eastern Ohio routinely shows such a surface.

II.A.1.a CAMBRIAN PERIOD

Mt. Simon/Basal Sand

The Mt. Simon is the lowermost of the Cambrian units. It ranges in thickness from about 350 ft. in western Ohio and thins to about 100 ft. in eastern Ohio. In western Ohio it is a fine to coarse-grained quartz sand with a moderate to light carbonate cement, and commonly possesses moderate to excellent porosity (to 15%) and low to high permeability (0.1-10,000 mD). On the eastern edge of Ohio the Mt. Simon is a very fine-grained quartz sand with a robust carbonate cement. The net sand thickness in a 100 ft. interval is commonly less than 40 ft. Porosity as determined from wireline logs is typically less than 10%. Permeability is low, as determined from tests and observations while drilling. It has been offered by some that the sand as it exists on either side of the State is not the same formation. Accordingly, the lesser sand in the eastern part of the State is sometimes informally referred to simply as the "basal sand."

In eastern Ohio where the unit is noticeably finer textured and contains a higher percentage of associated dolomite, it may be alternately referred to as the "basal sand."

Rome Dolomite

What is called the Rome dolomite (Janssens, 1972) in eastern Ohio is a massive, white to light gray, micro- to finely crystalline section of 350-750 ft. thick dolomite. It is considered as having two identifiable parts, a lower arenaceous dolomite section and an upper pure dolomite section. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone. As such the basal Rome is an arenaceaous dolomite with a fine-textured sand content that decreases upward. Some sandstones may be included. The upper portion of the Rome may be sucrosic in parts of the section, but is generally considered to be non-porous. The upper boundary of the Rome is considered an unconformity surface.

Conasauga Shale/Dolomite

Throughout much of the literature the Conasauga has been identified as a shale, though it is in fact a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lower part of the unit. Across most of central and eastern Ohio the unit is 100-150 ft. thick, but accumulations of up to 400 ft. are present in south-central Ohio. In central Ohio, which is the effective western limit of the Conasauga; the upper portion of the unit grades laterally into the Kerbel (arenaceous dolomite).

Lower Copper Ridge Dolomite

The Lower Copper Ridge is contained within a 50-500 ft. thick interval across eastern Ohio, being thinnest in the northeast corner of the State and thickest in south-central Ohio. It is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. Locally, portions may be sucrosic and have minor porosity, and the unit commonly makes fluid while drilling.

Copper Ridge "B" Zone

The informally named Copper Ridge "B" ranges in thickness from about 200 ft. in the northeast corner of the State to about 75 ft. across the southern part of the State. Across most of its range the section comprised of argillaceous dolostones and gray shales; the basal portion may be arenaceous or contain shell fragments, suggesting possible deposition on an erosional surface. In central Ohio the unit truncates unconformably against the regional Knox unconformity. The "B" zone may be oil and gas production where the "B" zone is encountered within the subcrop zone and is contained in an erosional remnant. The "B" zone has also been productive in Knox County where hydrocarbon is structurally trapped.

Copper Ridge Dolomite

The Copper Ridge is present across eastern Ohio as a 100-350 ft. thick unit that is composed of a relatively pure microcrystalline to finely crystalline dolomite with a minor clay content. The upper portion is arenaceous and transitional into the overlaying Rose Run sandstone. The Copper Ridge subcrops against the regional Knox unconformity in central Ohio. It may constitute an excellent oil and gas reservoir where the rock occurs in paleo-erosional remnants that underwent porosity enhancement due to subaerial exposure.

Rose Run Sandstone

The Rose Run sandstone is most widely recognized across eastern Ohio as a dolomite containing a series of readily identifiable interbedded sand bodies. It ranges from about 50-125 ft. in thickness. At its western edge the Rose Run subcrops unconformably against the regional Knox erosional surface. The Knox unconformity may have positive relief that is vested in small (10-20 ac.) paleo-erosional remnants whose height is commonly on the order of 20-80 ft. Within its subcrop zone, Rose Run sands that are contained in the high-standing remnants were exposed to prolonged sub-aerial conditions that degraded the dolomitic cement in the sandstone, resulting in a substantial enhancement of porosity and permeability. Surrounded and/or overlain by younger impermeable Ordovician shale and limestone, such remnants became excellent oil and gas reservoirs. Below the grade of the Knox erosional surface or downdip from the subcrop, the porosity and permeability of the Rose Run is modest at best and, lacking any definable trapping mechanism, is barren of hydrocarbon except in the unusual circumstance of a closed structure.

II.A.1.b ORDOVICIAN PERIOD

Beekmantown Dolomite

In a manner similar to that of the underlying Rose Run sandstone, the Beekmantown is present across eastern Ohio and at it western edge is truncated against the regional Knox unconformity. This truncation occurs east of the AOR. The Beekmantown is a dense, white to light gray, micro- to very finely crystalline dolomite. Certain zone are especially prone to porosity development where the rock is contained within an erosional remnant; under those conditions it has been successfully exploited for gas production.

Wells Creek and Lower Chazy Shales

Considerable confusion attends the nomenclature of the Wells Creek and Lower Chazy shales, which are sometimes collectively or singly referred to as the Glenwood. As discussed herein, the two are differentiated on the basis of color and lithology. The approximately 30 ft. thick Lower Chazy is a dense, micritic, argillaceous limestone with interbedded gray shale. The underlying Wells Creek ranges from 30-170 ft., thickening progressively to the east. It is composed of a hard, dense, micritic, argillaceous dolomite with interbedded shale, the whole appearing light gray or in shades of green or pale blue. Both units are effective barriers to fluid migration, especially for oil and gas contained in pre-Knox erosional remnants (e.g., Rose Run and Beekmantown).

Gull River Limestone

The 45-70 ft. thick Gull River is composed of a uniformly dense and pure, impermeable micritic limestone. Across most of eastern Ohio the Gull River has a distinctive caramel color.

Black River Limestone

The Black River has a maximum thickness of about 750 ft. along the eastern edge of Ohio, thins to about 450 in central Ohio, and more or less maintains that thickness across the remainder of the State. Lithologically, it is similar to the underlying Gull River. Most of the unit is a brown or dark gray-brown, dense, impermeable micrite. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale.

Trenton Limestone

The Trenton Limestone is present across all of Ohio, ranging in thickness from about 300 ft. in the northwest part of the State to about 40 ft. in west-central Ohio. Depending on locale, it is various shades of white, light to dark gray, and brown limestone, and is typically fossiliferous. Clay and thick black shale may be included. Where fractured and subsequently dolomitized, it can be an excellent oil and gas reservoir, as was the case for the giant Findlay-Lima-Peru field in western Ohio and eastern Indiana.

Point Pleasant and Utica Shales

These two units are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of up to 240 ft. Their specific lithologies range from dark brown to black argillaceous limestone to calcareous shale. Fossil shell beds may be present, and the Utica, in particular, can be quartz rich. Because of the included carbonate and quartz, the rocks are relatively brittle and respond very well to hydraulic fracturing that is necessary for extracting hydrocarbons from these organic shales.

Cincinnatian Shale

The Cincinnatian is an approximately 500 ft. thick along the western margin of the State and about 2500 ft. thick along Ohio's southeastern border. In western Ohio the Cincinnatian is exposed at the surface as a series of thinly interlayered, fossiliferous gray shales and argillaceous limestones. In eastern Ohio few wells are drilled deep enough to reach the Cincinnatian. Because it has no known commercial value, little attention has been paid to the unit and it remains poorly understood and poorly described.

Queenston Shale

The Queenston is an approximately 400 ft. thick, red, silty shale indicative of an emergent landscape at the end of the Ordovician. It transitions downward into the Cincinnatian series of shale. The upper surface of the Queenston is erosional, and in certain locales it exhibits considerable relief, enough in instances to preclude deposition of the overlying Medina or even part of the Clinton sandstones. Having no commercial value, the Queenston is rarely given more than a cursory look, and is considered to be impermeable, non-reservoir rock.

II.A.1.c SILURIAN PERIOD

Medina Sandstone

The Medina is a thin (<20 ft.), silty to fine-grained transgressive, quartz-cemented sandstone deposited on the Queenston erosional surface. Its range is limited to the eastern third of Ohio, and it thins westward to a pinchout. Its thickness may be influenced by the paleotopography of the underlying Queenston shale. In certain restricted areas the Medina is well developed with regard to porosity and permeability; it may produce oil and gas where such sands can be encountered in an updip pinchout. Otherwise, in most areas the sand is too finely textured and lacks sufficient porosity to be considered reservoir rock.

Cataract Group/Clinton Sandstone

The Cataract Group includes the informally-termed Clinton sandstone and the gray shales above and below. In eastern Ohio the Clinton sandstone has been the backbone of the local oil and gas industry for most of a century. The unit has a 50-200 ft. range of thickness, with thickness increasing to the east. The sandstone portion of the Clinton itself is developed as a series of white and/or red, interlayered, very fine-grained to silty quartz sands with a silica cement. Porosity and permeability is low, not often exceeding 10% and 10 mD, respectively. In the western two-thirds of Ohio, the Clinton is reduced to an unremarkable gray shale and is difficult to discern from the underlying Ordovician shale.

Dayton (aka Packer Shell) Dolomite

The Dayton Formation is identifiable across Ohio. Depending on locale, the unit appears as one to three thin, transgressive lenses of micro- to coarsely crystalline, slightly fossiliferous dolomite that occur predominantly in white or shades of gray. A single lens may be from 5 to 40 ft. in thickness, and multiple lenses can be as much as 60 ft. in the aggregate. Where multiple lenses are present, the interlayered calcareous shale is gray and blocky. Additional evidence of the prevailing shallow water environment is given by the common appearance of a thin, distinctively red, hemitiic limestone oolite at its base. The common "Packer Shell" moniker for the Dayton Formation derives from century-ago cable tool drillers who used the dolomite bed(s) as a casing seat when drilling to the Clinton sandstone in eastern Ohio.

Rochester Shale

The thickness of the Rochester shale expands from about 100 ft. in the central portion of Ohio to about 300 ft. along the Ohio River on the southeastern border. The Rochester shale is a mix gray shale and dense, blocky, red and green marls, the latter occurring primarily in the lower half of the unit.

Lockport Dolomite

The Lockport, more commonly referred to as the Newburg, is an accumulation of carbonates that may range from dolomite to limestone, the dolomite mineralogy predominating. The Lockport is notable for the small (commonly 10-100 ac.) reefs contained within, these mainly in the northeastern part of the State. Where such reefs are encountered, they typically produce copious amounts of water and, on occasion, some hydrogen sulfide gas; oil and gas is less commonly encountered. Because the reefs are very porous and highly permeable, they are not infrequently utilized as small-volume disposal reservoirs. In the southern part of the State the Lockport contains the north-south trending, gas productive Williamsport sandstone that is interpreted to be a bar deposit. The Lockport is about 300 ft. across most of eastern Ohio, but thins to about 200 ft. in the northeastern corner of the State, and up to about 350 ft. in southeastern Ohio.

Salina Dolomite

The Salina ranges widely in thickness from about 300 ft. in western and central Ohio to about 1200 ft. along the Ohio River in southeast Ohio. It is composed of a sequence of dolomite and anhydrite that contains a minor amount of thin gray shale. In the eastern third of the State, salt is contained within the Salina as one or more laterally expansive and identifiable beds. Those salt beds thin and diminish in number to the west.

II.A.1.d DEVONIAN PERIOD

Bass Island and Helderberg Limestones

The 190 ft. thick Bass Island and Helderberg units are the basal members of the Devonian sequence. Both have a limestone-dominant lithology, and both contain thin (to 15 ft.) dolomite sections. The dolomites may be sucrosic and/or brecciated. The dolomite portions may have minor porosity, but rarely yield any fluids, and never produce oil or gas in the AOR. Both units are bounded above and below by unconformities.

Onondaga Limestone

As discussed herein, the Onondaga, informally referred to as the Big Lime, also includes the Oriskany sandstone, the Helderberg limestone, and the Bass Island dolomite. At their western limit where they occur at the surface, the carbonates are an important industrial mineral. The included Oriskany sandstone occurs in the eastern quarter of Ohio. It is bounded above and below by unconformities and pinches out to the west. The Oriskany has commercial value as a producer where gas and oil can be trapped in a structurally advantaged updip pinchout; lateral variations in porosity and permeability may also contribute to entrapment.

Olentangy Shale

As described herein, the approximately 140 ft. thick Olentangy is composed of a series of gray and black shales, portions of which may be calcareous or include thin beds of limestone. Within the AOR and its vicinity, none of the black shales contained in the Olentangy have a high enough total organic carbon (TOC) content to warrant consideration as hydrocarbon reservoir, though they may have generated some hydrocarbon that found its way to other reservoirs above or below.

Ohio Shale

The Ohio shale as discussed herein is about 1400 ft. thick and includes, from bottom to top, the Huron, Chagrin, and Cleveland members. Except for portions of the Huron member that contains some low TOC black shale, the interval is composed of gray shale.

Berea Sandstone

The Berea sandstone is omnipresent across eastern Ohio and ranges in thickness up to 125 ft. in northeast Ohio where it is exposed at the surface and mined as building stone. It is composed of a silty, very fine-grained, mechanically cemented pale brown to gray sandstone with modest porosity (to 10%) and permeability. It produces marginal quantities of oil and gas where favorable structural and stratigraphic conditions coincide with good reservoir conditions.

II.A.1.e MISSISSIPPIAN PERIOD

Sunbury Shale

Referred to by cable tool drillers as the "Coffee shale" for its distinctively rich brown color, the 0-40 ft. thick Sunbury shale is organic, slightly silty, and breaks easily under the drill. Although it does not produce oil or gas by itself, it is at least one source for the oil and gas trapped in the underlying Berea sandstone. Its range is the eastern third of Ohio

Cuyahoga Shale

Locally the approximately 150 ft. thick Cuyahoga is composed entirely of non-porous, non-permeable gray shale. Elsewhere in the State, particularly to the southeast, the unit may be silty in part, or even contain distinct and identifiable siltstones that are capable of delivering marginal quantities of oil and gas.

II.A.1.f UNDIFFERENTIATED MISSISSIPPIAN AND PENNSYLVANIAN CLASTICS

In eastern Ohio the Mississippian and Pennsylvanian section above the Cuyahoga shale is comprised of alternating layers of shale, siltstone, and sandstone. Cut-and-fill features abound. The Pennsylvanian contains multiple beds of mineable coal. Being the youngest and shallowest of formations in eastern Ohio, they were among the earliest developed for oil and gas production. Their heyday had passed by the time wireline logging was introduced to the Appalachian Basin, and good wireline coverage over these units is thin. Most of the good detailing of the Mississippian and Pennsylvanian rocks has been an outgrowth of mapping associated coal beds.

II.A.2 - Characteristics of the Injection and Confining Zones

II.A.2.a - Injection Zone

The injection zone, being considered that portion of the wellbore below the injection string packer that is exposed to injected fluid, is the entirety of the openhole section. In the Buckeye Brine No. 1 Adams, the packer is set in the base of the Black River limestone at a depth of 5898 ft. Accordingly, the injection interval includes, from top to bottom, the Gull River, Glenwood shale (Lower Chazy and Wells Creek), Rose Run sandstone, Copper Ridge dolomite, Copper Ridge "B", Lower Copper Ridge dolomite, Conasauga dolomite and shale, Rome dolomite, and the Mt. Simon sandstone.

The total depth in the No. 1 Adams is 7305 ft. and cut an estimated 8-10 ft. into the Precambrian. The thickness of the injection interval from the base of the packer to total depth is ostensibly 1472 ft. However, prior to any testing, an approximately 20 ft. thick cement plug was set over the Precambrian, reducing the injection interval to 1452 ft.

The discussion that follows presents the general characteristics of each unit. So as to not mire the dialogue in details of possible lithology changes across the breadth of the State, these comments are generally meant to imply a 25-miles radius beyond the AOR, unless otherwise noted.

The Gull River is a regionally recognized unit that is composed of a dense, non-porous, non-permeable, micritic to microcrystalline limestone.

In a manner similar to the Gull River, the underlying Lower Chazy and Wells Creek units (commonly referred to collectively as Glenwood) are dense, non-porous, non-permeable rocks with excellent lateral continuity. Whereas the Lower Chazy is an argillaceous limestone with included shale, the Wells Creek is an argillaceous dolomite with included shale. Both can be easily traced in any direction.

Within 25 miles to the west, both the Rose Run and Copper Ridge terminate unconformably or are otherwise reduced by erosion against the regional Knox unconformity. Elsewhere, north and south, and to the east, each is laterally continuous and is of more or less predictable, if not constant, character. The Rose Run is dominated by non-porous dolomite, but includes up to five identifiable sand bodies that produce oil and gas under favorable conditions, particularly where erosional remnants of the Rose Run poke into the overlying Glenwood shale so as to ensure lateral sealing against fluid migration.

Downdip (east) from the AOR, the Rose Run sands become finer textured and better cemented, substantially reducing any reservoir qualities. The upper portion of the Copper Ridge is arenaceous and, like the Rose Run, may produce oil and gas in its subcrop zone to the west. Generally the lower portion of the Copper Ridge has little or no porosity and gives no evidence of permeability.

The Copper Ridge "B" is distinctive on logs and on samples for its high gamma-ray signature due to included clay and shale content. Within the area of description, the Copper Ridge is insufficiently porous to offer viable reservoir opportunities, despite wireline logs that in some instances generate an optimistic view of the unit.

Encountered as a massive, clean dolomite, the Lower Copper Ridge (LCR) is easily recognized in Coshocton and adjacent Counties. The upper portion of the LCR is commonly sucrosic, and well logs may indicate some manner of porosity. During drilling, the LCR commonly gives up at least some measure of fluid, validating observations of texture in the cuttings and values generated by the well logs. In local testing the unit has shown sufficient porosity and permeability to receive injected fluids, but it is not known if this trait is constant through Coshocton and adjacent Counties.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. These sands are commonly capable of receiving at least some injected fluid, but not enough wide-ranging penetrations and testing to determine the extent of reservoir conditions in these sandstones. The upper part of the Conasauga is a dense, argillaceous dolomite that is not considered to have reservoir potential.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Porosity development may be poor to excellent, but is invariably subtle and not easily or accurately quantified with wireline logs. The best porosity is developed within the uppermost 100 ft. of the unit and is linked to an end-of-Rome erosional surface.

The Mt. Simon is ubiquitous across Ohio, but its character changes from west to east. Along the western edge of the State it is a fine to coarse-grained sand, typically with good porosity and permeability. To the east the sand becomes increasingly fine, the degree of cementation increases markedly, and reservoir quality suffers. In eastern Ohio, Mt. Simon penetrations can generate favorable-appearing porosity on wireline logs that fails to translate into viable reservoir (Wickstrom, et al., 2011).

<u>II.A.2 b - Confining Zone</u>

The confining zone is considered to be that portion of the wellbore above the injection string packer. In this application the confining zone is approximately 2000 ft. thick and consists of 650 ft. of Ordovician limestones and 1400 ft. of Ordovician shale. The carbonate section is frequently penetrated in the quest for oil and gas, is well documented by wireline well logs, and is well understood by drillers and geologists who attend the process of exploration drilling. The shale portion is familiar, but not extensively studied or reported.

The specific formations included in this confining zone, from bottom to top, are the Black River and Trenton limestones, and the overlying Point Pleasant, Utica, Cincinnatian, and Queenston shales.

The approximately 580 ft. thick Black River is a massive, uniformly dense, non-porous, non-permeable, micro- to very finely crystalline limestone. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale. Lateral continuity is excellent.

The uppermost carbonate unit in the Ordovician section is the approximately 60 ft. thick Trenton limestone. It is composed of a very fine to coarsely crystalline limestone, and is abundantly fossiliferous at the top, becoming less so toward the bottom. Portions of the unit may be argillaceous or contain very thin stringers of black shale. Lateral continuity is good, any variations being vested primarily in minor thickness changes.

The Point Pleasant and Utica shales are herein discussed together. Both are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of about 250 ft. Their specific lithologies range from argillaceous limestone to calcareous shale. Fossil shell beds may be present, particularly in the Point Pleasant. The Utica, in particular, can be arenaceous. Because of the included carbonate and quartz, the rocks are relatively hard. The hardness may present drilling problems, but it also provides for a rock that responds very well to the hydraulic fracturing necessary for extracting hydrocarbons. Lateral continuity is good and, absent any hydraulic or natural fracturing, the Point Pleasant and Utica are considered impermeable.

The Cincinnatian is an approximately 750 ft. thick section of gray shale. Because few wells are drilled deep enough to reach the Cincinnatian and because it has no known commercial value, little attention has been paid to the unit. It remains poorly understood and poorly described. Where the Cincinnatian has been reached by the drill, it yields no shows of any kind and is thus regarded as impermeable and barren of fluids. Lateral continuity is excellent.

The Queenston is an approximately 400 ft. thick red, silty shale. The boundary between the Queenston and the underlying Cincinnatian is transitional. Having no commercial value, the Queenston is rarely given more than a cursory look, but based on drilling observations, it is considered to be an impermeable, non-reservoir rock.

References cited:

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Sclucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio.

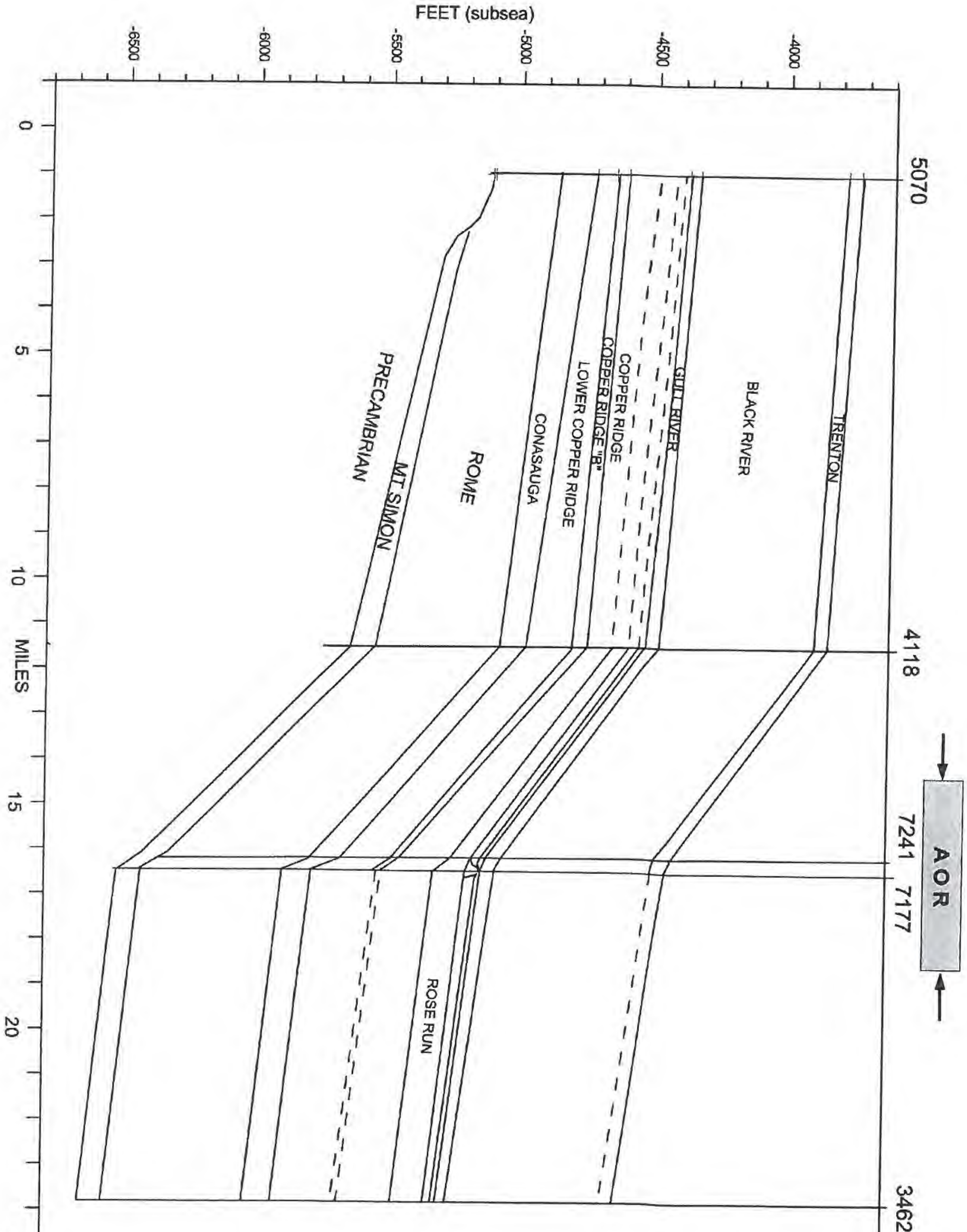


Figure II.A.3.02 - North-South structural section traversing the Area of Review and passing through the Buckeye Brine facility

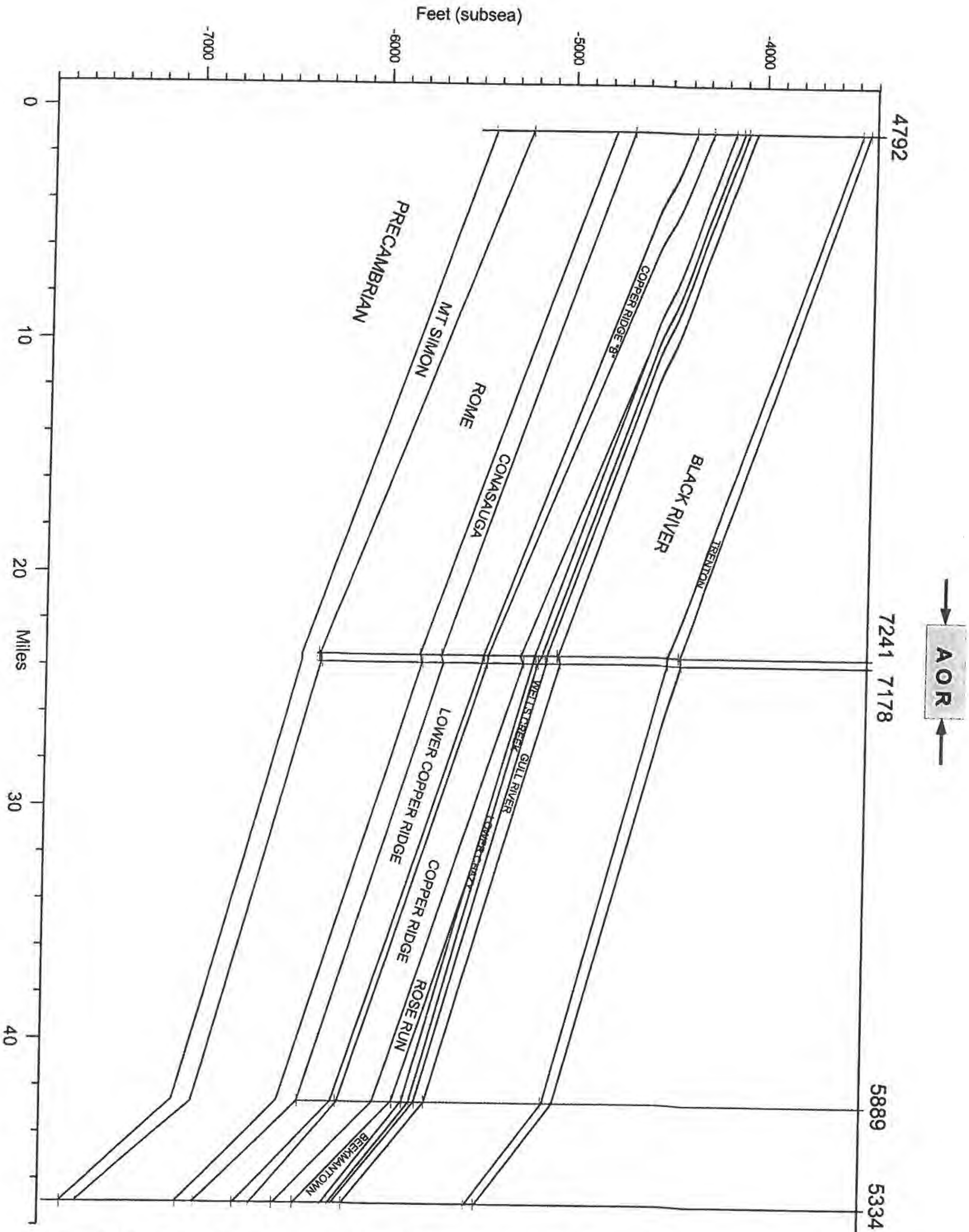


Figure II.A.3.03 - West-East structural section traversing the Area of Review and passing through the Buckeye Brine facility

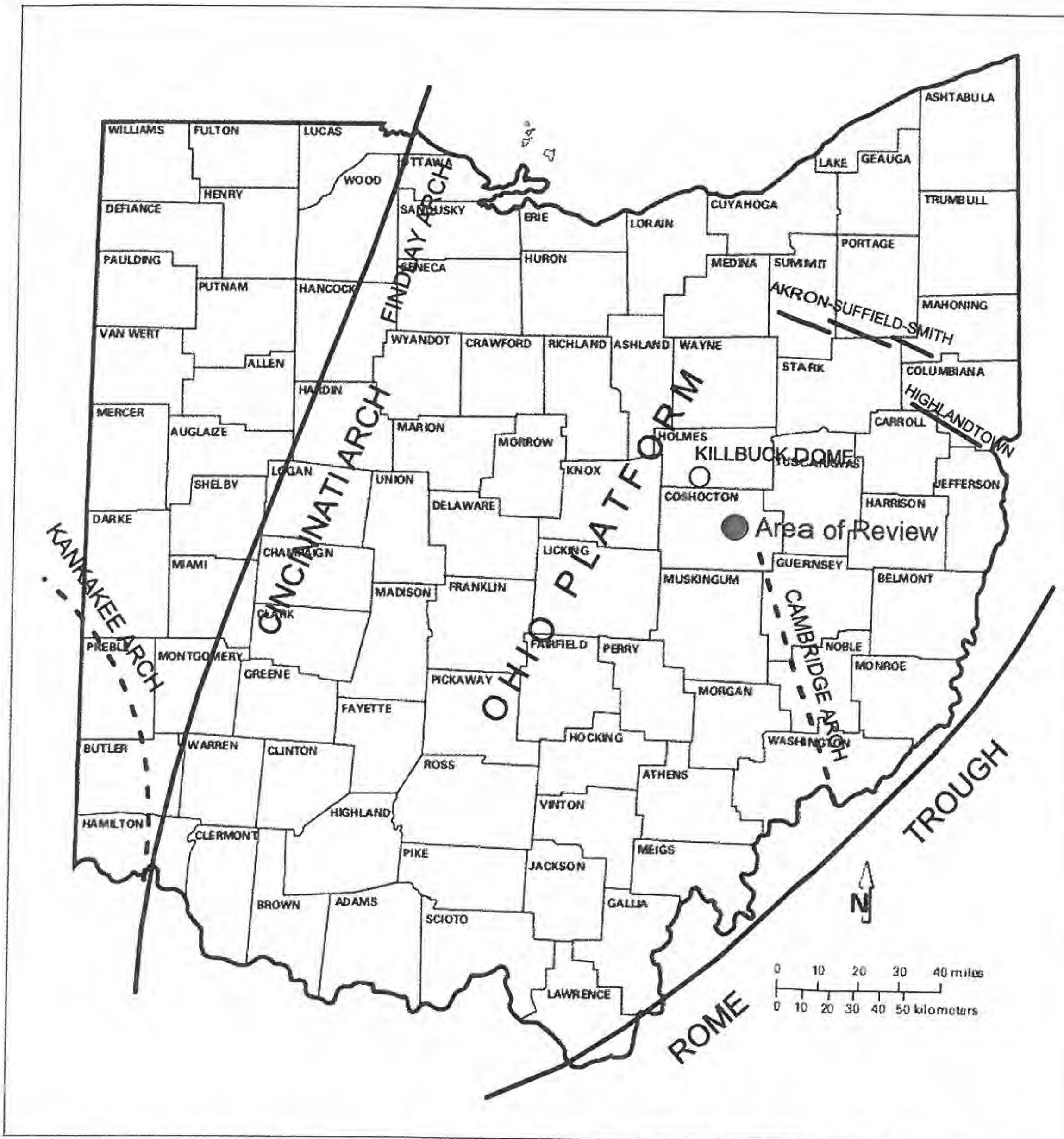


Figure II.A.4.02 Map showing key structural features on and bordering the Ohio Platform

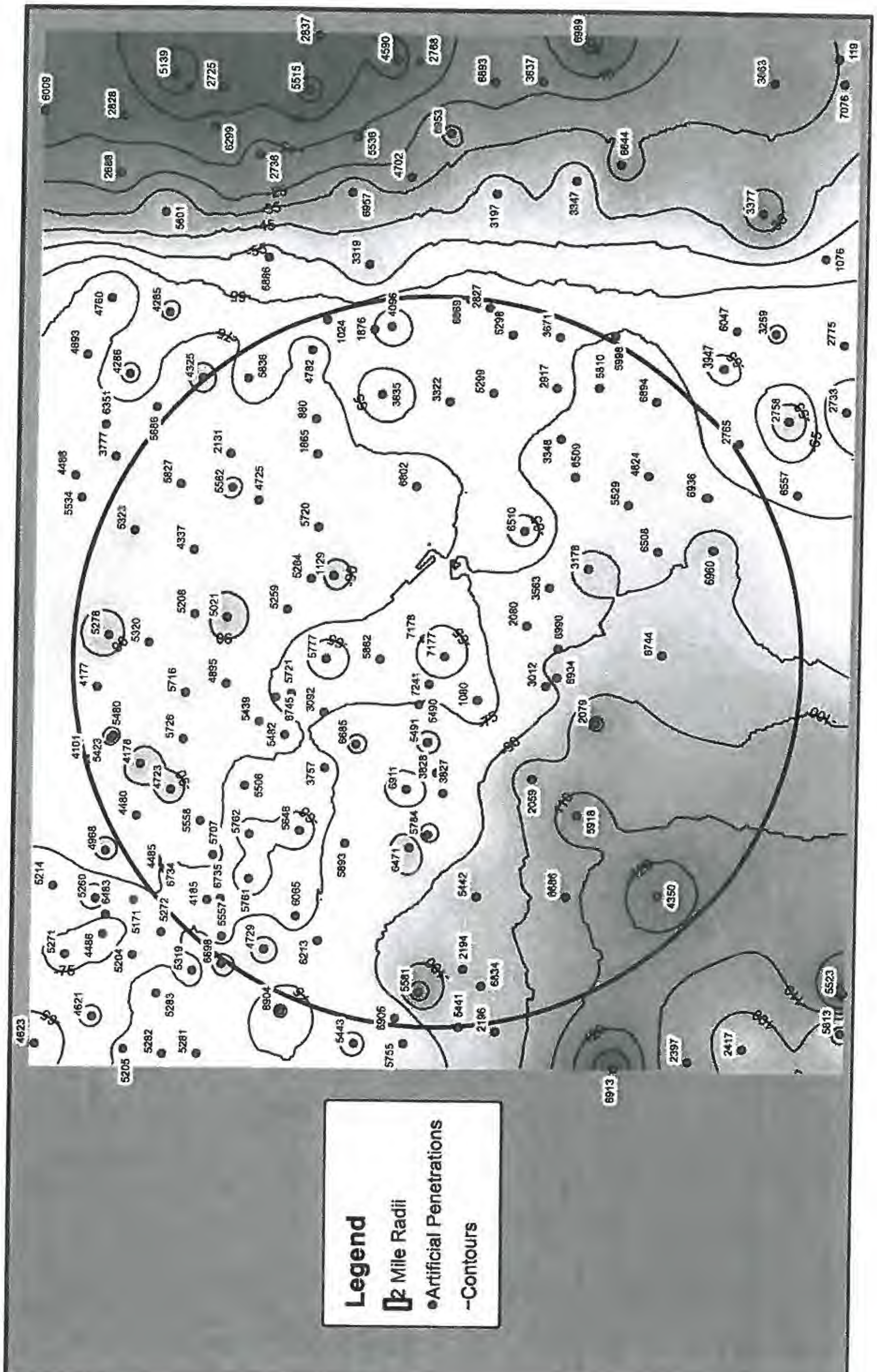


Figure II.A.4.03 - Structure map showing the manifestation of the Cambridge Arch on the top of the Berea sandstone

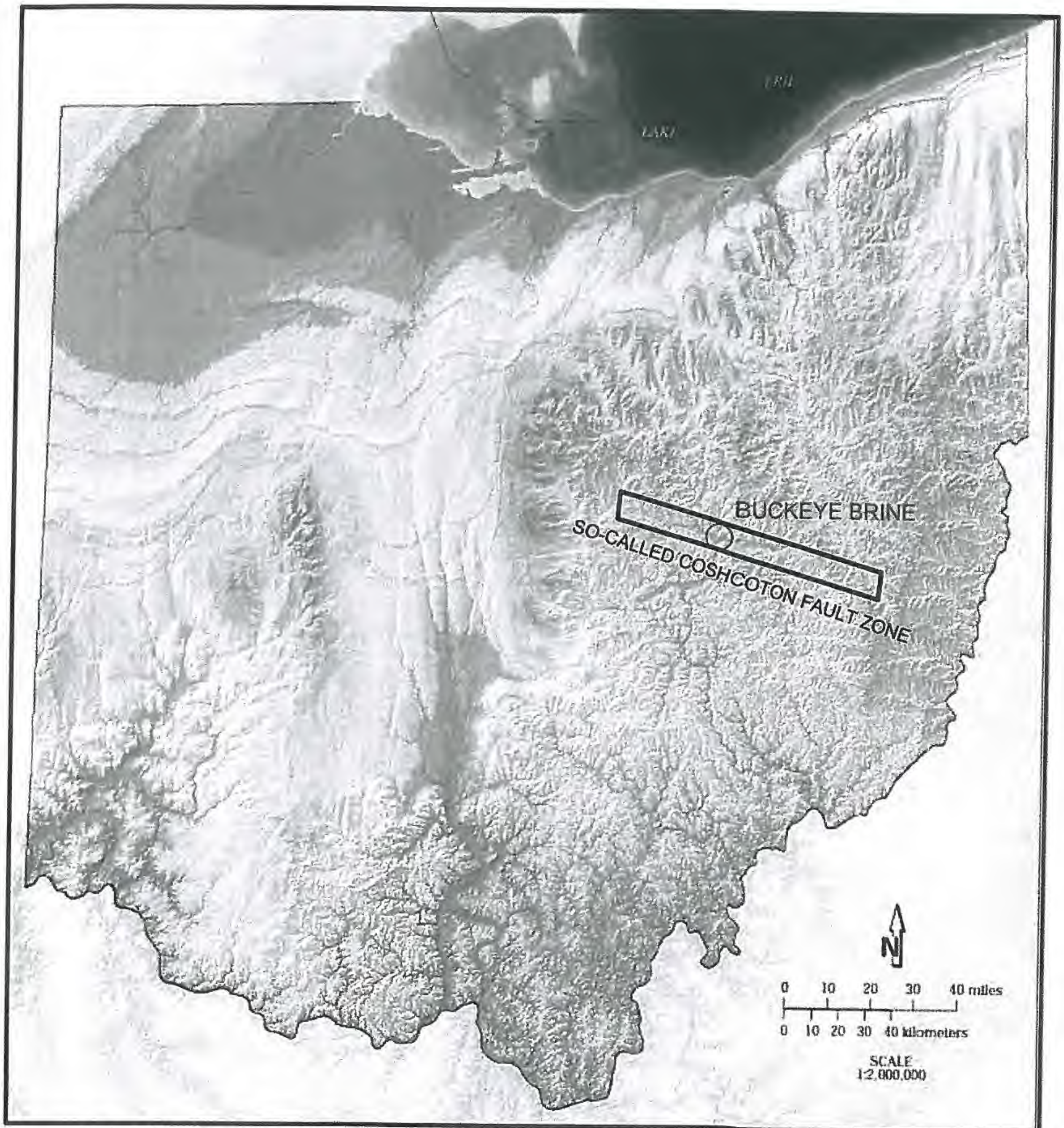


Figure II.A.4.04 - Shaded relief map by the Ohio Geological Survey shows the faint surface trace that is the basis for the Coshocton Fault Zone.

11.B LOCAL GEOLOGY

II.B.1. LOCAL PHYSIOGRAPHY AND BEDROCK

II.B.1.a. Physiography

Buckeye Brine's facility is 2 miles north of the city of Coshocton, and 0.6 miles north of the Tuscarawas River. Downstream from the facility, the smaller Walhonding River joins the Tuscarawas River on the north side of Coshocton where the two form the Muskingum River.

North of Coshocton, the local land surface is dominated by a flat, mile-wide incised valley that contains the meandering Tuscarawas River. Near the Buckeye facility the river is at an elevation of 740 ft. The valley and the lower slopes of the adjacent hillsides are cut into the Pennsylvanian Pottsville Group, and the hillsides themselves are topped with nearly a full section of Allegheny Group. On the north and south sides of the river, tributaries tend to be short. Lamborn (1954) described these tributaries as immature.

II.B.1.b Bedrock Geology

The Tuscarawas River has been incised into the Pennsylvanian Allegheny and Pottsville Groups, which have a combined thickness of about 300 ft. Total relief on the local topography is approximately 270 ft.

The hilltops on either side of the Tuscarawas River are topped with a nearly full section (140 ft. out of 150 ft.) of Pennsylvanian Allegheny shales, siltstones, and clays. The unit also includes Clarion, Kittanning, and Freeport coals. The Middle Kittanning has been mined from the surface and subsurface north of the Buckeye facility.

The river is cut into the Pottsville, and that same series of sediments form the bases of hills that border the valley. The lithology of the Pottsville is similar to that of the overlying Allegheny, both presenting a series of cyclothems. Above the valley floor, the Pottsville exposes the Brookville, Tionesta, Bedford, and Mercer coals, none of which have been mined locally.

An estimated 150 ft. of detritus and glacial outwash fill the valley floor, not counting the aforementioned terraces. On this basis it may be surmised that the river at one time had cut into Mississippian sediments.

Reference cited:

Lamborn, R., 1954, Geology of Coshocton County: Ohio Division of Geological Survey, 245 p. Plus Map.

II.B.2 LOCAL GLACIATON

Neither the Wisconsin nor Illinoian ice sheets advanced far enough south and east through Ohio to impinge on the AOR. In like manner, there is no evidence that either of those glacial events had a meaningful effect on pre-Wisconsin/Illinoian drainage patterns.

Meltwater from both events emplaced substantial outwash deposits in the Tuscarawas River Valley as far east as Newcomerstown, 10 miles east of the AOR. The most visible of these deposits form broad, 20-60 ft. high terraces on either side of the river, and the less obvious deposits constitute the mile-broad, flat expanse of river bed fill material.

Any possible evidence of the earlier Kansan or Nebraskan ice ages in eastern Coshocton Co. is generally considered too suspect to support declarative statements as to their character and effect.

II.B.3 Groundwater Resources and Lowest USDW

The deepest underground source of drinking water (USDW) is defined (<10,000 ppm TDS) by the U.S. EPA. In the Coshocton area and the Area of Review (AOR) this is based on work done by Vogel (1982), which cited the Black Hand sandstone as the base of the USDW. Matchen (2006), however, maps the Black Hand as an elongated sand body trending north-south and lying about 10 miles west of the (AOR) and this throws into question the precise stratigraphic identification of the USDW reservoir. Nonetheless, as later mapped by Riley (2012), the so-called Black Hand is cited as the deepest USDW and covers much of eastern Ohio. In the area of review, Riley's base of USDW lies at a depth of about 330 ft. from the surface (Fig. V.B.3.a-01 and Fig. V.B.3.a-02).

The depth to the USDW notwithstanding, culture in the AOR is largely confined to the valleys, where local, domestic water is supplied chiefly by shallow domestic wells drilled into the sand and gravel that fills the Tuscarawas River valley. Typically these wells are drilled and cased to a depth of 50-75 ft. and generate excellent yields that average about 35 gallons per minute (gpm). On its map "Yields of the Unconsolidated Aquifers of Ohio," the Ohio Division of Water Resources attributes these valley-drilled wells with potentials in excess of 500 gpm. Static water levels are about 25 ft. below grade. Although a few wells have been drilled to depths of over 100 ft., their yields and static levels are comparable to those of the shallower wells.

On higher ground, away from the valley, water may be obtained from perched sandstone aquifers contained within the Allegheny Group sediments. Yields and static levels are reported as being comparable to those encountered from the sands and gravel in the river valley.

To a lesser degree, municipal (Coshocton) water is supplied to certain larger public and private facilities such as the Coshocton Co. Regional Airport, and the Coshocton City and County golf course, the Coshocton Christian Tabernacle church, and retail establishments close by Rt. 36.

Drilling and completion records for domestic water wells are maintained by the Ohio Department. Natural Resources Division of Water and are available online. The most recently drilled wells are typically the most complete and accurate records. Wells that predate permit requirements may or may not be represented by a driller's record. Instances of more than one well using the same well identification number are common. All known wells have been attributed with geographic co-ordinates by the Division of Water.

Other than nominal descriptors such as "sandstone," or "gravel," the unconsolidated reservoirs are undifferentiated, either in the formally submitted water well records or published literature. Similarly, there has been insufficient subsurface work done to authoritatively differentiate the several sandstone and siltstone reservoirs. For these reasons it is not possible to confidently construct piezometric maps for the various units.

In a more regional setting, the AOR is contained within the Tuscarawas River Valley drainage basin. The United States Geological Survey (USGS) discussed subsurface water flow in the vicinity of the AOR in its "Summary of Hydrologic Data for the Tuscarawas River Basin, Ohio, with an Annotated Bibliography (2010-2015)." After recounting the availability of water well records from the Ohio Dept. Natural Resources Division of Water, and recorded water levels in domestic wells contained therein, the USGS made the following observations:

1. Groundwater flow is generally from the upland bedrock areas down into the sand- and gravel-filled valleys (general flow directions can be inferred by drawing flow lines perpendicular to contours anywhere on the map (Figure III.B.3.a.03).
2. The water-level surface mimics topography and generally follows surface-water flow directions. Topographic contours were used to refine (but not define) the contouring of the water-level elevations encountered in drilled wells, so this characteristic may be an artifact of the manner in which the contours were drawn.
3. In several areas data were too sparse to develop a water level surface.

The findings of the USGS adhere to the commonly accepted observation that water levels, and by extension, water flow, follow the surface contour of the land. As applied to the vicinity Buckeye Brine facility, a large portion of the local groundwater will flow east to west through the Tuscarawas River valley itself, this mostly south of the facility. A lesser amount of water will be derived from the higher ground north of the facility, the water moving in a south to south-southeast direction before mixing with the water in the river valley sediments and proceeding westward. With specific reference to the Buckeye Brine facility, subsurface water movement across the property will be primarily in a south-southwest direction across the property (Figure II.B.3.a.04). Actual land surface profiles in the vicinity of the facility are illustrated in Figure III.B.3.a.05 and indicate the south and southwest components to be the primary contributors to determining the direction of ground water flow.

II.B.5 LOCAL STRATIGRAPHY

The Buckeye Brine (Buckeye) No. 1 Adams (API #331034271770000), which is located in the center of the AOR, serves as the type log for this discussion (Fig. II.B.5.01). Unless otherwise noted, depths and thicknesses will be referenced to that well.

PRECAMBRIAN

Based on drill cuttings in the AOR, the Precambrian is granitic in composition. Drilling experiences and wireline logs suggest that the upper portion of the Precambrian may be present as a "granite wash," either a highly weathered and/or detrital form of the native rock that is relatively easy to drill.

CAMBRIAN PERIOD

Mt. Simon/Basal Sand

The 80 ft. thick Mt. Simon is the lowermost of the Cambrian units. Until very recently the Mt. Simon was considered an omnipresent reservoir across Ohio. However, in eastern Ohio it is noticeably finer textured and contains a higher percentage of associated dolomite than it does in central and western Ohio. These factors work against its role as a reservoir, and the Mt. Simon continues to degrade further to the east. An isolated injection test of the Mt. Simon in the Ohio Geological Survey #1 CO2 (API #34157253340000), 20 miles east of the AOR in Salem Twp., Tuscarawas Co., similarly determined there was essentially no injection potential (Wickstrom, et al, 2011).

What is called the Rome dolomite (Janssens, 1972) in eastern Ohio is considered as having two identifiable parts, a lower arenaceous dolomite section and an upper pure dolomite section.

The approximately 40 ft. thick basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone. It is an arenaceaous dolomite with a fine-textured sand content that decreases upward. Some thin (<4 ft.) framework sandstones may be present. None of this lower section has been found to have enough porosity or permeability to act as a reservoir. The upper 510 ft. of the Rome is chiefly a micro-crystalline dolomite with some portions exhibiting a slightly sucrosic texture. Supplies of clastic admixtures were cut off. The upper boundary of the Rome is considered an unconformity surface. Thin (to 3 ft.) vugular porosity zones occur at random horizons within the uppermost 100 ft. of the unit. These porosity zones are interpreted as a collapsed paleo-karst system.

Throughout much of the literature the Conasauga has been identified as a shale, though it is in fact an interesting sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. On resumption of deposition in post-Rome time, thin, erratically developed sandstones were first deposited. Close comparison of the Conasauga sands in different wells suggests they are overlapping and interfingered, but individual beds may have limited lateral continuity.

The 250-ft. thick Lower Copper Ridge dolomite in the AOR was laid down during a period of constant carbonate deposition is a warm shallow sea. It is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. Locally, portions may be sucrosic, particularly near the top. Density and neutron logs typically generate favorable porosity values. Various tests have suggested a small degree of transmissivity, though not as much as would be inferred from the logs. The Lower Copper Ridge in Coshocton and adjacent Counties commonly make water during drilling, especially from the upper half of the unit, which is considered injection reservoir.

The informally named Copper Ridge "B" is a 20 ft. thick section comprised of argillaceous dolostones and gray shales. The base of the "B" zone is commonly laced with shell fragments and minor amounts of quartz sand, suggesting an unconformity surface or a shallow still-stand. The "B" zone is not known to yield oil, gas, or water in the AOR.

Like the Lower Copper Ridge, the 200 ft. thick (upper) Copper Ridge dolomite the AOR is composed of a relatively pure microcrystalline to finely crystalline dolomite, but differs in that the top of the unit is arenaceous as it transitions upward into the Rose Run sandstone. None of this upper sandy portion is developed as a framework sandstone. Despite the appearance of porosity on well logs, there is no apparent permeability to back it up.

In the AOR the Rose Run was partially eroded away in post-Knox time so that only about 70 of its full 100 ft. thick section is present. The lower sands that are present represent a still-shallowing landscape, a continuation of late Copper Ridge sedimentation, and are not as coarse of texture or as well sorted as the missing upper Rose Run sands. The reservoir properties of these lower sands, as depicted on wireline logs, are good, but in practice fail to offer a viable combination of porosity and permeability.

ORDOVICIAN PERIOD

Within the AOR, the Beekmantown was removed from the Knox Group before the top of the underlying Rose Run was eroded away. The Beekmantown will not be present in local wells unless it is contained in a Knox erosional remnant with more than enough height to contain the Rose Run.

Considerable confusion attends the nomenclature of the Wells Creek and Lower Chazy shales, which are sometimes collectively or singly referred to as the Glenwood. As discussed herein, the two are differentiated on the basis of color and lithology. The 30 ft. thick Lower Chazy is a dense, micritic, argillaceous limestone with interbedded gray shale. The underlying Wells Creek is 45 ft. thick and is composed of a hard, dense, micritic, argillaceous dolomite with interbedded shale, the whole appearing light gray or in shades of green or pale blue. Both are slowly accumulated shelf carbonates with mingled clays.

Still in a shelf environment like the Lower Chazy, but with no clastics added in, the 50 ft. thick Gull River is composed of a uniformly dense and pure, impermeable micritic limestone.

Lihtologically similar to the underlying Gull River, the Black River is about 580 ft. thick in the AOR. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale.

The uppermost carbonate unit in the Ordovician section is the 60 ft. thick Trenton limestone. The product of a slightly deeper environment than the Black River, it can be abundantly fossiliferous toward the top and may contain clay admixtures or thin dark shale.

Continuing the trend of ever deepening water, the Point Pleasant and Utica are generically considered organic black shales. They have a combined thickness of about 240 ft. Their specific lithologies range from dark brown to black argillaceous limestone to calcareous shale. Fossil shell beds may be present, and the Utica, in particular, can be quartz rich.

The entire Cincinnatian-Queenston shale sequence is an approximately 1340 ft. thick Together these units chronicle the prolonged accumulation of clay and silt in an increasingly shallow marine environment. The Cincinnatian is gray shale that grades upward into the silty red Queenston, and culminates with a regional erosion surface.

SILURIAN PERIOD

The Silurian was ushered in with deposition of nearly 200 ft. of shallow water clastics. The first was the Medina, which is irregularly developed across Ohio. In the AOR the Medina is only 13 ft. thick. Developed as a clay-laced, quartz cemented silt, it is a barely recognizable marker bed.

The 155 ft. thick Cataract Group includes the informally named Clinton sandstone. Gray shales appear above and below the Clinton, the whole demonstrating a continual influs of sediment and constantly fluctuating water depths. The Cataract is capped with a distinctive red, hematitic oolitic limestone.

In the AOR the overlying shale is 60 ft. thick, and the especially fissile shale below the Clinton is about 60-70 ft. thick. The Clinton itself is developed as a series of white, interlayered, very fine-grained to silty quartz sands with a silica cement. Porosity and permeability is low, not often exceeding 10% and 10 mD, respectively. Individual beds may be as much as 30 ft. thick, but more typically are thin, 5-20 ft. thick. In the aggregate, the net sand thickness can be 5-40 ft. All of this conspires to form a wide-ranging assortment of stratigraphic oil and gas traps. Nearly everywhere it is drilled, some manner of oil and gas is encountered in marginal to paying quantities.

The common Packer Shell moniker for the Dayton Formation (Fm.) derives from century-ago cable tool drillers who used the dolomite bed(s) as a casing seat when drilling to the Clinton sandstone. Depending on locale, the unit appears as one to three thin, transgressive lenses of micro- to coarsely crystalline, slightly fossiliferous dolomite.

The 120 ft. thick Rochester shale is the last significant influs of clastics during the Silurian. It is a mix gray shale and dense, blocky, red and green marls, the latter occurring primarily in the lower half of the unit.

The Lockport, more commonly referred to as the Newburg, is a 315 ft. thick transgressive accumulation of carbonates that may range from dolomite to limestone, the dolomite mineralogy predominating, as is the case in the AOR.

Sedimentation in eastern Ohio during the late Silurian took place in a restricted, evaporitic basin that left a 505 ft. thick sequence of dolomite and anhydrite that contains a minor amount of thin gray shale. East and north of the AOR, salt is major component of the Salina. The western limit of those salts is about 3 miles east of the Buckeye facility.

DEVONIAN PERIOD

The 180 ft. thick Bass Island and Helderberg units are the basal members of the Devonian sequence. Both have a limestone-dominant lithology, but both contain thin (to 15 ft.) dolomite sections. Both units are bounded above and below by unconformities.

As discussed herein, the 150 ft. thick Onondaga, informally referred to as the Big Lime, is a 135 ft. thick limestone plus the underlying 15 ft. thick Oriskany sandstone. The Oriskany thins from east to west and sits unconformably on the underlying Helderberg. Though the Oriskany produces gas 5 miles north of the AOR, within the AOR it has low porosity and permeability, and lacks an apparent trap.

The approximately 1540 ft. thick Ohio shale sequence contains numerous sub-units, most of which are subtle variations of gray shale. Some non-productive black shales are among the basal units.

The Berea sandstone in the AOR is a thin, shallow water, blanket type deposit that is composed of a silty, very fine-grained, mechanically cemented gray sandstone with modest porosity (to 10%) and permeability. Within the AOR it is about 20 ft. thick.

MISSISSIPPIAN PERIOD

Referred to by cable tool drillers as the "Coffee shale" for its distinctively rich brown color, the 40 ft. thick Sunbury shale is organic, slightly silty, and breaks easily under the drill. Although it does not produce oil or gas by itself, it is at least one source for the oil and gas trapped in the underlying Berea sandstone.

Locally, the approximately 150 ft. thick Cuyahoga is composed entirely of gray shale. Elsewhere in the State, particularly to the southeast, the unit may be silty in part, or even contain distinct and identifiable siltstones that are capable of delivering marginal quantities of oil and gas.

The Mississippian and Pennsylvanian section above the Cuyahoga shale is comprised of about 500-800 ft. of alternating layers of shale, siltstone, and sandstone, some shaped by cut-and-fill features. In the aggregate, these rocks are poorly documented, rarely given notation on drilling records or described from cuttings, and are almost never characterized with wireline logs.

References:

Riley, R. A., 2012, Map EG-6, Elevation Contours on the Base of the Deepest Underground Sources of Drinking Water in Ohio: Columbus, Ohio Department of Natural Resources, Division of Geological Survey, 1 Map (Scale 1:500,000).

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Slucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey

No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio

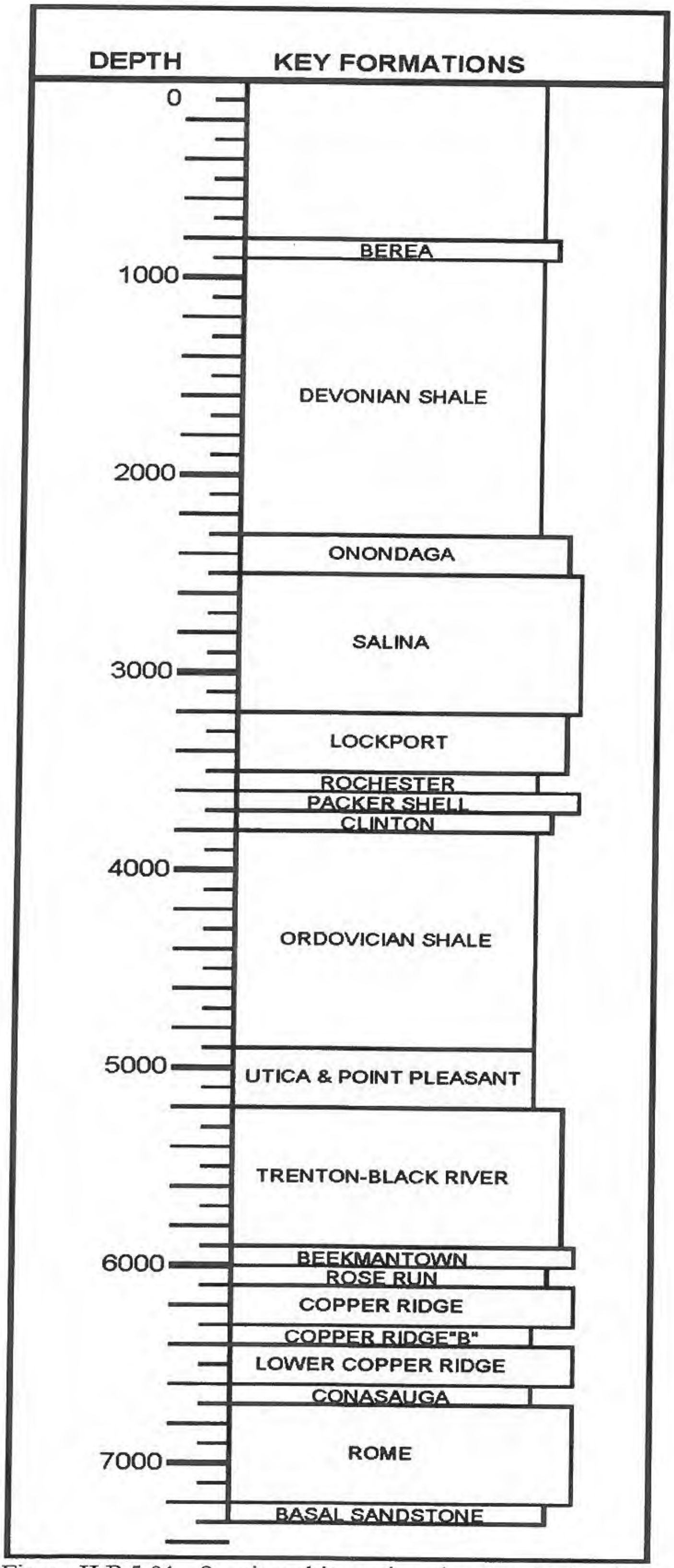


Figure II.B.5.01 - Stratigraphic section showing the key formations and sub-units in the Area of Review, and their approximate drilling depth.

II.B.6. CHARACTERISTICS OF THE INJECTION ZONE, CONFINING ZONE, AND THE LOWERMOST USDW

II.B.6.a Lowermost USDW

The deepest USDW is defined (<10,000 ppm TDS) by the U.S. EPA. In the Coshocton area and the AOR this is based on work done by Vogel (1982), which cites the Black Hand sandstone as the base of the USDW. Matchen (2006), however, maps the Black Hand as an elongated sand body trending north-south and lying about 10 miles west of the AOR and throws into question the precise stratigraphic identification of the USDW reservoir. Nonetheless, as later mapped by Riley (2012), the so-called Black Hand is cited as the deepest USDW and covers much of eastern Ohio. In the AOR, Riley's base of USDW lies at a depth of about 330 ft. from the surface (Fig. II.B.6.a-01 and Fig. II.B.6.a-02).

The depth to the USDW notwithstanding, local, domestic water is supplied chiefly by shallow domestic wells drilled into the sand and gravel that fills the Tuscarawas River valley. Typically these wells are drilled and cased to a depth of 50-75 ft. and generate excellent yields that average about 35 gallons per minute (gpm). On its map "Yields of the Unconsolidated Aquifers of Ohio," the Ohio Division of Water Resources attributes these valley-drilled wells with potentials in excess of 500 gpm. Static water levels are about 25 ft. below grade. Although a few wells have been drilled to depths of over 100 ft., their yields and static levels are comparable to those of the shallower wells.

On higher ground, away from the valley, water may be obtained from perched sandstone aquifers contained within the Allegheny Group sediments. Yields and static levels are reported as being comparable to those encountered from the sands and gravel in the river valley.

For these reasons there has been little need or desire to do detailed characterization of water sources deeper than the valley sand and gravel fill. Cable-drilled wells, generally known for the most complete descriptions of the drilled rock, are characteristically afflicted with a disinterest in shallow water-bearing zones except as they might require a casing string. Rotary-drilled wells do not use shallow cuttings except to set casing points, and no records of rock type are kept. Wireline logs acquire through fresh water bearing zones are wholly incidental to other objectives and in a best-case scenario consist of a gamma ray-neutron suite.

The illustrated log segment (Fig. II.B.6.a-02) highlights what is thought to be the unit attributed as being the lowest USDW per Riley (2012). It is contained in the upper Mississippian section. It and adjacent beds consist of shale silty sandstone. Based on the few records left by cable drillers, none of those zones are known to possess especially good porosity or permeability that would truly lend them to the purpose of supplying domestic water.

II.B.6.b Confining Zone

The Confining Zone is considered to be that portion of the wellbore above the injection string packer. In this application the confining zone is approximately 2000 ft. thick and consists of 640 ft. of Ordovician limestones and 1400 ft. of Ordovician shale. The carbonate section is frequently penetrated in the quest for oil and gas, is well documented by wireline well logs, and is well understood by drillers and geologists who attend the process of exploration drilling. The shale portion is familiar, but not extensively studied or reported.

The specific formations included in this confining zone are, from bottom to top, the Black River and Trenton limestones, and the overlying Point Pleasant, Utica, Cincinnatian, and Queenston shales.

The approximately 580 ft. thick Black River (Fig. II.B.6.b.01) is a massive, uniformly dense, non-porous, non-permeable, micro- to very finely crystalline limestone. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale. Excepting the bentonite beds and the lower shaly portion, the Black River limestone appears textbook on wireline logs, having a nearly ideal 2.70 g/cc density throughout and an approximately 4.5 PE value. Lateral continuity is excellent.

The uppermost carbonate unit in the Ordovician section is the approximately 60 ft. thick Trenton limestone. It is composed of a very fine to coarsely crystalline limestone. It is abundantly fossiliferous at the top, becoming less so toward the bottom. Portions of the unit may be argillaceous or contain very thin stringers of black shale. Because of this mixed composition, and particularly the inclusion of clays, the unit is not readily or accurately quantified with conventional porosity-driven log suites. Lateral continuity is good.

The Point Pleasant and Utica shales (Fig. II.B.6.b.02) are herein discussed together. Both are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of about 240 ft. Their specific lithologies range from argillaceous limestone to calcareous shale. Fossil shell beds may be present, particularly in the Point Pleasant. The Utica, in particular, can be arenaceous. Because of the included carbonate and quartz, the rocks are relatively hard. As is the case for the underlying Trenton, this mixed composition, plus the inclusion of low-density hydrocarbon, is beyond the scope of conventionally-run density logs. Advanced lithology logs may better characterize the unit, but none have been run in the AOR. Lateral continuity is good and, absent any hydraulic or natural fracturing, the Point Pleasant and Utica are considered impermeable, and have good lateral continuity.

The Cincinnatian is an approximately 750 ft. thick section of gray shale. Because few wells are drilled deep enough to reach the Cincinnatian and because it has no known commercial value, little attention has been paid to the unit. It remains poorly understood and poorly described. Where the Cincinnatian has been reached by the drill, it yields no shows of any kind and is thus regarded as impermeable and barren of fluids. Lateral continuity is excellent.

The Queenston is an approximately 400 ft. thick red, silty shale. The boundary between the Queenston and the underlying Cincinnatian is transitional. Having no commercial value, the Queenston is rarely given more than a cursory look, but based on drilling observations, it is considered to be an impermeable, non-reservoir rock. Lateral continuity appears excellent.

based on neutron porosity, the LCR has 81 net ft. of 7.8% average porosity. Although these are impressive numbers, testing suggests that the LCR is only capable of modest injectivity.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. In the No. 1 Adams these sands have an average density porosity of 6.8% over a 4 ft. net sand thickness. Some minor injectivity may be attributable to these sands. The upper portion of the Conasauga is an argillaceous dolomite that cannot be attributed with any viable porosity.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Neutron porosity across the approximately 37 ft. of what is thought to be sucrosic porosity averages 7.1%. Testing indicates that injectivity across these zones is limited. One or more zones of vugular porosity, thought to be the vestige of a collapsed paleo-karst topography, may be present in the upper 100 ft. of the section. This type of large-pore porosity cannot be accurately quantified with wireline logs, but testing shows that injectivity may be good to excellent.

II.B.6.d Injection Interval

The Injection Interval in the Buckeye Brine No. 1 Adams is considered that portion of the wellbore below the injection string packer that is exposed to injected fluid, that being the entirety of openhole section. In the Buckeye Brine No. 1 Adams the packer is set in the base of the Black River limestone at a depth of 5898 ft. Accordingly, the injection interval includes, from top to bottom, the Gull River, Glenwood shale (Lower Chazy and Wells Creek), Rose Run sandstone, Copper Ridge dolomite, Copper Ridge "B", Lower Copper Ridge dolomite, Conasauga dolomite and shale, Rome dolomite, and the Mt. Simon sandstone. The thickness of the injection interval from the base of the packer to top of a cement plug in the lowermost portion of the wellbore is approximately 1452 ft. The discussion that follows presents the general characteristics of each unit.

The Gull River is a regionally recognized unit that is composed of a dense, non-porous, non-permeable, micritic to microcrystalline limestone.

In a manner similar to the Gull River, the underlying Lower Chazy and Wells Creek units (commonly referred to collectively as Glenwood) are dense, non-porous, non-permeable rocks with excellent lateral continuity. Whereas the Lower Chazy is an argillaceous limestone with included shale, the Wells Creek is an argillaceous dolomite with included shale. Both can be easily traced in any direction.

The Rose Run sandstone is dominated by non-porous dolomite, but includes up to five identifiable sandstone bodies that, locally, are composed of a well-cemented, fine-grained quartz sand. The texture and degree of cementation work against an injection reservoir, and especially impinges on permeability. Density porosity, using a <2.1 PE cutoff, shows 27 net ft. of potential reservoir, but with an average density porosity of only 4.8%. There is no indication of injection into the Rose Run.

The lower portion of the 200 ft. thick Copper Ridge dolomite in eastern Ohio is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. The upper portion is arenaceous and is transitional into the overlaying Rose Run sandstone. None of the sandy sections of the Copper Ridge translate to a framework sandstone, so neutron porosity is used to assess the Copper Ridge. On that basis, 143 ft. of the section exceeds 6% porosity and averages 7.6%. Wireline porosity does not necessarily mean injectable rock. Experience with the No. 1 Adams indicates the unit to be without injectablity.

The Copper Ridge "B" is distinctive on logs and on samples for its high gamma-ray signature due to included clay and shale content. Within the AOR, the Copper Ridge is insufficiently porous to offer viable reservoir opportunities, despite optimistic porosity indicators on wireline logs.

Encountered as a massive, clean dolomite, the Lower Copper Ridge (LCR) is easily recognized in Coshocton and adjacent Counties. The upper portion of the LCR is commonly sucrosic, and well logs may indicate some manner of porosity there. During drilling, the LCR commonly gives up at least some measure of fluid, validating observations of texture in the cuttings and the values generated by the well logs. Wireline logs indicate that, based on neutron porosity, the LCR has 81 net ft. of 7.8% average porosity. Although these are impressive numbers, testing suggests that the LCR is only capable of modest injectivity.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. In the No. 1 Adams these sands have an average density porosity of 6.8% over a 4 ft. net sand thickness. Some minor injectivity may be attributable to these sands. The upper portion of the Conasauga is an argillaceous dolomite that cannot be attributed with any viable porosity.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Neutron porosity across the approximately 37 ft. of what is thought to be sucrosic porosity averages 7.1%. Testing indicates that injectivity across these zones is limited. One or more zones of vugular porosity, thought to be the vestige of a collapsed paleo-karst topography, may be present in the upper 100 ft. of the section. This type of large-pore porosity cannot be accurately quantified with wireline logs, but testing shows that injectivity may be good to excellent.

The 80 ft. thick Mt. Simon is a very fine to fine-grained quartz sand with included clays and a dolomite cement. In terms of simple analysis from well logs, density calculations show that the Mt. Simon has 60 net ft. of sand(stone) with an average porosity of 6.6% While these numbers are encouraging, testing of the No. 1 Adams has failed to indicate any injectivity. This is consistent with the emerging opinion of the Mt. Simon in eastern Ohio. An isolated injection test of the Mt. Simon in the Ohio Geological Survey #1 CO2 (API #34157253340000), 20 miles east in Salem Twp., Tuscarawas Co., similarly determined there was essentially no injection potential .

Reference cited:

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Sclucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio.

II.B.6.e Lower Confining Strata

The No. 1 Adams was drilled to a total depth of 7305 ft. and cut an estimated 8-10 ft. of the Precambrian. Prior to any testing, an approximately 20 ft. thick cement plug was set over the Precambrian, making the Mt. Simon the lowermost unit in the injection interval. The Precambrian is thus the lower confining structure.

Because of the short foothold in the Precambrian, no wireline log data was acquired over that part of the wellbore, and it remains unquantified. It is believed to be without measurable porosity of permeability.

The Mt. Simon in eastern Ohio commonly produces at least moderate porosity values on wireline logs, although those values are not known to translate to injectable porosity. Injection testing of the Buckeye Brine No. 1 Adams substantiated prior findings.

II.B.7 LOCAL STRUC TURAL CROSS-SECTIONS

Using wireline log data from wells within the AOR that were drilled into the injection interval, a north-south and a west-east cross section were constructed for the purpose of comparison to shallow (<4500 ft.) mapping and reconnaissance seismic acquired by Buckeye Brine.

Two versions of each section are presented. The structural section uses a sea level datum. The stratigraphic section uses a top-of-Trenton datum.

The structure sections show the expected southeastward dip, though the north-south line shows this more plainly. Both lines show the moderate undulation that is common at the top of the Knox Group (Rose Run), as well as Knox (Rose Run) erosional remnants that are common targets for oil and gas development. Of particular interest is the apparent structural difference between the No. 1 Adams and the No. 3 Adams.

The west-east stratigraphic section shows some eastward mild thickening of the individual units, as would be expected.

II.B.8 LOCAL STRUCTURAL GEOLOGY

A prominent surface lineament that passes close by Coshocton was originally referred to as the Coshocton Fracture Zone (Fig. II.B.8.01), and subsequent references have referred to it as the Coshocton Fault Zone. The control for the lineament was originally built from USGS digital elevation model files (Mason, 1999) and is visible on the Ohio Geological Survey's shaded elevation map. Attributed to surface fractures, it is speculated to be associated with deep-seated fracture systems. It remains poorly understood and is omitted from most maps that portray basement-influenced structure.

In reporting on the extensively researched Ohio Geological Survey No. 1 CO2 stratigraphic test (API# 3415725334) , 20 miles east of the Buckeye facility, it was reported that no regional extensive, deep-seated faults were identified within 25 miles of the test site (Wickstrom, et al., 2011)

A series of structure maps and an isopach were constructed from the available well control*. The structure maps included the Berea (Fig. II.B.8.02), Big Lime (Onondaga)(Fig. II.B.8.03), and Packer Shell (Dayton) (Fig. II.B.8.04) horizons. The isopach map presented the interval thickness from the top of the Big Lime to the top of the Packer Shell.

From the standpoint of constructing structure maps from well control, ground level elevations present a particular problem. Prior to the common usage of global positioning system (GPS) devices, a well's ground level elevation was typically derived from USGS 7.5-minute topographic maps. The accuracy of the derived ground level elevation that went into the records was dependent on the contour interval of the map, the skill and attention of the surveyor, changes to the original landform due especially to surface mining, and the driller's adherence to the surveyed location. In this Coshocton Co. area where surface mining is common, the relief is moderate to high, and the terrain highly dissected, derivative subsea values must be screened for probable accuracy. All this is to say the data quality is suspect. Judgment must be invoked to cull reasonable values from the spurious. Not all data points were utilized.

Isopach maps, not subject to the vagaries of ground level elevation, are considered to be derived from a less flawed data set.

Although the AOR employs a 2-mile radius, mapping was extended 3 miles east of the Buckeye Brine facility in order to determine the location of the Cambridge Arch.

The Berea structure clearly shows the rolled and uplifted anticline on the Berea that is the manifestation of the Cambridge Arch 3 miles east of the facility. A low area with a northwesterly orientation can be seen to pass close to the center of the AOR.

The low area seen running through the AOR on the Berea map reverses itself on the Big Lime structure and appears as a southeast-plunging nose. On the east edge of the AOR the Big Lime contour lines are more closely spaced, but show a down-to-the-east monocline in place of the shallower Berea anticline. Evidence of the Cambridge Arch is tenuous.

The structural forms seen on the Big Lime structure are mimicked on the Packer Shell structure. Whereas the relief across the breadth of the Big Lime nose was on the order of 20-25 ft., it is a more subtle 15-20 ft. on the Packer Shell surface and maintains the same orientation as seen on the Big Lime. The dip on the Big Lime has a maximum rate of approximately 80 ft./mi., but on the Packer Shell the dip is about 100 ft. per mile, at least part of which can be attributed to normal eastward thickening of all units.

The Big Lime-Packer Shell isopach is straightforward in showing a N35W trending isopach thin whose western edge passes through the Buckeye Brine facility. It should be noted that although the structural features and the isopach features appear similar, the isopach is offset to the northeast and slightly skewed relative to the structures.

At the center of the AOR, Buckeye Brine has drilled three wells. In order that all wells could, in the future, be tied to a reliable and repeatable datum, drilling and openhole wireline measurements utilized a ground level datum. The original surveyor's ground levels have been updated with GPS to account for any differences due to excavation prior to drilling. Baker-Hughes logs were run in all three wells, including:

4. No. 1 Adams - Industry-standard gamma ray-neutron, density, photo-electric, resistivity openhole logs were run from 5900 ft. to the logger's 7305 ft. total depth. A cased hole gamma ray-neutron log was run from 354-5900 ft., and a correlation gamma ray from surface to 354 ft.
5. No. 2 Adams - A gamma ray-neutron, density, photo-electric, resistivity openhole log suite was run from 5930 ft. to the logger's 7007 ft. total depth. A cased hole gamma ray-neutron log was run from 85-5930 ft., and a correlation gamma ray from surface to 85 ft. Advanced acoustic and image logs were acquired in the bottomhole interval.
6. No. 3 Adams - Gamma ray-neutron, density, photo-electric, and resistivity openhole logs were run in the intermediate hole from 838 ft. to the logger's 6035 ft. total depth, and in the bottomhole interval from 6048-7135 ft. Advanced acoustic, image, and nuclear magnetic resonance logs were acquired in the bottomhole section.

Of primary interest is a structural comparison of the No. 1 and No. 3 Adams wells, which shows the No. 1 to be low to the No. 3. It is likewise low to the No. 2 Adams. Formation tops and subsea values are shown in the following table.

	7177 #1 Adams	Subsea	7241 #3 Adams	Subsea	7178 #2 Adams	Subsea
Datum	763 GL		785 GL		786 GL	
Berea	807	*-44*	812	*-27*	821	*-35*
Big Lime	2372	-1609	2388	*-1603*	2396	*-1610*
Packer Shell	3806	*-3043*	3604	*-2819*	3620	*-2834*
Clinton	3660	*-2897*	3694	*-2909*	3674	*-2888*
Queenston	3805	*-3042*	3821	*-3036*	3822	*-3036*
Trenton	5210	*-4447*	5202	*-4417*	5212	*-4426*
Gull River	5860	*-5097*	5842	*-5057*	5842	*-5056*
Lower Chazy	5910	*-5147*	5894	*-5109*	5900	*-5114*

Wells Creek	absent		5922	*-5137*	5928	*-5142*
Beekmantown	5920	*-5157*	absent		absent	
Rose Run	5982	*-5219*	5960	*-5175*	5970	*-5184*
Copper Ridge	6098	*-5335*	6038	*-5253*	6052	*-5266*
Copper Ridge "B"	6300	*-5537*	6233	*-5448*	6254	*-5468*
Lwr Copper Ridge	6320	*-5557*	6252	*-5467*	6272	*-5486*
Conasauga	6560	*-5797*	6468	*-5683*	6496	*-5710*
Rome	6669	*-5906*	6583	*-5798*	6614	*-5828*
Mt. Simon	7215	*-6452*	7125	*-6340*	NR	-
Precambrian	7295	*-6532*	NR		NR	
Logger TD	7305	*-6542*	7135	*-6350*	7007	*-6221*

Table 2. Formation tops and subsea elevations for the Buckeye Brine No. 1, 2, and 3 Adams wells, Keene Twp., Coshocton Co. All depths during drilling and openhole logging were measured from ground level.

The No. 2 and No. 3 Adams wells, north of the No. 1 Adams, are structurally higher than the No. 1 well (Figure V.B.8.05). At the top of the Mt. Simon, the deepest common horizon in the No. 1 and No. 3 wells, the No. 1 is 112 ft. deeper, this in a surface distance of 921 ft. It is a value out of line with what is thought to be known about the relatively flat strata in the AOR. Wireline depths in all three wells repeat well. Relative ground level elevations are considered reasonable when looking at the land, and have been checked with GPS. The wellbores are considered straight (<3 degrees in the aggregate) through the intermediate holes (i.e., to the production casing points), but no deviation surveys were taken in the bottomhole sections.

The immediate impression from the subsea differences is that a fault is at play. However, a careful comparison of the tops and unit thicknesses from the Berea to the Mt. Simon shows that the most of the units in the No. 1 well are slightly thicker than those in the No. 3 well. The rates of thickening vary, but are typically less than 1.5%. Exceptions, for example, are noted:

- In the No. 1 Adams the lower half of the Conasauga thickens and the upper half thins, such that in the No. 1 well there is a net 5% thinning (Figure V.B.8.06).
- The Lower Copper Ridge in the No.1 Adams thickens slightly through most of the section relative to the No. 3 well, but the thickening is pronounced in the lowermost 40 ft. of the unit (Figure V.B.5.07). Overall the section in the No. 1 Adams is 11% thicker than in the No. 3 Adams. There does not appear to be any repeating of sections in the No. 1 well as if it were normally faulted. Likewise, there are no flags on the No. 3 Adams image log that suggest faulting is present in the wellbore that would be a means of accounting for the short section.

A close examination of the well logs for the Nos. 1, 2, and 3 Adams wells reveals no missing sections in any part of the wellbores as in the case of a normal fault, nor any repeated sections as would be the case for a reverse fault. Image logs show only small scale fracturing, such as is normally attributed as drilling-induced fracturing. There is nothing that resembles a fault zone.

Overall, the evidence is that across the breadth of the Buckeye Brine facility there appears to have been slow subsidence of varying rates over a very prolonged period of time, mimicking the manner of a growth fault as commonly seen in the Gulf of Mexico Salt Dome Province. Growth faults are the vestige of movement that occurs contemporaneously with sedimentation and may leave little or no trace of that movement other than differences in bed thickness across the plane or zone of movement (Figure V.B.8.08). However, the seismic that was run across the Nos. 3 and 1 Adams shows no breakage of the rock in the sedimentary section that overlies the Precambrian basement complex (Figure V.B.8.09), and only a very mild southward dip from the No. 3 well to the No. 1.

As is discussed in Section II.C.5, Interpretation of Seismic Data, the seismic data cannot show any faulting through the sedimentary section between the Buckeye Brine No. 1 and No. 3 Adams wells.

*Appendix V contains map Figure V.A and allied insets which show the location of all known oil and gas wells within the 2-mile radius area of review. Those wells are numerically keyed to the database Table V.A Data For All Wells Within 2 Miles of the Buckeye Brine Facility contained in Appendix V. The map similarly shows all water wells of record, and those are numerically keyed to Table V.D. which is a printed version of the spreadsheet extracted from Ohio DNR online records. Figure V.A also shows:

- Surface bodies of water
- Springs (none identified within AOR)
- Mines (surface and subsurface)
- Quarries
- Other pertinent surface features including residences and roads
- Seismic areas and faults (none known or identified within AOR)
- Boundaries of the facility

References cited:

Mason, G, 1999, Structurally Related Migration of Hydro-carbons in the Central Appalachian Basin of Eastern Ohio, Into the New Millennium: the Changing Face of Exploration in the Knox Play: Sixth Annual Fall Symposium Proceedings, Akron, Ohio, Ohio Geological Society, p. 20-32.

Wickstrom, L. H., Riley, A. R.., Spane, F. A., McDonald, Jas., Sclhucher, E. R., Zody, S. P., Wells, J. G., Howatt, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO_2 well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio, 97 p.

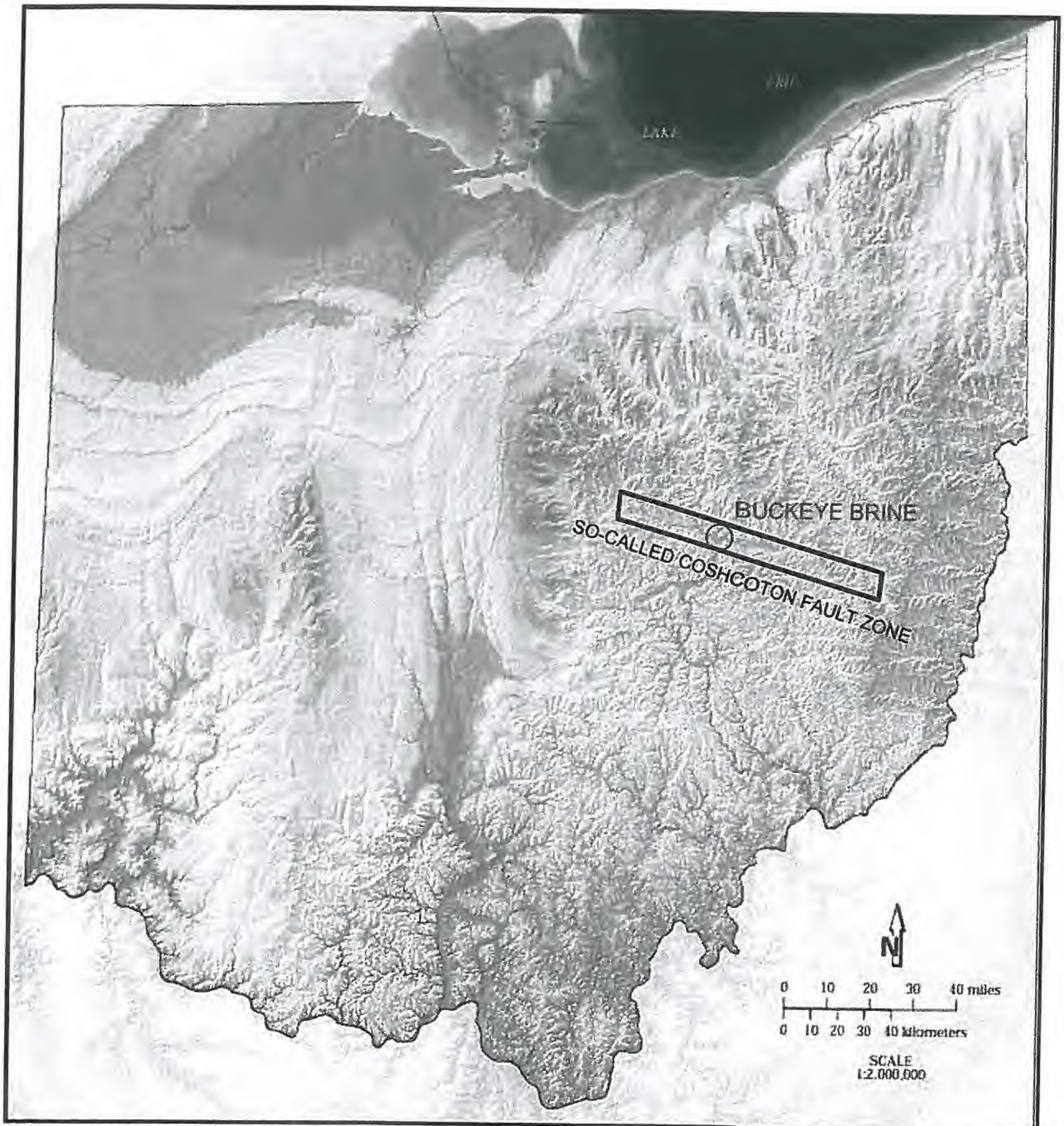


Figure II.B.8.01 Shaded relief map showing the location of the Cambridge Fracture Zone (aka Coshcoton Fault Zone) as defined by surface lineaments

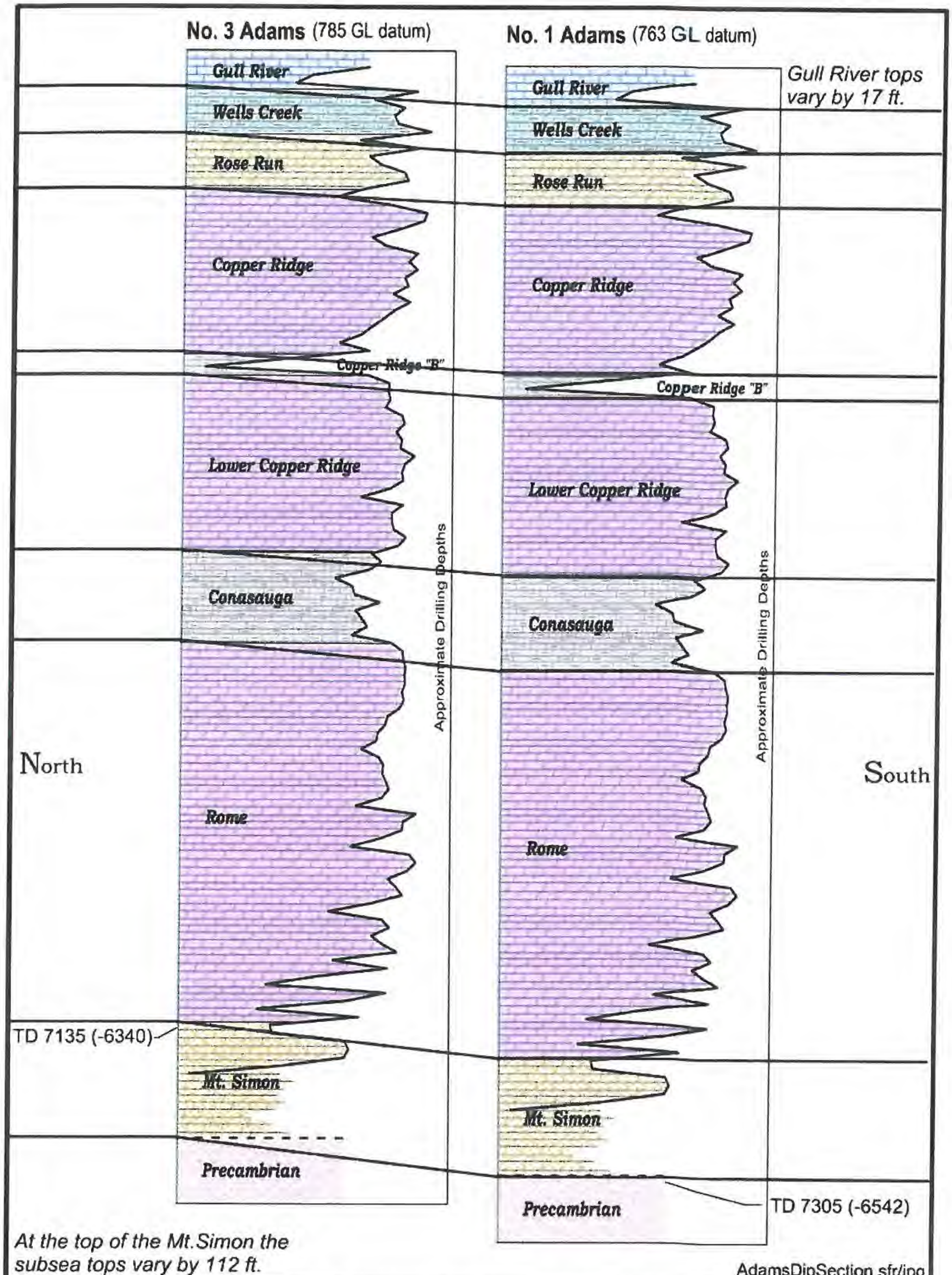


Figure II.B.8.05 - Representational cross section showing structural differences between the No. 3 Adams (left) and No. 1 Adams (right)

Attachment B

II. Seismic Discussion

II.A.5 REGIONAL SEISMIC ACTIVITY

For over 200 years of recorded history Ohio has felt the effects of earthquakes occurring outside it boundaries. In Ohio these events have registered as mild ground tremors to physical damage, as was the case for the 1812 New Madrid, Missouri series of earthquakes that damaged buildings in Cincinnati.

Within Ohio there are certain areas of the State that have historically been shown to be more earthquake prone (Fig. II.A.5.01).

A series of small and larger earthquakes that spanned more than a century in and around Anna, in western Ohio, culminated in a 1937 event that is recorded as having been a 5.4 magnitude (Richter) event. It caused extensive damage that ranged from fixable to ruinous. The most recent event was a 2.6 event recorded in 2008.

Over 100 events have been recorded in northeastern Ohio, most concentrated near the Lake Erie shoreline, with about 25 of those actually occurring in the lake, not far from shore. A 1986 magnitude 5.0 event in Lake Co. was attributed to an injection well that was eventually plugged and abandoned because of the association. However, the frequency of seismic events has continued, underscoring the inherent crustal instability in that area. Most of the earthquakes in the last 30 years have been magnitude 2.0-3.0.

About 30 small (<3.9 Richter) earthquakes are to have taken place in southern Ohio. As a group, these are widely scattered and most predate instrumented recordings.

With the onset of drilling deep Point Pleasant and Marcellus shale wells in eastern Ohio and western Pennsylvania, there have been occasional incidents of induced seismicity in connection with the very high-pressured stimulation treatments used in the wells. Such events may range up to magnitude 4.

Central and east-central Ohio have, for the most part, been without naturally-occurring seismic events.

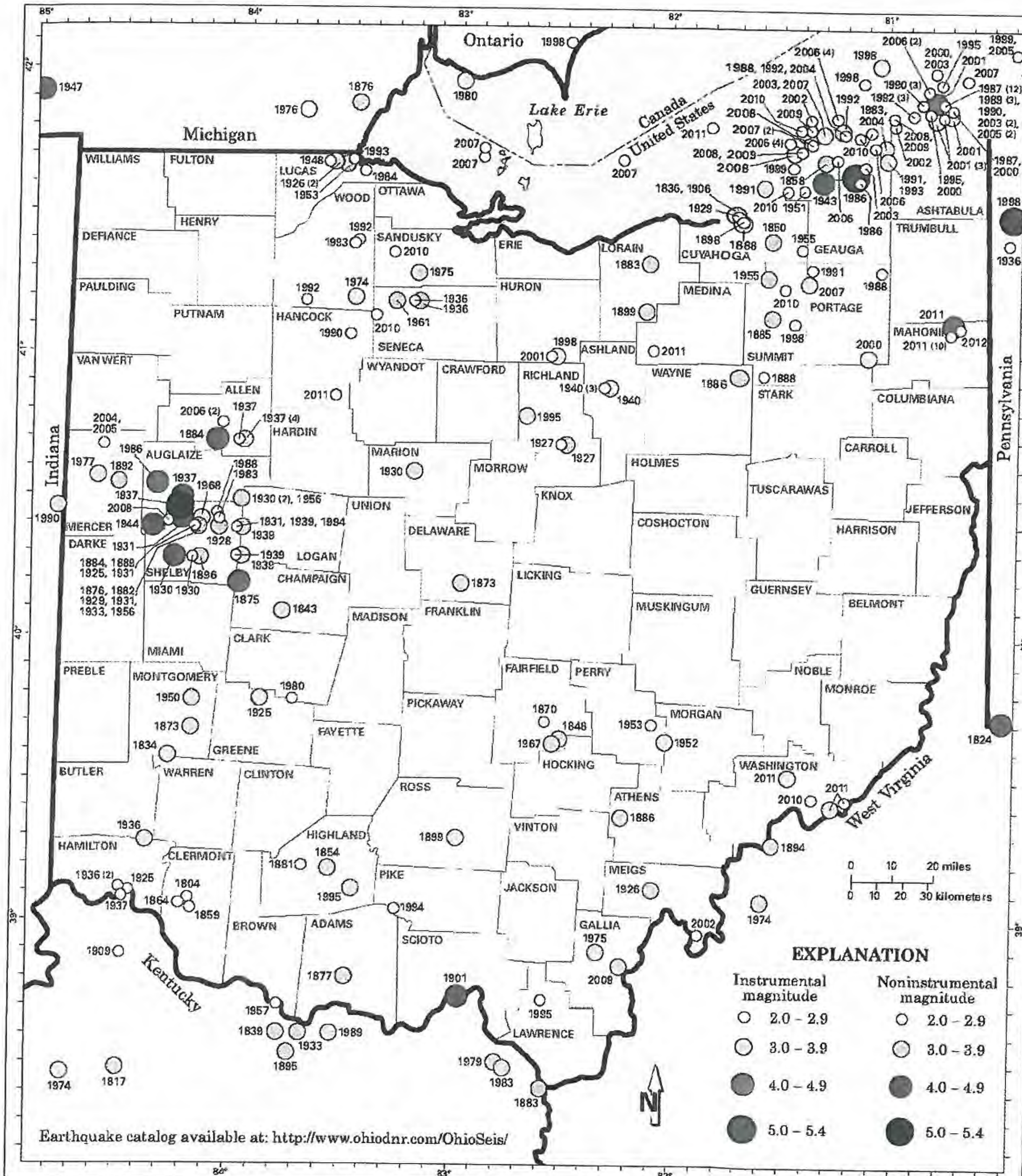


Figure II.A.5.01 - Map showing earthquake epicenters in Ohio and adjacent areas (from Ohio Div. Geological Survey Environmental Series maps BG-2 and OhioSeis Network, 2012)

GROWTH FAULT - This illustration shows two variations on vertical displacement of sedimentary rocks. On the right the displacement happened at once, fracturing all beds at the same time and effecting all beds equally. To the left the displacement has happened continually over a long period. The displacement is most evident in the lower beds; the effect on shallow beds is minimal. The displacement is some combination of fracturing, accommodation by sedimentation, and flexure.

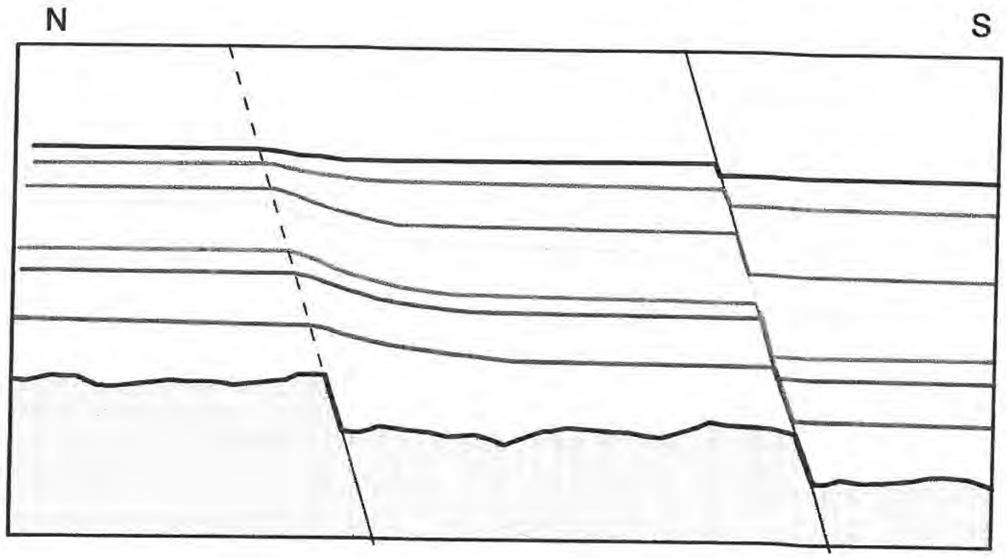


Figure II.B.8.08 – Cross-section illustrating the difference between a late-occurring normal fault (right) and a so-called growth or accommodating fault (left)

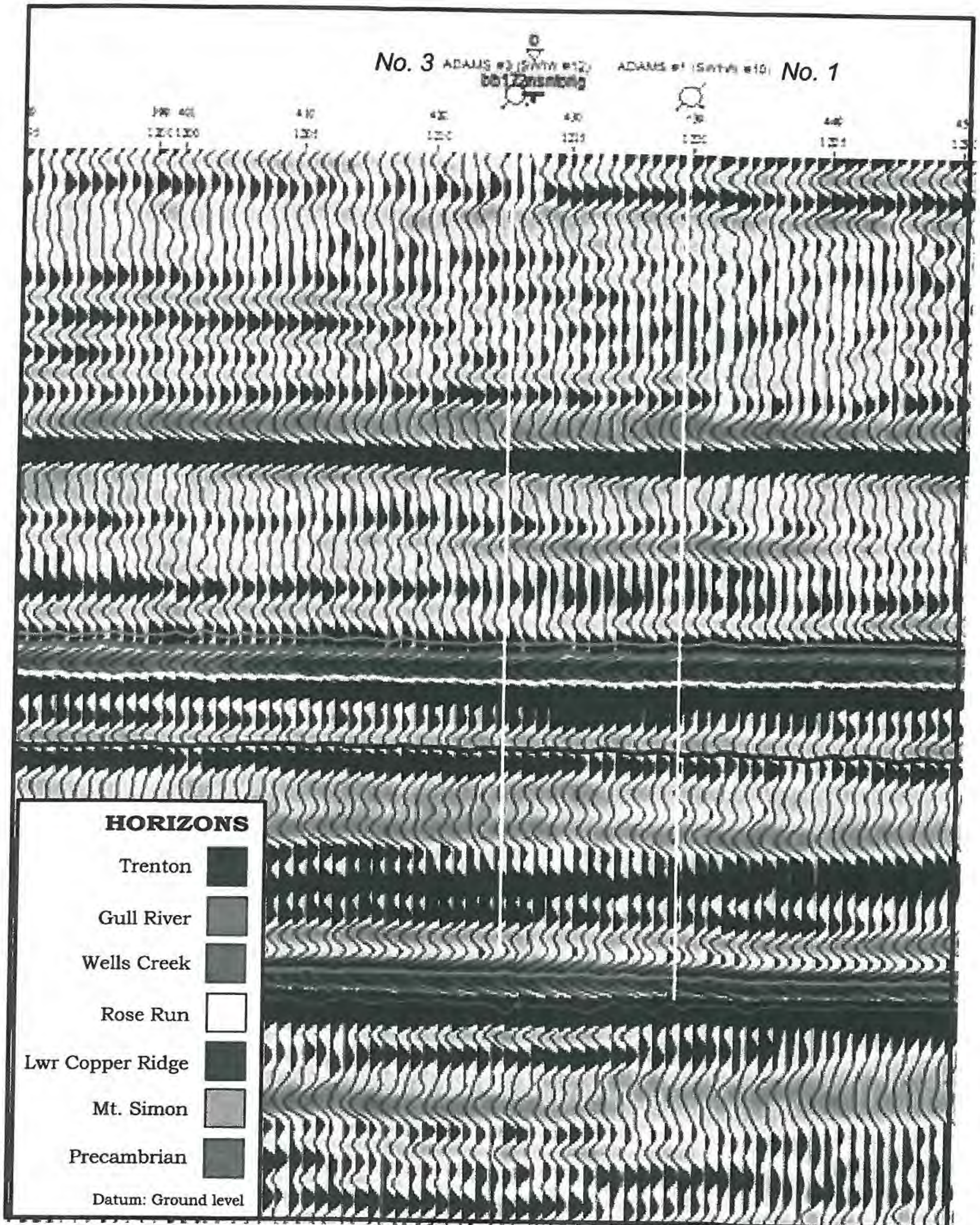


Figure II.B.8.09 – North-south seismic line BB-KTC-16-2D-1 shows an unbroken sedimentary section above the Precambrian, and portrays a slight southward structural dip from the No. 3 Adams to the No. 1 Adams.

II.C SEISMICITY, SEISMIC RECONNAISSANCE AND INTERPRETATION

II.C.1 REGIONAL AND LOCAL SEISMIC MONITORING

Regional seismic monitoring in Ohio is carried out by a number of State and Federal agencies, both scientific and regulatory.

Since 1999 the Ohio Geological Survey, in cooperation with the Ohio Emergency Management Agency, has operated the Ohio Seismic Network, also known as OhioSeis. It is Ohio's oldest wide-ranging seismic monitoring system that currently includes 27 stations deployed primarily at and operated by colleges and universities (Figure II.C.1-01). The Geological Survey coordinates the network and provides data analysis. This Ohio Geological Survey is also part of the U.S. Geological Survey Advance National Seismic System (ANSS) and is a host site for station ACSO.

CODE	LOCATION	LATITUDE	LONGITUDE	ELEV. (M)
ACEO	Jefferson	41.7387	-80.7706	292
ACSO	Alum Creek	40.2321	-82.982	282
BCSO	Carroll	39.7941	-82.5198	258
BGSO	Bowling Green	41.3794	-83.6399	208
BGFO	Huron	41.397	-82.594	185
BHSO	Botkins	40.4696	-84.1763	305
BTCO	St. Clairsville	40.0772	-80.9659	372
CLEO	Cleveland	41.5131	-81.613	205
COWO	Wooster	40.8095	-81.9368	328
CSCO	Springfield	39.8956	-83.7974	323
ECCO	Piqua	40.158	-84.2115	289
GPDO	Montville	41.5831	-81.0717	378
KSTO	New Philadelphia	40.4709	-81.4042	249
KSUO	Kent	41.151	-81.351	346
LCCO2	Kirtland	41.6393	-81.3572	245
LECO	Painesville	41.7175	-81.253	204
MACO	Marietta	39.4166	-81.4491	193
MOSO	Butler	40.6115	-82.3827	370
MUCO	Alliance	40.904	-81.11064	371
OGSO	CLOSED Columbus	40.0568	-82.9654	268
OSLO	Lima	40.7375	-84.0265	285
OSMO	Mansfield	40.797	-82.579	397
OSUO	Columbus	39.9981	-83.0109	226.1
OUAO	Athens	39.3226	-82.0997	194
SSUO	CLOSED Portsmouth	38.7306	-82.9931	162
UOCO	Cincinnati	39.1333	-84.5187	266

CODE	LOCATION	LATITUDE	LONGITUDE	ELEV. (M)
UTLO	CLOSED Toledo	41.6594	-83.618	178
WSCO	Celina	40.5467	-84.5092	270
WSDO	Dayton	39.7826	-84.0633	289
YSUO	Youngstown	41.1043	-80.648	271

The ODNR Division of Oil & Gas Resources Management (DOGRM) operates the OhioNET Seismic Network, which consists of 31 seismic monitoring stations. The stations are located in Counties throughout Ohio with oil and gas operations. They detect micro-seismic events and transmit data in real-time to DOGRM. Once alerted, the data is analyzed to determine if the seismic event is natural or whether there could be a potential relationship with human activities.

CODE	COUNTY	LATITUDE	LONGITUDE	ELEV. (M)
OHN1 (ACSOL)	Mahoning	40.979	-80.6441	377
OHN3	Mahoning	40.9621	-80.6712	325
OHN5	Mahoning	40.949	-80.6648	355
OHM6	Washington	39.3844	-81.3434	261
OHM7	Washington	39.3668	-81.3402	253
OHM8	Washington	39.3681	-81.3693	256
WES1	Washington	39.4303	-81.5112	260
WES2	Washington	39.403	-81.4772	188
OHN9	Washington	39.4091	-81.3669	247
OHU1	Muskingum	39.9545	-81.8216	303
OHH2	Harrison	40.2018	-81.2004	341
OHH3	Harrison	40.248	-81.2679	320
OHH5	Harrison	40.2492	-81.0591	303
OHR1	Meigs	38.9356	-81.7864	188
OHR2	Meigs	38.9725	-81.7891	180
OHT2	Tuscarawas	40.2913	-81.5982	266
OHT5	Tuscarawas	40.4053	-81.3129	267
OHB1	Trumbull	41.2768	-80.8954	278
OHB2	Trumbull	41.4618	-80.7216	315
OHB3	Trumbull	41.2956	-80.6894	335
OHB4	Trumbull	41.2382	-80.6277	353
CES1	Athens	39.1982	-81.7469	239
CES2	Athens	39.2509	-81.7894	221
CES3	Athens	39.2471	-81.7159	204
ORR1	Muskingum	39.9952	-81.8297	251

CODE	COUNTY	LATITUDE	LONGITUDE	ELEV. (M)
ORR2	Muskingum	39.9797	-81.8025	280
ORR3	Muskingum	39.9717	-81.8538	231
CLE1	Guernsey	40.0268	-81.5031	286
CLE2	Guernsey	40.0419	-81.5049	272
CLE4	Guernsey	40.0144	-81.4261	272
HHE1	Pickaway	39.6114	-83.049	222

II.C.2 LOCAL SEISMICITY

The Ohio Division of Geological Survey's OhioSeis catalogs earthquakes in Ohio and has actively monitored for seismic events since 1999. As of 2014 OhioSeis listed no instrumentally recorded natural or induced seismic events greater than magnitude 2.0 within 30 miles of the AOR (Figure II.C.2-01: ODNR Recent Earthquake Epicenters in Ohio Map).

Since 2013 DOGRM has deployed portable seismic stations to monitor for induced seismic events associated with oil and gas well completion operations as well as Class II disposal operations. The Division currently maintains an array of 31 stations. To date, it has not reported any seismic events greater than magnitude 2.0 within a 30-mile radius of the AOR.

Buckeye Brine (Buckeye) installed its own 3-station network around its three Class II wells beginning in September 2013. The processed data from Buckeye's network was delivered to DOGRM for a period of 18 months through February 2016. During that period neither Buckeye's seismic processor nor DOGRM identified any seismic activity attributable to Buckeye's ongoing injection operations. Buckeye has continued to collect and archive data from its network since March 2016.

At the onset of operation of Buckeye's No. 3 Adams Class II injection well (API #34031272410000), DOGRM installed a seismic station on adjacent State owned property for the purpose of providing additional monitoring over and above what was being carried out by Buckeye. For the duration of this monitoring, no induced seismicity attributable to Buckeye's injection wells was recognized by DOGRM.

II.C.3 SEISMIC PLAN

The seismic plan utilized two crossing lines with a total line length of 9.33 miles to effectively cover a 2-mile radius around the Buckeye facility.

The project area was 2 miles north of the city of Coshocton (county seat) and on the near north side of US Rt. 36.

II.C.3.a Line Layout and Coverage

The purpose of the seismic program was to help define the repose of Cambrian and Precambrian strata in the vicinity of the project area. Two intersecting lines were proposed (Figure II.C.3.a-01). The lines were acquired with a combination of dynamite and vibroseis energy sources. All stations on both lines were recorded live for increased fold. Near equal length on both sides resulted in higher stack fold near the center of the lines where the Buckeye Brine facility is located. Cultural factors influenced the line layouts.

A 4.85-mile north-south line designated as BB-KTC-16-2D-1 was run cross-country and crossed the Buckeye facility. It took advantage of utility easements and open fields. There were short skips for pipelines, roads, the airport runway, and power lines.

A 4.48-mile west-east tie line designated as BB-KTC-17-2D-2 was also run cross-country and through the Buckeye facility. There were skips on the north side of Canal Lewisville but vibe points were used to fill in where possible.

II.C.3.b Processing

The seismic processor for this project was Exploration Development, Inc. (EDI), Parker, CO (http://www.exdvpinc.com/). Their primary data processing software is the Mercury International Technology (MIT) iXl package. They also use Green Mountain Geophysical refraction statics software and various support modules written internally. Exploration Development, Inc. (EDI) has been processing seismic throughout Ohio since 1992.

Processing Flow

1. Load Data
2. Geometry Update and Trace Edit
3. Gain Recovery
4. Surface Consistent Deconvolution
5. CDP Sort
6. Zero Phase Spectral Whitening
7. Refraction Statics
8. Velocity Analysis – 2 Passes
9. NMO Corrections
10. Muting – Average NMO Stretch 1.4 to 1
11. Surface Consistent Statics – 2 Passes
12. Trace Balance
13. CDP Trim Statics
14. Dip Moveout , INMO, Vel Analysis, NMO
15. Split Frequency Trim Statics

16. Common Depth Point Stack
17. Trace Balance
18. Migration
19. Noise Subtraction
20. Time Variant Spectral Whitening
21. Further Enhancement (FX Decon / FK)
22. Trace Balance

Additionally, step 14 was replaced by Prestack Time Migration and then finalized as above.

The observer's log in the field files recorded ranges for dynamite shots and vibroseis so that the processor could indicate the various energy sources on the seismic section (Figure 11.C.3.c-01 and Figure II.C.3.c-02). Prints were plotted at 18 traces/inch and 15 inches/second (Figures II.C.3.c-03, II.C.3.c-04, II.C.3.c-05 and II.C.3.c-06).

The No. 1 Adams (API #34031271770000) synthetic was used for correlation. To match the synthetic seismogram to the seismic data, the processor cross correlated the data sets to phase match the seismic to the synthetic. This is the same process used to match the vibroseis data to the dynamite data.

Line Name	BB-KTC-16-2D-1	BB-KTC-17-2D-2
County	Coshocton	Coshocton
Township	Keene/Tuscarawas	Keene/Tuscarawas/White Eyes
Acquisition Date	12/16	2/17
SP	1101-1333	2101-2315
CDPS	202-666	202-630
Miles	4.85	4.48
Receiver Interval	110'	110'
Source Interval	110'	110'
Source	dynamite/vibroseis	dynamite/vibroseis
Sample Rate	1 ms	1 ms
Record Length	4000 ms	4000 ms
Processed Date	12/13/16	2/7/17
Bearing of Line	N to SE	W to E

II.C.4 SEISMIC INTERPRETATION METHODS

The lists below are of all the processed versions provided by EDI that were reviewed for interpretation.

BB-KTC-16-2D-1	**BB-KTC-17-2D-2**
bb161bx20	bb172bx20orig
bb161es20	bb172es20orig
bb161fk00	bb172fk00orig
bb161fk80	bb172fk80orig
bb161nsnt	bb172nsntorig
bb161ntfx	bb172ntfxorig
bb161raws	bb172rawsorig
bb161tw00	bb172tw00orig
pms161bx20	bb172bx20
pms161fk00	bb172es20
pms161fk80	bb172fk00
pms161nsnt	bb172fk80
pms161ntfx	bb172nsnt
pms161pmst	bb172ntfx
pms161tw00	bb172raws
	bb172tw00
	bb172m80
	bb172m90
	bb172m100
	bb172m110
	bb172m120
	psm172bx20
	psm172fk00
	psm172fk80
	psm172nsnt
	psm72ntfx
	psm172pmst
	psm72tw00

Interpretation was performed in GeoGraphix's SeisVision software and on paper prints of migrated, normal, and reverse polarity data. The No. 1 Adams (API# 34031271770000) synthetic was used for identification and interpretation of key reflectors on BBC-KTC-16-2D-1 and BB-KTC-17-2D-2. Analysis of individual reflectors was performed to enhance details in the seismic waveform and amplitude. Waveforms exhibit different character with different frequencies and with different geology and can confirm formation thickness and geologic sequence. Isochron mapping was compared to known geology.

Detailed wavelet character was interpreted by understanding the relationship of the local geology to the seismic information, regional geology and the frequency content of the seismic data. Time picks from reflection interpretations were then used to construct time-structure maps to show local geological relationships between the wells and for clues to paleotopography.

II.C.5 INTERPRETATION OF DATA

BB-KTC-16-2D-1 and BB-KTC-17-2D-2 were examined for evidence of deformation or faulting in the sedimentary section that could indicate a compromise of the seal in the confining layers. The Cambridge Arch was not observed on the seismic as it is too far east of the line locations and Area of Review (AOR).

Key formation horizons were picked on both lines. These included the Big Lime, Packer Shell, Trenton, Gull River, Beekmantown, Rose Run, Lower Copper Ridge, Mt. Simon, and Precambrian. Various of these horizons were later used to construct stratigraphic sections (arbitrary datums), and structure and isochron maps.

Structure maps were constructed from well control for the top of the Berea sandstone, Big Lime, and Packer Shell for later comparison to the seismic. Although some patterns were noted, it should be said that the control for the mapping was considered fair owing to the suspect nature of the ground level elevations and their effect on calculated subsea elevations. Interpretation of the seismic-generated horizons away from the actual lines themselves can be misleading. In all, the comparisons were considered too tenuous to draw meaningful conclusions. All figures identified in this section of the report are provided in Appendix II.

Figures - BB-KTC-16-2D-1

II.C.5-01 migration 80 Hz, normal polarity, grayscale

II.C.5-02 migration 80 Hz, normal polarity, wiggle trace, color amplitude

II.C.5-03 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Trenton

II.C.5-04 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Gull River

II.C.5-05 migration 80 Hz, normal polarity, wiggle trace, color amplitude, faults

II.C.5-06 migration 80 Hz, normal polarity, color amplitude, faults

II.C.5-07 migration 80 Hz, normal polarity, color amplitude, faults, compressed section

On BB-KTC-16-2D-1, the most evident structure is a basement feature on the north end from SP 1119-1140 that is herein referred to as the "Airport Dome". On the initial Figure II.C.5-5 presentation and subsequent iterations, the feature appears as a pop-up structure, the result of compression that occurred in late Precambrian, with some slow accommodation of stress that impacted lower and middle Cambrian sedimentation. The faults are not seen to extend above the base of the Precambrian.

Across the central and southern portions, line BB-KTC-16-2D-1 exhibits minor undulations, without any definable basement influence. The seismic failed to reveal faulting or vertical discontinuity between the Adams wells.

Figures - Line BB-KTC-17-2D-2

II.C.5-08 migration 80 Hz, normal polarity, grayscale

II.C.5-09 migration 80 Hz, normal polarity, wiggle trace, color amplitude

II.C.5-10 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Trenton

II.C.5-11 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Gull River

The data quality for line BB-KTC-17-2D-2 was considered fair to good in comparison to line BB-KTC-16-2D-1. It was acquired primarily through the Tuscarawas River valley where, as previously noted in Section II.C.3d, the weathered zone consisted for the most part of up to 175 ft. of unconsolidated sand and gravel valley fill. A back-filled portion of the Erie Canal and its feeder ponds are thought to have been especially detrimental to those portions of the line that are included in the intervals from SP 2101-2150 and SP 2230-2270.

The Precambrian surface shows some undulation that is considered to be within the range of normal. The most notable feature is on the west end of the line where there appears a down-to-the-west flexure contained in the interval SP 2165-2170 (Figure II.C.5-14), after which the PC surface gradually regains its previous time elevation by the west end of the line.

The Cambrian and Ordovician sedimentary section is either flat or, on the west end of the line, subtly mimics the underlying Precambrian topography (Figure II.C.5-12). None of the units appear faulted so as to compromise the sealing capability of the designated confining layer.

There is some fabric to the Precambrian section. This may change in appearance from presentation to presentation, enough so that it cannot be determined if the fabric is due to structure (folding and/or faulting), or changes in the rock character.

The data was used to construct time structure maps for the Trenton, Gull River, and Precambrian. Isochron maps were made for the Trenton-Precambrian and Gull River-Precambrian intervals.

Figures - Time Structure and Isochron Maps

II.C.5-12 Trenton Horizon, Time Structure Map

II.C.5-13 Gull River Horizon, Time Structure Map

II.C.5-14 Precambrian Horizon, Time Structure Map

II.C.5-15 Trenton - Precambrian Horizons, Isochron Map

II.C.5-16 Gull River - Precambrian Horizons, Isochron Map

Attachment C

Well Construction

III. INJECTION WELL CONSTRUCTION AND OPERATION

III.A. Construction and Completion Summary for Adams # 1

This UIC permit application is being prepared and submitted to authorize the conversion of a Class II waste disposal well known as the Adams #1 into a well that can receive Class I non-hazardous waste. The Adams #1 well is located within a facility constructed and operated by Buckeye Brine, LLC in Coshocton, Ohio. The Adams #1 well was spudded on 12/21/2011 and completed on 1/19/2012.

III.A.1. Well Schematic for Adams # 1

The current configuration of the Adams #1 well is depicted on Figure III.A. The schematic shows borehole sizes, tubular sizes, depths, specification and cementing information.

III.A.2. Adams #1 Total Depth

The Adams #1 well was drilled to a total depth of 7,288 feet. During routine mechanical integrity testing performed in October of 2016, wireline tools encountered resistance at a depth of 7049 feet. The obstruction is most likely fill and does not impair the ability to perform RTS, falloff, and other diagnostic testing.

III. A.3. Well Casing and Tubing Strings

The Adams #1 well was designed to exceed the current requirements for Class I injection wells and is constructed with conductor casing, surface casing, longstring casing and injection tubing, consisting of steel casing and tubing. Different factors have been incorporated into the proposed casing and tubing program including:

- Hole sizes;
- Injection zone and injection interval depths;
- Depth of lowermost underground source of drinking water (USDW);
- Injected waste and formation fluid composition, corrosiveness and compatibilities;
- Injection rates and operating pressures (annular and wellhead);
- Casing and tubing sizes, weights, grades and mechanical strength properties; and
- Types and grades of cement.

III.A.3.a. Casing and Injection Tubing- Type, Weight, Grade, Wall Thickness, End Finish, Set Depth, and Life Expectancy

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing, and injection tubing.

Conductor Pipe

Size (OD)	16 inches
Internal Diameter	15.376 inches (15.188" drift ID)
Weight	55 lb/ft
Grade	A-53 Grade B
End Finish	Welded
Setting Depth	126 feet
Life Expectancy	>30 years (life of well)

Surface Casing

Size (OD)	11.75 inch OD
Internal Diameter	11.084 (10.928" drift ID)
Weight	42 lb/ft
Grade	H40
Coupling Size	11.75 inches
Thread	ST & C
Setting Depth	894 feet (564' below lowermost USDW)
Life Expectancy	>30 years (life of the well)

Longstring Casing

Size (OD)	7 inch OD
Weight	23 lb/ft
Grade	N-80
Thread	LT & C
Setting Depth	5,898 feet
	0 – 5,898 23lb/ft, N-80) Packer top at 5,819 feet
Life Expectancy	>30 years (life of the well)

Injection Tubing

Size (OD)	4.5
Internal Diameter	4.052 inches (3.927" drift ID)
Weight	10.5 lbs/ft
Grade	J-55
Setting Depth	5,819 feet (~70 feet above top of Injection Interval)

III.A.3.b. Tubulars- Collapse Resistance, Internal Yield Pressure, Joint Strength, Yield Strength

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing and injection tubing.

Conductor Pipe (16", 55 lb/ft, A53 Grade B)

Collapse	290 psi
Burst (internal yield)	850 psi
Joint Strength	258,000 lbs
Yield Strength	384,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Surface Casing (11.75", 42 lb/ft, H40 ST&C)

Collapse	1,070 psi
Burst (internal yield)	1,980 psi
Joint Strength	307,000 lbs
Yield Strength	478,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Longstring Casing

7 ", 23 lb/ft, N-80, LT&C

Collapse	3,830 psi
Burst (internal yield)	6,340 psi
Joint Strength	442,000 lbs
Yield Strength	532,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Injection Tubing

4.5", 10.5 lb/ft, J-55

Collapse	4,010 psi
Burst (internal yield)	4,790 psi
Joint Strength	132,000 lbs
Yield Strength	165,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

III.A.3.c. Casings and Injection Tubing- Maximum External and Internal Pressures and Axial Loading Conditions during Construction, Operation, and Closure

The casing and tubing strings will be subject to different stresses during the different phases of construction, operation, and closure. An analysis is presented below to determine the maximum stresses during any of these phases. For any other condition, the stresses on the component will be less. The assumptions made here maximize the calculated stress on the component and will represent the maximum during construction, operation, and closure procedures.

External Pressures - Casings

For the maximum external pressure, it is conservatively assumed that somehow the inside of the casing in question has become entirely evacuated from surface to its total depth with only atmospheric pressure on the inside, and that a maximum formation hydrostatic pressure (assuming a 10 lb/gal equivalent mud weight) is exerted against the external surface of the casing. This condition is assumed to occur during the casing installation phase, but could also occur during jet-back cleanout operations and during closure. In any event, these conditions are very unlikely to occur, but are nonetheless presented here to provide a conservative outcome.

Design Formation Pressure

For the purposes of the casing and tubing design, the formation pressure gradient is assumed to be 0.52 psi/ft or a 10 lb/gal equivalent fluid density. See a justification for this pressure immediately below.

Measured Ambient Formation Pressure from Existing Wells

Ambient pressure measurements have been obtained from all three wells during annual MIT testing. The formation pressure gradient obtained from the October 18, 2016 ambient pressure monitoring in the Adams # 1 is calculated to be 0.470 psi/ft (3,152 psig at 6,700 feet), or 9.25 lb/gal equivalent formation density. The pressure gradient obtained from the measurement of BHP in the Adams #3 on October 19, 2016 (one day after the Adams #1 measurement) is calculated to be 0.476 psi/ft (3,331 psig at 7,000 feet). For a conservative evaluation, we assumed that the ambient formation pressure gradient of 0.52 psi/ft (10 lb/gal equivalent density). The resulting equation is:

$$\begin{aligned} \mathbf{P_{ext}} &= \mathbf{10\ lb/gal * 0.052\ psi/ft\ /\ lb/gal * Casing\ Depth} \\ &= \mathbf{0.52\ psi/ft * Casing\ Depth\ (ft)} \qquad \ldots \text{(i)} \end{aligned}$$

External Max Press$_{conductor}$ = 0.52 psi/ft * 126 ft

= 65.52 psig

External Max Press$_{surface}$ = 0.52 psi/ft * 894 ft

= 465 psig

External Max Press$_{longstring}$ = 0.52 psi/ft *5819 ft

= 3,026 psig

Note: The top of the packer is set at 5,819' BGL. The external and internal forces on the injection tubing and longstring casing are not active below this depth. For tensile strength comparisons on the injection tubing and longstring casing, the full installed length is used

Internal Pressures - Casings

For the maximum internal pressure, it is conservatively assumed that somehow the outside of the casing has become entirely evacuated from surface to its total depth with only atmospheric pressure on the outside, and that a 10 lb/gal equivalent mud weight is exerted against the internal surface of the casing. The resulting equation is given by (same as previous):

P_{int} = 10 lb/gal*0.052 psi/ft / lb/gal* Depth of Casing

= 0.52 psi/ft * Depth of casing (ft) ... (ii)

Internal Max Press$_{conductor}$ = 0.52 psi/ft * 126 ft

=65.52 psig

Internal Max Press$_{surface}$ = 0.52 psi/ft * 894 ft

= 465 psig

Internal Max Press$_{longstring}$ = 0.52 psi/ft *5819 ft

= 3,026 psig

Axial Loading - Casings

For the maximum load, it is conservatively assumed that the casing is "hanging in air" with no buoyant force exerted by the circulating fluid or surrounding formation in the borehole. This unrealistic condition could only be realized if the borehole somehow became fully evacuated of fluids, and had no circumferential contact with the walls of the borehole. Nevertheless, it is used here for a worst possible case condition. The resulting equation is given by:

Max Tension Load = Weight of Casing (lb/ft)* Depth of Casing (ft) ... (iii)

$$MaxTensionLoad_{conductor} = 55\ lb/ft * 126\ ft$$
$$= 6{,}930\ lbs$$

$$MaxTensionLoad_{surface} = 42\ lb/ft * 894\ ft$$
$$= 37{,}548\ lbs$$

7 ", 23 lb/ft, N-80

$$MaxTensionLoad_{longstring} = 23\ lb/ft * 5{,}898\ ft$$
$$= 135{,}654\ lbs$$

External Pressures - Injection Tubing

For the maximum external pressure, it is conservatively assumed that maximum external pressure is equal to the maximum allowable surface injection pressure plus an additional 100 psi. At Buckeye Brine this pressure would be 1,459 psig (MASIP = 1,359 psig + 100 psig additional differential pressure). This represents the maximum possible condition during annulus pressure testing at Buckeye Brine. During injection operations, the well is operated with much less differential pressure. Additionally, it is assumed that the annulus fluid is a base solution in 10 lb/gal the maximum annulus fluid density, although it may actually be something less. Finally, it is assumed that there is no injection pressure (no injection), and that the tubing fluids are in equilibrium with the injection interval. At Buckeye Brine, the minimum static injection interval pressure in the Adams #1 is 3,152 psig at 6,700 feet, corresponding to a hydrostatic gradient of 0.470 psi/ft. Therefore, to calculate the maximum external (differential pressure at the bottom joint of injection tubing):

External $MaxPress_{inj.tubing}$ = 10 lb/gal*0.052 psi/ft / lb/gal* Depth of injection tubing (ft) + 1,459 psig – 0.470 psi/ft* injection tubing depth ...(iv)

With the known proposed values:

External $MaxPress_{inj.tubing}$ =0.52 psi/ft*5,819 feet +1,459 psig – 0.470 *5,819 feet

Max External $Press_{inj.tubing}$ = 1,750 psig

Internal Pressures - Injection Tubing

For the maximum internal pressure exerted on the injection tubing, it is assumed that 10 lb/gal fluid is being injected into the well at the maximum allowable injection pressure (1,359 psig), and that the annulus is filled with fresh water. A column of water, in this case the annulus, exerts a downward and outward force of 0.433 psig/ft. With a column of fresh water inside the annulus and with no external pressure added at the surface, the pressure at the lowest point in the tubing above the packer would be 5,819 ft X 0.433 psig/ft. or 2,520 psig at 5819 ft. The resulting equation which incorporates the weight of water in the annulus is given by:

$InternalMaxPress_{inj.tubing}$= 0.52 psi/ft * tubing depth (ft) +1,359 psig - 0.433 psig/ft* depth of injection tubing ...(v)

Internal $MaxPress_{inj.tubing}$ =[(0.52 psi/ft*5,819 ft) +1,359 psig]- [0.433 psi x 5,819 ft]

Max Internal $Press_{inj.\ tubing}$ = 1,865 psig

Axial Loading - Injection Tubing

For the maximum tensile load, it is conservatively assumed that the injection tubing is latched into the packer with no buoyant force exerted by the annular fluid or fluid inside the injection tubing, and that there is no additional tensional loading pulled on the injection tubing (normally 10,000 – 15,000 lbs of slackoff weight is stacked onto the packer). Finally, it is assumed that the injection string is cooled by 50° F, relative to the ambient temperature at which it was landed. The resulting equation is given by:

Max Load = Tubing Wt. (lb/ft)*Tubing Depth (ft) + thermal contraction (lbs)

...(vi)

Calculate thermal contraction load from temperature change for 50° F cooling:

Thermal Tension (lbs) = 207* As * ΔT ...(vii)

(source: Baker Oil Tools Technical Handbook, 1995)

Where;

As = cross-sectional area of tubing = $(4.50^2 - 4.05^2) * \pi/4 = 3.022\ in^2$)

ΔT = temperature change (cooling in this case) = 50° F

207 = units conversion factor

$= 207 * 3.022\ in^2 * 50°F$

$= 31{,}278$ lbs

Finally, from equation (vii) above:

Max Tensile Load$_{\text{injection tubing}}$ = 10.5 lbs/ft * 5,819 ft + 31,278 lbs

= 92,378 lbs

III.A.3.d. Detailed Factor of Safety Calculations for Each Tubular String

Given the strength of the materials that comprise the proposed well casings and injection tubing, along with the calculated maximum expected (although virtually impossible to actually occur), conditions calculated in equations (i) through (vii) above, the safety factors can be determined for each component through the equation:

SF = 1 + (Material Strength – Max. Calculated Stress) / Max calculated Stress (viii)

The casing strings (conductor, surface and longstring) will be considered in I) through III) below and then the injection tubing will be considered.

I) Safety Factor for External Collapse Strength for Casings

Conductor Pipe (16", 55 lb/ft, A53)

$SF_{conductor} = 1 + (290\ psi - 65.5\ psi) / 65.5\ psi$

$SF_{conductor}$ =4.43

<u>Surface Casing (11.75", 42 lb/ft, H40 ST&C)</u>

$SF_{surf\ casing}$ = 1 + (1,070 psi – 465 psi) /465 psi

$SF_{surf\ casing}$ = 2.30

<u>Longstring Casing (7 " 23.0 lb/ft, N-80 LT&C)</u>

$SF_{longstring\ csaing}$ = 1 + (3,830 psi – 3,026psi) / 3,026 psi

$SF_{longstringcasing}$ = 1.27

<u>II) Safety Factor for Internal Yield Strength for Casings</u>

<u>Conductor Pipe (16", 55 lb/ft, A53)</u>

$SF_{conductor}$ = 1 + (850 psi – 65.5 psi) / 65.6 psi

$SF_{conductor}$ = 12.98

<u>Surface Casing (11.75", 42.0 lb/ft, H40 ST&C)</u>

$SF_{surf\ casing}$ = 1 + (1,980 psi – 465psi) / 465 psi

$SF_{surf\ casing}$ = 4.26

<u>Longstring Casing (7" 23 lb/ft, N80)</u>

$SF_{longstring\ csaing}$ = 1 + (6,340 psi – 3,026 psi) / 3,026psi

$SF_{longstringcasing}$ = 2.10

<u>III) Safety Factor for Tensile Strength for Casings (use lessor of joint strength or yield strength, as appropriate)</u>

Conductor Pipe (16", 55 lb/ft, A53)

$SF_{conductor} = 1 + (258{,}000\ lbs - 6{,}930\ lbs) / 6{,}930\ lbs$

$SF_{conductor} = 37.2$

Surface Casing (11.75", 42 lb/ft, H-40 ST&C, use joint strength)

$SF_{surf\ casing} = 1 + (307{,}000\ lbs - 37{,}548\ lbs) / 37{,}548\ lbs$

$SF_{surf\ casing} = 8.18$

Longstring Casing (7" 23 lb/ft, N80, use joint strength)

$SF_{longstring\ csaing} = 1 + (442{,}000\ psi - 135{,}654\ psi) / 135{,}654\ psi$

$SF_{longstring\ csaing}$ **= 3.26**

IV) Safety Factor for External Collapse Strength for Injection Tubing

$SF = 1 + (4{,}010 - 1{,}750 psi) / 1{,}750\ psi$

$SF_{inj\ tubing} = 2.29$

V) Safety Factor for Internal Yield Strength for Injection Tubing

$SF_{inj.tubing} = 1 + (4{,}790\ psi - 1{,}865\ psi) / 1{,}865\ psi$

$SF_{inj.tubing} = 2.57$

III) Safety Factor for Tensile Strength for Injection Tubing

Includes load for weight and thermal contraction, as discussed in Section III.A.3.c above, for Maximum Injection Tubing Stress:

$SF_{inj.tubing} = 1 + (132{,}000 \text{ lbs} - 92{,}378 \text{ lbs}) / 92{,}378 \text{ lbs}$

$sSF_{inj.tubing}$ = 1.43

In summary, the sizes, weights, grades, coupling systems, and materials of construction for the proposed new well casings and injection tubing are more than adequate for use in the proposed new well at the Buckeye Brine facility, even when considering maximum calculated conditions that greatly exceed what is expected, or that is even possible in most cases.

III.A.3.e. Injection Packer Specifications- Size, Type, Life Expectancy, and Setting Depth

The packer is a 3.5-inch x 7-inch ASI-X set, with the top of the unit at 5,819 feet BGL. The specification sheet for the packer is attached as Figure III.B at the end of this section.

III.A.3.f. Selection of Tubulars

The well design includes tubular selected based on strengths, grade, and depths related to:

- Depths of lowermost USDW, injection interval, and zone;
- Volumes of wastes to be injected;
- Pressures under static and injection conditions;
- Fluid properties (density, composition, corrosive properties, temperature) of injection and formation fluids; and
- Subsurface conditions (pressures, temperatures).

As discussed above in the detailed calculations regarding strengths of the various casings and tubular components (Section III.A.3.d), the well components are of sufficient strength to withstand a reasonable potential stress projection with substantial multiples of design capability.

Lowermost USDW Protection

The lowermost USDW, defined to be 330 feet below ground surface (Section II) is covered by two separate casing strings (surface casing and longstring casing), with each string extending through and below the USDW. A Cement Bond Log (CBL) run after cementing the surface casing indicates effective cement from the base of the surface casing (894 ft BGL) to 0 ft. BGL.

A similar CBL performed on the long string casing indicates effective cement from the bottom of the long string casing (5,898 ft. BGL) to 906 ft. BGL (See Log copies in Appendix III – A Adams #1 Construction Related Logs)

The selection of the tubular and design calculations and factor of safety calculations given above considered current and maximum possible formation densities, injection pressures, and formation pressures (both maximum and minimum in the case of complete evacuation of the borehole due to loss of circulation).

Reservoir and Injected Fluid Temperature and Pressure Considerations

As discussed in Section IV (Reservoir Mechanics) the static bottom-hole temperature at TD was measured at 145° F before injection began in the well. Logs run during subsequent annual mechanical integrity tests indicate that the maximum temperature observed at 6,700 ft. BGL is approximately 135° F. During mechanical integrity testing performed on October 18, 2016, the static reservoir pressure at 6,700 ft. BGL was measured to be 3,152 psia. Coupling the pressure increase at the maximum allowable permitted injection pressure (1,359 psig) with a maximum permitted injection fluid specific gravity of 1.2 would result in a maximum bottom-hole reservoir pressure of 4,511 psig:

Measured BHP at depth 6,700 + surface pressure at MASIP =maximum bottom hole pressure

3,152 + 1,359 = 4,511 psig.

While there are no industry standards that define High Pressure High Temperature (HPHT) reservoir conditions, Schlumberger suggests that HPHT conditions begin above 300° F and 10,000 psig. These conditions are not present at Buckeye Brine, as described in the pressure discussion above and in Section IV. Furthermore, the design calculations and factor of safety calculations presented in Section III. A3.c-d demonstrate that the selected tubular are more than sufficient to meet the expected maximum possible adverse conditions at Buckeye Brine.

III.A.4. Type of Completion and Completion Interval

The type of completion used for the Adams #1 is an open-hole that begins at the bottom of the longstring casing (5,898 ft. BGL) and extends to 7,288 ft. BGL. A schematic of the well construction and configuration is provided as Figure III.A.

III.A.5. Centralization Program

A float shoe and float collar were run on the longstring casing to facilitate adequate cementing and cement bonding. A bottom joint float collar was installed 10 ft. from the bottom of the casing and centralizers were installed on the first 10 joints run into the well.

III.A.6. Proposed Annulus (Packer) Fluid

The proposed packer fluid will consist of freshwater with a commercial corrosion inhibitor, and oxygen scavenger added at concentrations recommended by the supplier of the additives. The annulus fluid management system includes a 300 gallon poly tank for storage of the treated freshwater.

III.A.7. Drilling and Completion Procedure

The driller's daily log for the Adams #1 indicates that the well was spudded on December 21, 2011. The contents of the driller's daily log are provided as Table III.A.

Table III.3.A Drillers Log Adams #1

12/20/2011		*Moving In Wildcat Rig 1*
12/21/2011		*Finish Rigging Up ; Dig Pits ; Spud well 4:00 PM*
12/22/2011	7:00AM	*WOC ; Drilled to 125'; Run 124' - 16"Conductor Cement to surface ; good returns;Plug down 5:00AM*
12/23/2011	7:00AM	*Running 882' of 11 3/4" Surface Pipe; Drill to 937' Plug down; 46 Bbls. cement returns; cement standing up back side. Shut down for Christmas will restart drilling on Tuesday, January 3, 2012.*
1/3/2012		*Finish Blow Pit: Nippling Up; Should be Drilling by Noon*
1/4/2012	7:00AM	*1220' Drilling on Air; drilling 90'/Hr. Had problem nippling up. Got corrected ;Performed BOP test with ODNR inspector. Pressured to 595# Held for 15Mins. With no leak off.*
	1:30PM	*1701' Drilling 75'/Hr. ;Drilling with 9 7/8" VAREL PDC Bit*
1/5/2012	7:00AM	*2700' Dusting ; Top of Lime 2370' ; Current D/R 35'/Hr.*
1/6/2012	7:00AM	*3310' Soaping: D/R 1Hr. 15 Mins/Kelly ; Drilling slower than expected; 160' to be out of the Lime*
1/7/2012	2:00AM	*3688' trip bit; &;00AM back on bottom*
1/8/2012	7:00AM	*5039' Soaping*
1/9/2012	7:00AM	*Tripping out of hole; TD 9 7/8" Hole at 2:00 Am @ 5895"*
1/10/2012	7:00AM	*Cement trucks on location - mixing cement for 7". Ran 5898' 7".* Plug down at 11:30 a.m. on cement job.
1/11/2012	7:00AM	*W.O.C. ; Will run Bond Log Mid Afternoon;Unload Slim Hole DP Unload D/P ; Run bond log with Gray Wireline ; Start nippling Up*
1/12/2012	7:00 AM	*Tripping in slim hole pipe with 6 1/4" Varel 5 blade PDC Unloading hole on way in*
1/13/2012	7:00AM	*5898' -Drilling Float shoe ; Unload hole with air*
1/14/2012	7:00AM	*6457' – Soaping*
1/15/2012	7:00AM	*6810' on Fluid ; Switch to Fluid at 6538'; Pull 14 stands ,Remove string float; Water wt. 9.1#; Current ROP 15'/Hr.; Lost 660 Bbls.* in 18 Hrs. since switching to fluid ; EST. TD Monday AM
1/16/2010	7:00AM	*7065' on fluid ; Current ROP 16'/Hr.: Lost 220 Bbls. in 24 Hrs. Plan to TD @ 7200'*
1/17/2012	7:00AM	*Circulating hole;TD at 4:00AM 7270' Logging scheduled for 4:00PM*
1/18/2012	7:00AM	*Logger wrapping up. Preparing to run bottom hole packer on 4 1/2" pipe. Laid down and moved-out drill pipe. Completed logging.*

III.A.8. Cementing Program

The cementing program for the conductor, surface, and longstring casing was to circulate sufficient cement to see returns at the surface. Returns were observed by ODNR staff during the cementing of the conductor and surface casings (see ODNR completion records, casing ticket and permit forms in Appendix III).

During the cementing of the longstring casing, circulation was lost to the injection interval and returns were not observed at the surface. A cement bond log (copy provided in Appendix III) indicates that well-bonded cement is present behind the long string casing from 5,898 ft. BGL to 906 ft. BGL. A copy of the ODNR Casing Inspection Ticket, which contains information about the type and amount of cement that ODNR staff witnessed being used behind each size of casing installed, is provided as Attachment III.B.6.

III.A.9. Collection of cores and formation fluids

No cores or samples of native formation fluids were collected during the drilling and completion of Adams #1. Buckeye Brine believes that the fact that over 4 million barrels of produced saltwater have been injected into the Adams #1 well to date is evidence that the injection interval has sufficient permeability and porosity.

Class I wastes injected into the Adams #1 well in the future will be interacting initially with the injected produced saltwater as the native formation water has been displaced by the significant volumes (>10,000,000 bbls) injected into the three Adams wells since the beginning of operations in 2012.

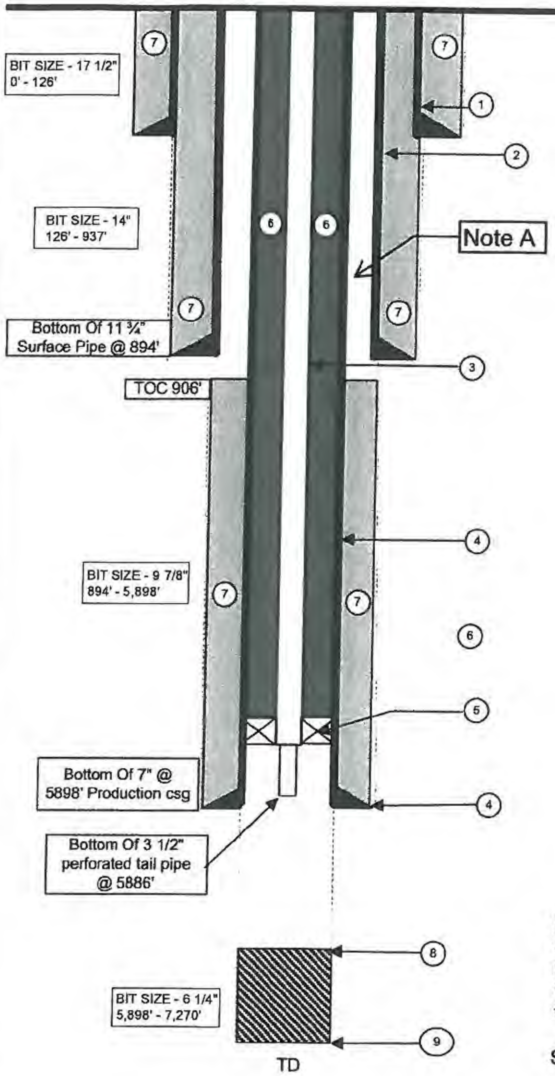
III.A.10. Logs

In early 2012, the company engaged Baker-Hughes to perform a Gamma Ray log in the open hole. Interpretation of relevant portions of the log is provided in subsection II of this Section as Appendix III.

With the long string casing in place a Radioactive Tracer Survey (RTS) and a cement bond log were performed. Copies of these two logs are also provided in the Appendix III. Interpretation of the 2016 RTS is provided in Attachment III.B.5..

Top of KB approx 775 ft ASL

763 ft ASL = Ground Level



Schematic Drawing - Not to Scale

BELOW GROUND DETAIL

1. Conductor Casing: 16", ST&C from 0-126'. Cemented to surface.
2. Surface Casing. 11 3/4", ST&C from 0-894'. Cemented to surface.
3. Injection Tubing: 4 ½" 10.5 #/ft from 0-5819' (top of PKR) 3 ½" perforated tail pipe 5826' to 5886'.
4. Protection/Longstring Casing (bottom to top): ST&C 7" 23# from 0-5898' cemented from 5898' up to 906' (Bond Log).
5. Packer: ASI-X Nickel internal Coated mandrel from 5812'-5821'.
6. Fresh Water Pkr Fluid: Annulus fluid with oxygen scavenger & corrosion inhibitor.
7. Cement: API CLASS A
8. Fill: RTS tag Oct, 2016 @ 7049'.
9. TD 7270' (fill in hole)

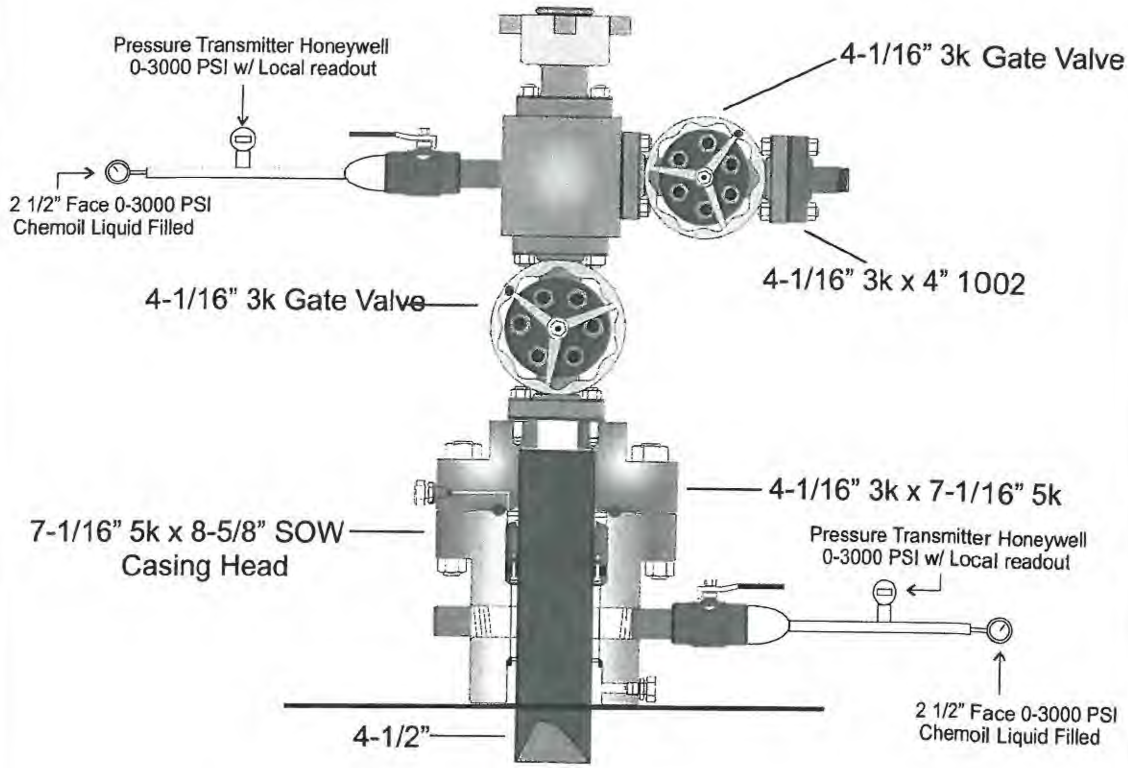
Note A: Prior to operation as a Class I UIC well and in accordance with a condition of issuance for the Class I UIC permit, Buckeye Brine will perform a cement squeeze to fill the open annular space between the 7" and 11 3/4" casings, from the depth of 906 ft bls to land surface.

Source: Titanium Environmental, LLC, 2017

Bradley S. Pekas
Digitally signed by Bradley S. Pekas
DN: cn=Bradley S. Pekas, c=US, o=Trihydro Corporation, email=bpekas@trihydro.com
Date: 2018.04.27 14:33:02 -04'00'

STATE OF OHIO
BRADLEY PEKAS
E-83267
REGISTERED
PROFESSIONAL ENGINEER

SHEET 1A 1 OF 6	ADAMS #1 - UIC WELL SCHEMATIC	Trihydro Corporation 1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	DRAWN BY: DB	BRADLEY S. PEKAS, PG, PE SR. GEOLOGIST/ENGINEER OHIO PE NO. E-83267 OH ENGINEERING COA #01867 3740 ST. JOHNS BLUFF, SUITE 14 JACKSONVILLE, FL 32224 PHONE: 800-359-0251					
			CHECKED BY: BP		B	04/27/18	FINAL	DB	BP
	BUCKEYE BRINE, LLC COSHOCTON, OH		DATE: 4/27/2018		A	04/24/18	DRAFT	DB	BP
REV: B			SCALE: NONE		REV.	DATE	DESCRIPTION	BY	CHK
			FILE: 570-UIC_WELL-DETAILS				REVISIONS		



Schematic Drawing - Not to Scale

Sources: Universal Wellhead Services, LLC 2017 and
Titanium Environmental, LLC - 2018

Bradley S. Pekas

Digitally signed by Bradley S. Pekas
DN: cn=Bradley S Pekas, c=US, o=Trihydro Corporation, email=bpekas@trihydro.com
Date: 2018.04.27 14:33:55 -04'00'

STATE OF OHIO
BRADLEY PEKAS
E-83267
REGISTERED
PROFESSIONAL ENGINEER

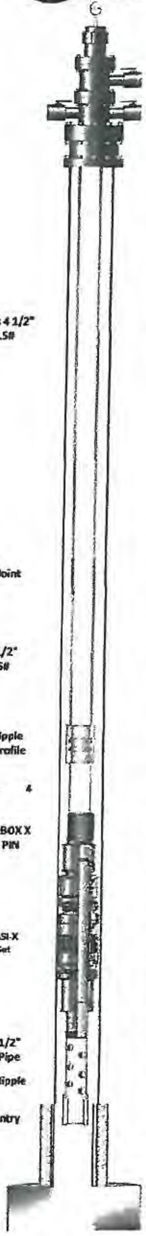
SHEET 1B 2 OF 6	ADAMS #1 - WELLHEAD DESIGN	Trihydro Corporation 1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	DRAWN BY: DB
			CHECKED BY: BP
	BUCKEYE BRINE,LLC COSHOCTON, OH		DATE: 4/27/2018
			SCALE: NONE
REV: B			FILE: 57G-UIC_WELL-DETAILS

BRADLEY S. PEKAS, PG, PE
SR. GEOLOGIST/ENGINEER
OHIO PE NO. E-83267
OH ENGINEERING COA #01867
3740 ST. JOHNS BLUFF, SUITE 14
JACKSONVILLE, FL 32224
PHONE: 800-359-0251

REV.	DATE	DESCRIPTION	BY	CHK
B	04/27/18	FINAL	DB	BP
A	04/24/18	DRAFT	DB	BP

REVISIONS

K:\PROPOSALS\BUCKEYE BRINE\DRAFTS\CADD\UIC_PERMITTING\57G-UIC_WELL-DETAILS



Buckeye Brine

Well Name	Adams	#1		Date:	10/22/2015
County:	Coshocton		State: Ohio		KB
Company Rep.	Rex Baker	Tool Operator	P. Dean		
Casing Size	7"	Tubing Size	4 1/2"		
Casing Weight	26#	Tubing Weight	10.5		
Casing Grade	J-55	Tubing Grade	J-55		

Quanity	Description	Max O.D.	Min I.D.	Length	
1	3 1/2" Re-Entry Guide	4.480	2.992	0.47	5885.74
1	3 1/2" XN-Nipple w/ 2.812 Profile	4.470	2.812	1.06	5885.27
2	3 1/2" Perforated Tubing	4.500	2.992	64.78	5884.21
1	3 1/2" x 7" ASI-X Packer	6.125	2.992	7.90	5819.43
1	3 1/2" EUE Pin x 4 1/2" STC Box Sub	5.000	3.000	0.95	5811.53
1	4 1/2" Pup Joint	5.000	4.052	8.48	5810.58
1	4 1/2" X-Nipple w/ 3.813 Profile	5.000	3.813	1.77	5802.10
5	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	210.84	5800.33
1	4 1/2" Pup Joint	5.000	4.052	8.48	5589.49
127	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	5561.81	5581.01
2	4 12" Pup joint	5.000	4.052	19.20	19.20
	Top of Packer-5811'				
	Center of Packer-5815'				
	Bottom of Packer-5819'				
	Packer Set in 16K Compression				
		Total Footage		5885.74	

Sources: Blue Dot Energy Services, LLC 2015 and Titanium Environmental, LLC - 2017

Schematic Drawing - Not to Scale

Bradley S. Pekas
Digitally signed by Bradley S. Pekas
DN: cn=Bradley S. Pekas, c=US, o=Trihydro Corporation, email=bpekas@trihydro.com
Date: 2018.04.27 14:34:40 -04'00'

STATE OF OHIO
BRADLEY PEKAS
E-83267
REGISTERED
PROFESSIONAL ENGINEER

SHEET 1C	ADAMS #1 - PACKER ASSEMBLY DESIGN	Trihydro Corporation	DRAWN BY: DB	BRADLEY S. PEKAS, PG, PE	B	04/27/18	FINAL DB BP
3 OF 6	BUCKEYE BRINE, LLC COSHOCTON, OH	1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	CHECKED BY: BP	SR. GEOLOGIST/ENGINEER	A	04/24/18	DRAFT DB BP
REV: B			DATE: 4/27/2018	OHIO PE NO. E-83267	REV.	DATE	DESCRIPTION BY CHK
			SCALE: NONE	OH ENGINEERING COA #01867			REVISIONS
			FILE: 37G-UIC_WELL-DETAILS	3740 ST. JOHNS BLUFF, SUITE 14 JACKSONVILLE, FL 32224 PHONE: 800-359-0251			

Attachment D

Operating, Monitoring, and Reporting Requirements

Adams #1

CHARACTERISTIC REQUIREMENTS	LIMITATION		MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
	Maximum	Minimum	Frequency	Frequency
*Maximum Allowable Injection Pressure Not to be exceeded	1358 psig		continuous	monthly
**Bottom-hole Pressure $_{(max)}$	4423 psig		*calculated	monthly
Annulus Pressure	50 psig higher than injection pressure throughout entire tubing length from the surface to the top of the packer		continuous	monthly
Flow Rate	290 gpm (combined monthly average)		continuous	monthly
***Flow Volume			continuous	monthly
Temperature			continuous	monthly
Specific Gravity			continuous	monthly
Sight Glass Level			daily	monthly
Corresponding Annulus Pressure			daily	monthly
Corresponding Waste Temperature			daily	monthly
Corresponding Injection Pressure			daily	monthly
Corresponding Flow Rate			daily	monthly
pH			daily	monthly
****Chemical Composition of Injectate			monthly	monthly

*Injection Pressure: (maximum allowable surface injection pressure = MASIP)

MASIP = 5898 x [0.75 - (0.433 x 1.2)] where:

5898 = depth to the top of the injection interval in true vertical depth feet

0.75 = applied fracture gradient in psi/ft

.443 = Pressure Gradient of 1 Foot of Water at 62 Degrees Fahrenheit

1.2 = fluid specific gravity

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

BHP_{max} = (0.75) (5898)

***Flow Volume: The combined monthly injection volume for the Class I wells on site must not exceed 12,710,700 million gallons, unless otherwise approved by the Director.

**** Chemical Composition: Chemical analysis shall be conducted for parameters which characterize the waste water and in accordance with the Sampling and Waste Analysis Plan after it is approved by the Director. Include monthly analysis with monthly report each month.

Attachment E

CORRECTIVE ACTION
(OAC Rules 3745-34-07 and 3745-34-30)

Protection of USDW

Should upward fluid migration occur through the wellbore of any previously unknown, improperly plugged or unplugged well in the area of review as a result of injection of fluids through the permitted well or should this migration of fluids threaten to contaminate an USDW, the injection well shall be shut-in until proper plugging can be accomplished. The Director shall determine the adequacy of the proposed corrective action of the Corrective Action Plan. 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. If data from the ground water monitoring activities or other relevant data indicate either the upward migration of fluids from the injection interval, or a threat to or contamination of an USDW, the Director may require corrective action.

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for injection Well Permit Number UIC 04-16-017-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 ________________________________

Name of Company

ATTACHMENT G

Ground Water Monitoring

Ground Water Monitoring Constituents

- For the initial sampling only, Volatile Organic Compounds as determined by analysis using US EPA Method 8260.
- pH, Specific Conductance, and Temperature to be taken in the field every time a sample is collected.
- For all samples collected analyze for Boron, Calcium, Chloride, Fluoride, Total Dissolved Solids, Sulfate, Sodium, Ammonia, Iron, Manganese, and Potassium.

Ground Water Monitoring Well Requirements

The monitoring well shall be designed, installed, and developed in a manner that allows the collection of ground water samples that are representative of ground water quality in the lowermost underground source of drinking water (USDW) and that are in accordance with the following criteria:

(a) The monitoring well shall be cased in a manner that maintains the integrity of the monitoring well boreholes.

(b) The annular space (i.e., the space between the borehole and the well casing) above the sampling depth shall be sealed to prevent the contamination of the samples and the ground water.

(c) The casing shall be screened or perforated and surrounded by sand or gravel in such a way that allows for the following:

(i) For the minimization of the passage of formation materials into the well.
(ii) For the monitoring of discrete portions of the lowermost underground source of drinking water.

SAMPLING AND ANALYSIS PROCEDURES

The sampling and analysis plan shall include copies of all blank forms necessary and a detailed description of the equipment, procedures, and techniques to be used to do the following:

(A) Are designed to ensure monitoring results that provide an accurate representation of the ground water quality in the lowermost USDW.

(B) The owner or operator shall include a description of the sample withdrawal technique including location of sampling, sampling device used, sample containers used, and sample handling and preservation for each sample obtained.

(C) Perform field analysis for temperature, pH, and specific conductance for each sample, including the following:

(1) Procedures and blank forms for recording field measurements that include the specific location, time, and site-specific conditions associated with the field data acquisition.

(2) Procedures used for the calibration of field devices and blank forms for the documentation of calibration procedures.

(D) Decontaminate all non-dedicated and non-disposable monitoring, purging, and sampling equipment prior to use

(E) Establish the chain of custody for the samples. The chain of custody form must be included with the sampling and analysis plan and shall note:

(1) Name of the facility and facility identification number as assigned by Ohio EPA, if applicable

(2) Field sample identification number for each sample.

(3) Date and time each sample was collected.

(4) The printed name and signature of each person having custody of the sample prior to its analysis with the exception of a person employed by a commercial carrier contracted to transport the ground water samples to the laboratory.

(5) The date and time that each person receives custody of the ground water sample, including the date and time the sample is relinquished to the laboratory.

(6) Chemical preservatives added to the sample.

(7) Whether ice is present or the internal temperature of each cooler when received by the laboratory.

(8) All special instructions regarding sample handling, preservation, analysis, or other information that needs to be documented to ensure that the associated sample analytical results will be representative.

(F) Obtain field quality control samples.

(G) Obtain all of the information required to be recorded on the sampling form. A copy of the blank sampling form shall also be included.

SUBMISSION OF ANALYTICAL DATA

The following information shall be submitted to and received by Ohio EPA in a form specified by the director:

(A) All results generated and information recorded in accordance with the approved sampling and analysis plan.

(B) Laboratory data sheets. The laboratory data sheets shall include at a minimum the following:

(1) Name of the facility.

(2) Field sample identification number for each ground water sample.

(3) Laboratory sample identification number for each ground water sample.

(4) Sampling date.

(5) Date the laboratory received the sample.

(6) Analytical method identification numbers for all parameters.

(7) Sample extraction date, if applicable.

(8) Sample analysis date.

(9) Analytical results for all parameters including method detection limits (MDLs), practical quantitation limits (PQLs) and any laboratory estimated values.

(10) Laboratory data qualifiers, if applicable.

(11) Sample dilution factor, if applicable.

(12) Laboratory quality control information. This information shall include at a minimum the following:

(a) Case narrative describing each problem that was encountered between sample receipt and the completion of sample analysis.

(b) Field and laboratory sample identification numbers.

(c) Holding times specified in the sampling and analysis plan for each parameter, or a statement by the laboratory that all holding time requirements were met.

(d) Whether meniscus bubbles were present in any volatile organic sample containers when received by the laboratory.

(e) Surrogate and spike recoveries with control limits.

(f) Data results from the analysis of blank samples including trip blanks, method blanks, and, if required, instrument blanks with control limits.

(g) Data from the analysis of matrix spike/matrix spike duplicates (MS/MSD) and matrix spike blanks with control limits.

(h) Relative percent difference calculations based on MS/MSD results.

(i) Laboratory control sample results if the metals spike recovery results are determined to be out of control.

(C) Data summary tables. The data summary tables shall include mine water elevation data and the analytical data collected from the sampling event applicable to the data submission and may include previously submitted data from past sampling events.

Ohio Environmental Protection Agency

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I NON-HAZARDOUS WELL

Ohio Permit No.:	UIC 04-16-018-PTO-I
Date of Issuance:	
Effective Date:	
Date of Expiration:	(5 years after issuance)
Name of Applicant:	Buckeye Brine, LLC
Facility Location:	23986 Airport Road Coshocton Ohio 43812
Mailing Address:	2630 Exposition BLVD, Suite 117 Austin, Texas 78703
County:	Coshocton
Township:	Keene
Well Number:	Adams #3
Well Location:	40°18'7.74" N/-81°51'3.25" W
Total Depth:	7135 feet below ground level (BGL) to Mt. Simon. Ground level elevation 785 feet above sea level.
Injection Interval:	Gull River to the Mt. Simon from 5912 to 7135 feet (BGL)
Containment Interval:	Trenton to Gull River from 5202 to 5912 feet (BGL)
Injection Zone:	Gull River to Mt. Simon, from 5842 to 7135 feet (BGL)
Confining Zone:	Trenton from 5202 to 5842 feet (BGL)

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 Non-Hazardous 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, F, and G.

This permit shall become effective on ________________ 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

TABLE OF CONTENTS

PART I
GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in the 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 activity in a manner that allows the movement of 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 or other private rights, or any infringement of state or local law.

This permit does not relieve the permittee of its obligation to comply with any additional regulations or requirements under the Resource Conservation and Recovery Act (RCRA) as amended or Chapter 3734 of the ORC and rules promulgated thereunder. 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 Revised Code and Part C of the federal RCRA.

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 Ohio Administrative Code (OAC) Rules 3745-34-07, 3745-34-23, and 3745-34-24, and 3745-34-26. Also, the permit is subject 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 non-compliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. <u>Transfer of Permits.</u> 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), 3745-34-23, or 3745-34-25(D) 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 obtained by the Ohio EPA pursuant to this permit may be claimed as confidential. 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 at the permitted facility.

E. DUTIES AND REQUIREMENTS

1. <u>Duty to Comply.</u> The permittee shall comply with all applicable UIC regulations and conditions of this permit, except to the extent and for the duration such non-compliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from implementation of or noncompliance with this permit. Any permit noncompliance constitutes a violation of ORC Chapter 6109 or 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such non-compliance may also be grounds for enforcement action under other applicable state and federal law.

2. <u>Penalties for Violations of Permit Conditions.</u> Any person who violates a permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapter 6111, 6109 or 3734. Any person who knowingly or recklessly violates permit conditions may be subject to criminal prosecution.

3. <u>Continuation of Expiring Permits.</u>
   a. Duty to Reapply. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 180 days before this permit expires.

b. Permit Extensions. The condition 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 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 regulation or laws.

4. <u>Need to Halt or Reduce Activity Not a Defense.</u> 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. <u>Duty to Mitigate.</u> 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.

6. <u>Proper Operation and Maintenance.</u> 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. <u>Duty to Provide Information.</u> 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, including photographing, at reasonable times any facilities, equipment (including monitoring and control equipment), activity, 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 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 OAC Rule 3745-34-12 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) 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. 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 measurements taken for the purpose of monitoring shall be representative of the monitored activity. Monitoring results shall be reported monthly in accordance with OAC Rule 3745-34-38 in a format acceptable to the Director and as set forth in paragraph 12 below.

   a. Monitoring the nature of injected fluids shall comply with the applicable analytical methods cited and described in Table I of 40 CFR 136.3 or in Appendix III of 40 CFR Part 261 or (in certain circumstances) by other methods that have been approved by the Administrator of U.S. EPA, or by the Director.

   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 wherever 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 alterations or additions to the permitted facility. Replacement of equipment that is equivalent to existing equipment is 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. Written notice shall include discussion of the changes or activity to occur, the time frame it is expected to occur, the nature of the suspected noncompliance, and planned back-up readings, if applicable. Submittal of notice of noncompliance does not stay the applicability of any permit requirement.

   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 24 hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within 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 or unless specified otherwise by the Director.

g. Monthly reports specified in OAC Rule 3745-34-38 shall be submitted by the fifteenth day of the following month. Quarterly reports shall be submitted in accordance with Part II (E) 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 immediately, in writing, if the designee or position is changed.

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

1. <u>Closure Plan.</u> A plan for closure of the well is included in Attachment A of this

permit. This plan is subject to final approval by Ohio EPA. The implementation of an 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 closure 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 activities.

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 is approved by the Director.

3. Notice of Intent to Close. The permittee shall notify the Director of its intent to close an injection well 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.

   The owner or operator of a Class I 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 either:

   a. A statement that the well was closed in accordance with Attachment A of this permit; or
   b. Where actual closure differed from Attachment A of this permit, a written statement specifying the differences between Attachment A 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 and report this information to the Director;
   b. Conduct appropriate mechanical integrity and other 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 but are not limited to:

i. Pressure tests with liquid or gas;
ii. Radioactive tracer survey;
iii. Temperature log;
iv. Casing inspection log;
v. Cement bond log; and
vi. 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 OAC Rule 3745-34-62. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection. This permit is conditioned upon the Ohio EPA approving the owner or operator's financial assurance prior to operation of the well authorized by this permit.

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

1. Post-Closure Plan. A plan for post-closure activities has been submitted and is included in Attachment A of this permit. The plan is subject to final approval by Ohio EPA. The obligation to implement an approved post-closure plan will be part of the administrative record for this permit and the permittee shall maintain and comply with this plan as if it were fully set forth herein. The obligation to maintain, implement, and comply with the post-closure plan survives the termination of this permit or the cessation of injection activities.

   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 continue post-closure maintenance and monitoring of any ground water monitoring wells required under this permit for one (1) year and 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, as identified in the administrative record for this permit. The Director may extend the period of the post-closure monitoring upon a finding that the well may endanger a USDW.

4. Survey Plat. The permittee shall submit a current plat map to the local zoning authority upon plugging 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 Resources Management, the Coshocton County Health Department, and any other State of local authority designated by the Director upon plugging 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 plugging the well in accordance with the approved closure plan required in Part I (F) of this permit, the permittee must 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 non-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, and the period over which injection occurred.

8. Financial Responsibility for Post-Closure Care. The permittee shall submit a demonstration of financial responsibility for post-closure care, as required by Chapter 3745-34 of the OAC, for approval by the Director. The owner or operator shall comply with post-closure financial assurance requirements of OAC Chapter 3745-34. The obligation to maintain financial responsibility for post-closure care survives the termination of this permit or the cessation of injection.

H. MECHANICAL INTEGRITY (OAC RULE 3745-34-34)

1. Standards. Each injection well shall maintain mechanical integrity as defined by OAC Rule 3745-34-34. The Director or his or her authorized representative shall be present during the test for demonstration of mechanical integrity, unless the Director or his or her 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 injection well shall maintain mechanical integrity of the injection well at all times.

2. Initial Mechanical Integrity Testing [OAC Rule 3745-34-55]. Prior to injection of waste fluids, the permittee shall conduct the initial 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).
   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).
   c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I)(3).
   d. An approved casing inspection log shall be run for the entire length of the long string casing in accordance with OAC Rule 3745-34-55 (A)(3)(d).

   If the permittee or the Director or the Director's authorized representative finds that the well fails to demonstrate mechanical integrity, the permittee shall not operate the well until mechanical integrity is demonstrated, and the Director or the Director's representative gives approval to commence injection.

3. Periodic Mechanical Integrity Testing [OAC Rule 3745-34-57]. Unless otherwise approved by the Director, 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) within thirty (30) days of the anniversary date of the last field 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) within thirty (30) days of the anniversary date of the last field approved demonstration;
   c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I)(3) within thirty (30) days of the three (3) year anniversary date of the last approved field 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) every five (5) years and 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 (5) years.

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).

f. The Director may require additional or alternative tests if the test results presented by the permittee are not satisfactory to the Director to demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.

4. Prior Notice and Report. 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) (3) (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. 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.

5. Gauges. The Permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half 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 ten (10) psi increments.

6. Loss of Mechanical Integrity. If the permittee or the Director or the Director's authorized representative 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 or the Director's representative gives approval to recommence injection.

7. Mechanical Integrity Testing on Request from the Director. The permittee shall demonstrate mechanical integrity at any time upon written request from the Director.

I. FINANCIAL RESPONSIBILITY (OAC Rule 3745-34-62)

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC Chapter 3745-34.

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 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 through 3745-55-45.

c. The permittee must 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 must 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 condition 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. <u>Insolvency</u>. 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 must notify the Director, in writing, within ten (10) business days.

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

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

J. CORRECTIVE ACTION

1. <u>Wells in the Area of Review</u>. The permittee shall comply with the corrective action requirements found in Attachment E of this permit and with OAC Rules 3745-34-07, 3745-34-30 and 3745-34-53.

2. <u>§3004 (u) of the Resource Conservation and Recovery Act</u>. 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. These said fees are non-refundable under any circumstance.

Part II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Surface Plumbing. The permittee shall not commence injection until it has obtained approval from Ohio EPA's Division of Surface Water and Ohio Department of Natural Resources on changes the permittee has made or will make to surface facility piping to ensure separation such that Class I Non-Hazardous waste fluids cannot be injected into the Class II well.

2. Siting [OAC Rule 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.

3. 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 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.

4. Tubing and Packer Specifications [OAC Rule 3745-34-54 (D)]. Injection shall take place only through approved tubing with an approved packer/seal assembly 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/seal assembly specifications shall be as represented in engineering drawings contained 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.

5. 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.

2. In accordance with OAC Rule 3745-34-57 (J), the permittee shall monitor the pressure buildup in the injection zone annually. The permittee shall schedule pressure buildup testing such that one (1) of the permittee's two (2) Class I injection wells is used for testing each year and each well shall be tested at least once every twenty-four (24) months unless otherwise approved by the Director.

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 approximate subsurface interval between 5912 feet and 7135 feet ground level (BGL) for Adams #3.

2. Injection Pressure Limitation [OAC Rule 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.
   b. Bottom hole pressure shall be limited so that a maximum of 4434 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 5912 feet BGL. The injection pressure shall be limited so that a maximum pressure of 1362 psig (measured at the surface) is not exceeded. The maximum surface injection pressure limit shall be adjusted downward if fluid specific gravity increases above 1.2, in accordance with the calculation set forth in Attachment D of this permit. Downward adjustments in injection pressure shall be made based on injectate specific gravity measurements made and recorded at least once every four (4) hours.

3. Injection Volume Limitation. The combined monthly flow rate for all permitted Class I injection wells at this facility shall not exceed 290 gallons per minute.

4. Additional Injection Limitation. No substances other than those identified and deemed acceptable for receipt and defined as non-hazardous shall be injected. The composite waste stream shall meet all compatibility requirements of OAC Rule 3745-34-57.

   The permittee shall submit a certified statement attesting to compliance with this requirement at the time of the annual report. The only exception to this limitation is the injection of fluids recovered from monitor wells and other fluid required for approved well testing and/or monitoring.

5. Annulus Fluids 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 (calculated) higher than injection pressure at all times throughout the injection tubing length to the top of the packer/seal assembly, for the purpose of leak detection.

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 situations:

      i. Injection pressure measured at the wellhead equals or exceeds the limit established in Part II (C) (2) of this permit; and
      ii. When injection/annulus pressure differential falls below fifty (50) psig positive differential from the injection pressure and during conditions specified above in Part II (C).

   b. Following initial testing prior to injecting waste fluids, unless otherwise approved by the Director, the permittee shall test the automatic warning and shut-off system within thirty (30) days of the anniversary date of the last field approved demonstration. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or the Director's authorized representative. The permittee shall notify the Director of its 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 or 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 an alarm or shutdown, in accordance with Part I (E) (12) 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 a 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 must 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]. The injection fluids shall be analyzed in accordance with the Ohio EPA approved waste analyses plan. 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) and Part II (C) (4) of this permit.

3. Waste Analysis Plan.
   a. The permittee has developed a written waste analysis plan which describes the procedures which it will carry out to comply with permit conditions (D) (1) and (D) (2) above and OAC Rule 3745-34-57. A copy of the approved plan shall be kept at the facility and available for inspection. The sampling and analyses shall be performed in a manner protective of human health, safety and the environment and shall produce results representative of the chemical composition of the waste analysis stream. At a minimum, the plan must specify:

      i. The parameters for which the waste stream 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.
      iv. The injectate sampling location.

   b. 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 the approved Waste Analysis Plan. The permittee shall abide by the Quality Assurance Form (Attachment F) of this permit. This form must be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

c. The permittee shall assure that the waste analysis plan remains accurate and the analyses of any fluid sampled remain representative.

4. Continuous Monitoring and Recording Devices [OAC Rule 3745-34-38 (B)(2) and [OAC Rule 3745-34-56 (F)]. The permittee shall follow the deep well monitoring requirements provided in Attachment D of this permit. 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 also be maintained and operated to monitor the injected volume. The total injected volume for the well shall be recorded at least daily.

   During periods where the permittee is unable to continuously monitor the required parameters, the permittee shall implement its Ohio EPA approved deep well monitoring contingency plan. Nothing in the contingency monitoring plan shall relieve the owner or operator of their obligation to comply with requirements under applicable state and federal law or regulations.

5. Monitoring Wells. The permittee shall submit a ground water monitoring plan for approval within thirty (30) days of permit issuance. Ground water sampling and ongoing monitoring shall commence within ninety (90) days of plan approval. The plan shall describe a monitoring program capable of assessing whether the injection activity is impacting ground water quality in the lowermost underground source of drinking of water.

   The ground water monitoring plan shall include the proposed monitoring well location, proposed well construction diagrams and installation specifications, sampling and analysis procedures and sampling reporting procedures as listed in Attachment G of this permit. All ground water samples shall be analyzed for the constituents listed is Attachment G of this permit and for any other constituent(s) required by the Director.

   A copy of the approved ground water monitoring plan shall be kept at the facility and available for inspection.

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 permittee shall follow the protocol outlined in the Ohio EPA approved corrosion monitoring plan. At a minimum, the permittee shall report loss of mass, 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. The purpose of this study was 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 Coshocton, 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 Rule 3745-34-57 (K). The monitoring system specifications, reporting frequency, content, etcetera shall be established in a monitoring plan to be submitted to the Director for approval.

c. If the Director determines that injection activities at the subject site may be inducing seismic activity capable of risk to human health and the environment, the permittee shall immediately suspend injection operations upon written notification from the Director. Injection would not be authorized to resume unless the Director indicates in writing that it is acceptable to do so based on the evaluation of the seismic data.

E. REPORTING REQUIREMENTS (OAC Rules 3745-34-38 and 3745-34-58)

1. Monthly Reports. The permittee shall submit monthly reports to the Director containing, at a minimum, all of the following information:

a. Results of the monthly injection fluid analysis specified in permit condition Part II (D) (2).
b. Daily and monthly average values for injection pressure, flow rate and volume, annular pressure, and temperature of the combined waste stream.
c. Daily and monthly maximum and minimum values for injection pressure, annulus pressure, and flow rate of the waste stream.
d. Daily minimum differential pressure.
e. The combined monthly average flow rate for all wells.
f. The results of continuous monitoring of injection pressure, annulus pressure, flow rate and injectate temperature required in permit condition Part II (D) (4). These data shall be digitized and submitted on a single graph using contrasting symbols or colors for annulus pressure, injection pressure, flow rate and injectate temperature.
g. Total fluid volume of the combined waste stream injected daily, monthly,

and the cumulative volume of fluid injected for the life of the well.

h. Date, time and volume of annulus fluid addition to or removal from the annulus system.
i. Annulus sight glass level readings noted daily at a specified time.
j. For each daily minimum and maximum injection rate reported, list the corresponding injection pressure and annulus pressure occurring during the time the well was operating at that minimum and maximum rate.
k. A listing of the duration and cause of any non-operating period for the well during the month.
l. Any procedures conducted at the injection well other than routine operational procedures.
m. Daily determinations of (injectate) pH, including monthly maximum and minimum values.
n. Determinations of injectate specific gravity a minimum of every four (4) hours.
o. Any noncompliance with conditions of this permit, including but not limited to:

    i. A description of any event that violates operating parameters for annulus pressure, injection pressure or annulus/injection pressure differential as specified in this permit; or
    ii. A description of any event which triggers an alarm or shutdown device required in Part II (C) (6) of this permit, accompanied by a description of the response taken for each event.

2. <u>Quarterly Reports [OAC Rule 3745-34-58]</u>. The permittee shall report all of the following each calendar quarter:

    a. Results of the continuous corrosion monitoring system and an interpretation of the results, as stipulated in Part II (D) of this permit, within fifteen (15) days after the end of the quarter;
    b. Results of ground water monitoring, and an interpretation of the results, as specified in an approved ground water monitoring plan, required in Part II (D) (5) of this permit, within fifteen (15) days after the end of the quarter.

3. <u>Reports on Well Tests and Workovers</u>. 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 the permit. Field log copies shall be made available the day of any geophysical well logging at the request of the Director or the Director's authorized representative. 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 pressure buildup monitoring data and analysis, 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 of the injection zone 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. 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 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 adoption of the plan, the permittee is required to submit to the Director a revised executive summary of the plan.

Attachment A

Closure and Post-Closure Plans and Cost Estimates

I. Closure Plan and Post-Closure Plan

II. Closure and Post-Closure Cost Estimate

Attachment A

I. Closure and Post-Closure Plan

Attachment III.C.1. Protocol for Plugging of the Adams #1 and Adams #3 Wells
Rev 11/10/2017

I.A.0 Mechanical Integrity Testing

At a minimum, an annular pressure test and Radioactive Tracer Survey (RTS) will be conducted on both wells to confirm the mechanical integrity of the wells prior to closure. Gauges used in these annulus pressure tests will be sensitive to changes equal to one-half of 1 percent of full scale readings. A temperature survey and/or cement bond log may also be run at the direction of the Director.

I.A.1 PLUG AND ABANDONMENT PLAN

Sections I.A.2 and I.A.3 outline the proposed plugging and abandonment procedures for the two Class I injection wells. Should it become necessary to make significant revisions to the method of closure described in the closure plan, Buckeye Brine will submit proposed changes to the Director of the Ohio EPA at least sixty (60) calendar days before closure, unless a shorter period of time is approved by the Director. Cementing will consist of three separate cement plugs, using Class H cement (or equivalent).

I.A.2 Plug and Abandon Well Adams No.1

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activities.

b. Perform APT and RAT log.

c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks.

d. Remove tree and install blow out prevention (BOP) equipment.

e. Release ASi-X mechanical packer and circulate annular fluid from well with 230 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).

f. Pull and lay down the ~5824' of 4-1/2" 10.5 lbs./ft. injection tubing and packer. Remove 4-1/2" tubing from site. Unload approximately 7,300 ft. of workstring onto pipe racks.

g. Run other logs if needed.

h. Make up a sliding valve cement retainer to set in 7" 23 lb./ft. casing on workstring. Tally workstring while running into well. Set cement retainer at bottom of casing +/- 5825'.

i. Mix and pump 310 sacks of Class A cement (yield 1.18 cf/sack) down the workstring tubing. Squeeze approximately 280 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 10 sacks of cement remain in tubing. Unstring from retainer (this action closes the sliding valve which removes the hydrostatic pressure from below the retainer) and spot remaining cement on top of retainer. Pull tubing to approximately 5620 ft. and reverse circulate until returns are clean. Trip out of hole with retainer stinger. Trip in hole with open-ended tubing. Wait for cement to harden a minimum of 8 hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5630 ft. Pressure test casing to 500 psi for 30 minutes.

k. Pull out of hole with work string, laying down joints until ~1100 ft. of workstring remains in the well and, mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 950 ft. BGL and reverse circulate until clean returns. Trip out of hole standing workstring back in derrick. Wait for cement to harden a minimum of eight hours.

l. Trip into hole and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 995 ft. Pressure test casing to 500 psi for 30 minutes.

m. Pull tubing up less than one joint and spot collar on rig floor mix and pump 150 sacks of Class A cement down workstring and circulate cement to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as workstring is removed the cement will fall downhole until all pipe is removed, approximately 38'. Pump cement remaining in pump truck into casing to raise level and washout pump truck with fresh water.

n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.

o. Rig down and move out workover rig and equipment.

p. Clean and level location. Submit required plugging reports

The closure report will certify that the well was closed as outlined in this plan, or where actual closure differed from this plan, a written statement specifying the differences between this plan and the actual closure will be provided. If both Buckeye Brine's injection wells are closed at the same time, Buckeye Brine will submit one report for both closures.

I.A.3 Plug and Abandon Well Adams No.3

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activity
b. Perform APT and RAT log.
c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks
d. Remove tree and install blow out prevention (BOP) equipment.
e. Release ASi-X mechanical packer and circulate annular fluid from well with 275 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).
q. Pull and lay down the 5917' of 4-1/2" 10.5 lbs./ft. injection tubing and the packer. Remove 4-1/2" tubing from site. Unload approximately 7,100 ft. of workstring into pipe racks.
f. Run other logs if needed.
g. Make up a sliding valve cement retainer to set in 8 5/8" 36 lb./ft. casing on workstring. Tally workstring while running into well. Set cement retainer just above packer at 5910 ft. BGL.
h. Mix and pump 325 sacks Class A cement (yield 1.18 cf/sack) down the tubing. Squeeze approximately 320 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 5 sacks of cement remain in tubing. Unstring from retainer, this closes the valve and relieves hydrostatic pressure under retainer, and spot remaining cement on top of retainer.
i. Trip out of hole with retainer stinger. Trip in hole with open-ended tubing. Wait for cement to harden a minimum of 8 hours.
j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5895 ft. Pressure test casing to 500 psi for 30 minutes.
k. Pull out of hole laying down workstring tubing until 1100 ft., of tubing remains in the well then mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 910 ft. BGL and reverse circulate until clean returns. Trip out of hole. Wait for cement to harden a minimum of 8 hours standing workstring tubing back in derrick.
l. Trip into hole with tubing and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 919 ft. Pressure test casing to 500 psi for 30 minutes.
m. Pull tubing up one joint or less and spot collar on rig floor and mix and pump 150 sacks of Class A cement and pump cement down tubing to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as the workstring is removed the cement will fall downhole until all pipe is removed, ~ 45'. Pump cement remaining in pump truck into casing to raise the level and washout pump truck.
n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.
o. Rig down and move out pulling unit and equipment.
p. Clean and level location. Submit required plugging reports.

Attachment A

II. Closure and Post-Closure Cost Estimates

Table F-1

UIC Class I Waste Injection Well
Estimate of Closing Costs (Plugging and Abandonment)
Note: These calculations are based on costs obtained in 2017

Identification		
Date	13-Aug-18	
Permit Number	Well Adams #3	
Permittee	Buckeye Brine	
Job Title	UIC Permit Application	
Well Data		
Plugging method (four plugs or cement filled)		0-Plugs or 1-Filled
Avg Well Inside Diameter (in)	7.725	
Top of Inj Interval (feet)	5,925	
Plugged Back Total Depth (feet)	7,050	
Hazardous Waste Well	0	0-No or 1-Yes
Calculated Mud Vol (bbl)	420	
Calculated Cement Vol (ft3)	467	
Costs		
Consultant		
Preclosure and postclosure work	$8,500	
Wellsite @ $1,350/day	$13,500	
Testing (MIT, pressure fall-off)	$55,100	
Workover rig, etc.	$30,000	
Mechanical bridge plug	$8,800	
Mud ($15/bbl)	$6,300	
Cement ($40/sack)	$15,567	
Welding	$1,000	
Extra Charge for haz waste well	$0	
Consultant mark-up (12%)	$14,012	
Subtotal	$152,779	
Contingency (20%)	$30,556	
Total	$183,335	
Financial Assurance Amount (2017 dollars)	$183,000	
Financial Assurance Amount Adjusted for Inflation to 2017 Dollars	$183,000	
Adjustment for inflation to 2017 Dollars	$0	
TOTAL FINANCIAL ASSURANCE	**$183,000**	

Financial Assurance for Closure and Post Closure

Table III.E Plugging and Post Closure Cost Rev 1 10/17/2017

	Adams # 1	Adams # 3	Cost at time second well plugged	Total
Injection Well Plugging Cost	$147,953	$152,779		$300,732
Post Closure				
Sampling and analysis of GW 4 Qtrs			$8,000	$8,000
Pressure falloff modeling and report			$2,500	$2,500
Plug monitor well				
Cut off casing and weld ID plate	$3,500	$3,500		$7,000
Final Report and Deed Record			$2,500	$2,500
Monitor Well Plugging Cost			$3,000	$3,000
Total Estimated Cost for both wells including post closure				$323,732
Contingency (20%)				$64,746
Total				$388,478

Attachment B

Geotechnical Information

I. Geology Description

II. Seismic Discussion

The data provided in this attachment was extracted from the UIC permit to operate applications. This attachment represents a condensed summary.

Attachment B

I. Geology Description

11.A REGIONAL GEOLOGY

II.A.1 REGIONAL STRATIGRAPHY

PRECAMBRIAN

Based on drill cuttings in the Area of Review (AOR), as well as other basement test within a 25-mile radius of the AOR, the Precambrian in the vicinity of the area of review (AOR) has been determined to be granitic in composition. Drilling experiences and wireline logs suggest that the upper portion of the Precambrian may be present as a so-called "granite wash," either a highly weathered and/or detrital form of the native rock that is relatively easy to drill. The paleotopography of the Precambrian surface is typically irregular due to a combination of differential erosion and mild tectonics. Although relief of up to 300 ft. is possible, it is more typically of a very low scale. Wireline log control is too thin to put much detail to the surface form of the Precambrian in the AOR, but seismic data in eastern Ohio routinely shows such a surface.

II.A.1.a CAMBRIAN PERIOD

Mt. Simon/Basal Sand

The Mt. Simon is the lowermost of the Cambrian units. It ranges in thickness from about 350 ft. in western Ohio and thins to about 100 ft. in eastern Ohio. In western Ohio it is a fine to coarse-grained quartz sand with a moderate to light carbonate cement, and commonly possesses moderate to excellent porosity (to 15%) and low to high permeability (0.1-10,000 mD). On the eastern edge of Ohio the Mt. Simon is a very fine-grained quartz sand with a robust carbonate cement. The net sand thickness in a 100 ft. interval is commonly less than 40 ft. Porosity as determined from wireline logs is typically less than 10%. Permeability is low, as determined from tests and observations while drilling. It has been offered by some that the sand as it exists on either side of the State is not the same formation. Accordingly, the lesser sand in the eastern part of the State is sometimes informally referred to simply as the "basal sand."

In eastern Ohio where the unit is noticeably finer textured and contains a higher percentage of associated dolomite, it may be alternately referred to as the "basal sand."

Rome Dolomite

What is called the Rome dolomite (Janssens, 1972) in eastern Ohio is a massive, white to light gray, micro- to finely crystalline section of 350-750 ft. thick dolomite. It is considered as having two identifiable parts, a lower arenaceous dolomite section and an upper pure dolomite section. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone. As such the basal Rome is an arenaceaous dolomite with a fine-textured sand content that decreases upward. Some sandstones may be included. The upper portion of the Rome may be sucrosic in parts of the section, but is generally considered to be non-porous. The upper boundary of the Rome is considered an unconformity surface.

Conasauga Shale/Dolomite

Throughout much of the literature the Conasauga has been identified as a shale, though it is in fact a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lower part of the unit. Across most of central and eastern Ohio the unit is 100-150 ft. thick, but accumulations of up to 400 ft. are present in south-central Ohio. In central Ohio, which is the effective western limit of the Conasauga; the upper portion of the unit grades laterally into the Kerbel (arenaceous dolomite).

Lower Copper Ridge Dolomite

The Lower Copper Ridge is contained within a 50-500 ft. thick interval across eastern Ohio, being thinnest in the northeast corner of the State and thickest in south-central Ohio. It is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. Locally, portions may be sucrosic and have minor porosity, and the unit commonly makes fluid while drilling.

Copper Ridge "B" Zone

The informally named Copper Ridge "B" ranges in thickness from about 200 ft. in the northeast corner of the State to about 75 ft. across the southern part of the State. Across most of its range the section comprised of argillaceous dolostones and gray shales; the basal portion may be arenaceous or contain shell fragments, suggesting possible deposition on an erosional surface. In central Ohio the unit truncates unconformably against the regional Knox unconformity. The "B" zone may be oil and gas production where the "B" zone is encountered within the subcrop zone and is contained in an erosional remnant. The "B" zone has also been productive in Knox County where hydrocarbon is structurally trapped.

Copper Ridge Dolomite

The Copper Ridge is present across eastern Ohio as a 100-350 ft. thick unit that is composed of a relatively pure microcrystalline to finely crystalline dolomite with a minor clay content. The upper portion is arenaceous and transitional into the overlaying Rose Run sandstone. The Copper Ridge subcrops against the regional Knox unconformity in central Ohio. It may constitute an excellent oil and gas reservoir where the rock occurs in paleo-erosional remnants that underwent porosity enhancement due to subaerial exposure.

Rose Run Sandstone

The Rose Run sandstone is most widely recognized across eastern Ohio as a dolomite containing a series of readily identifiable interbedded sand bodies. It ranges from about 50-125 ft. in thickness. At its western edge the Rose Run subcrops unconformably against the regional Knox erosional surface. The Knox unconformity may have positive relief that is vested in small (10-20 ac.) paleo-erosional remnants whose height is commonly on the order of 20-80 ft. Within its subcrop zone, Rose Run sands that are contained in the high-standing remnants were exposed to prolonged sub-aerial conditions that degraded the dolomitic cement in the sandstone, resulting in a substantial enhancement of porosity and permeability. Surrounded and/or overlain by younger impermeable Ordovician shale and limestone, such remnants became excellent oil and gas reservoirs. Below the grade of the Knox erosional surface or downdip from the subcrop, the porosity and permeability of the Rose Run is modest at best and, lacking any definable trapping mechanism, is barren of hydrocarbon except in the unusual circumstance of a closed structure.

II.A.1.b ORDOVICIAN PERIOD

Beekmantown Dolomite

In a manner similar to that of the underlying Rose Run sandstone, the Beekmantown is present across eastern Ohio and at it western edge is truncated against the regional Knox unconformity. This truncation occurs east of the AOR. The Beekmantown is a dense, white to light gray, micro- to very finely crystalline dolomite. Certain zone are especially prone to porosity development where the rock is contained within an erosional remnant; under those conditions it has been successfully exploited for gas production.

Wells Creek and Lower Chazy Shales

Considerable confusion attends the nomenclature of the Wells Creek and Lower Chazy shales, which are sometimes collectively or singly referred to as the Glenwood. As discussed herein, the two are differentiated on the basis of color and lithology. The approximately 30 ft. thick Lower Chazy is a dense, micritic, argillaceous limestone with interbedded gray shale. The underlying Wells Creek ranges from 30-170 ft., thickening progressively to the east. It is composed of a hard, dense, micritic, argillaceous dolomite with interbedded shale, the whole appearing light gray or in shades of green or pale blue. Both units are effective barriers to fluid migration, especially for oil and gas contained in pre-Knox erosional remnants (e.g., Rose Run and Beekmantown).

Gull River Limestone

The 45-70 ft. thick Gull River is composed of a uniformly dense and pure, impermeable micritic limestone. Across most of eastern Ohio the Gull River has a distinctive caramel color.

Black River Limestone

The Black River has a maximum thickness of about 750 ft. along the eastern edge of Ohio, thins to about 450 in central Ohio, and more or less maintains that thickness across the remainder of the State. Lithologically, it is similar to the underlying Gull River. Most of the unit is a brown or dark gray-brown, dense, impermeable micrite. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale.

Trenton Limestone

The Trenton Limestone is present across all of Ohio, ranging in thickness from about 300 ft. in the northwest part of the State to about 40 ft. in west-central Ohio. Depending on locale, it is various shades of white, light to dark gray, and brown limestone, and is typically fossiliferous. Clay and thick black shale may be included. Where fractured and subsequently dolomitized, it can be an excellent oil and gas reservoir, as was the case for the giant Findlay-Lima-Peru field in western Ohio and eastern Indiana.

Point Pleasant and Utica Shales

These two units are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of up to 240 ft. Their specific lithologies range from dark brown to black argillaceous limestone to calcareous shale. Fossil shell beds may be present, and the Utica, in particular, can be quartz rich. Because of the included carbonate and quartz, the rocks are relatively brittle and respond very well to hydraulic fracturing that is necessary for extracting hydrocarbons from these organic shales.

Cincinnatian Shale

The Cincinnatian is an approximately 500 ft. thick along the western margin of the State and about 2500 ft. thick along Ohio's southeastern border. In western Ohio the Cincinnatian is exposed at the surface as a series of thinly interlayered, fossiliferous gray shales and argillaceous limestones. In eastern Ohio few wells are drilled deep enough to reach the Cincinnatian. Because it has no known commercial value, little attention has been paid to the unit and it remains poorly understood and poorly described.

Queenston Shale

The Queenston is an approximately 400 ft. thick, red, silty shale indicative of an emergent landscape at the end of the Ordovician. It transitions downward into the Cincinnatian series of shale. The upper surface of the Queenston is erosional, and in certain locales it exhibits considerable relief, enough in instances to preclude deposition of the overlying Medina or even part of the Clinton sandstones. Having no commercial value, the Queenston is rarely given more than a cursory look, and is considered to be impermeable, non-reservoir rock.

II.A.1.c SILURIAN PERIOD

Medina Sandstone

The Medina is a thin (<20 ft.), silty to fine-grained transgressive, quartz-cemented sandstone deposited on the Queenston erosional surface. Its range is limited to the eastern third of Ohio, and it thins westward to a pinchout. Its thickness may be influenced by the paleotopography of the underlying Queenston shale. In certain restricted areas the Medina is well developed with regard to porosity and permeability; it may produce oil and gas where such sands can be encountered in an updip pinchout. Otherwise, in most areas the sand is too finely textured and lacks sufficient porosity to be considered reservoir rock.

Cataract Group/Clinton Sandstone

The Cataract Group includes the informally-termed Clinton sandstone and the gray shales above and below. In eastern Ohio the Clinton sandstone has been the backbone of the local oil and gas industry for most of a century. The unit has a 50-200 ft. range of thickness, with thickness increasing to the east. The sandstone portion of the Clinton itself is developed as a series of white and/or red, interlayered, very fine-grained to silty quartz sands with a silica cement. Porosity and permeability is low, not often exceeding 10% and 10 mD, respectively. In the western two-thirds of Ohio, the Clinton is reduced to an unremarkable gray shale and is difficult to discern from the underlying Ordovician shale.

Dayton (aka Packer Shell) Dolomite

The Dayton Formation is identifiable across Ohio. Depending on locale, the unit appears as one to three thin, transgressive lenses of micro- to coarsely crystalline, slightly fossiliferous dolomite that occur predominantly in white or shades of gray. A single lens may be from 5 to 40 ft. in thickness, and multiple lenses can be as much as 60 ft. in the aggregate. Where multiple lenses are present, the interlayered calcareous shale is gray and blocky. Additional evidence of the prevailing shallow water environment is given by the common appearance of a thin, distinctively red, hemitiic limestone oolite at its base. The common "Packer Shell" moniker for the Dayton Formation derives from century-ago cable tool drillers who used the dolomite bed(s) as a casing seat when drilling to the Clinton sandstone in eastern Ohio.

Rochester Shale

The thickness of the Rochester shale expands from about 100 ft. in the central portion of Ohio to about 300 ft. along the Ohio River on the southeastern border. The Rochester shale is a mix gray shale and dense, blocky, red and green marls, the latter occurring primarily in the lower half of the unit.

Lockport Dolomite

The Lockport, more commonly referred to as the Newburg, is an accumulation of carbonates that may range from dolomite to limestone, the dolomite mineralogy predominating. The Lockport is notable for the small (commonly 10-100 ac.) reefs contained within, these mainly in the northeastern part of the State. Where such reefs are encountered, they typically produce copious amounts of water and, on occasion, some hydrogen sulfide gas; oil and gas is less commonly encountered. Because the reefs are very porous and highly permeable, they are not infrequently utilized as small-volume disposal reservoirs. In the southern part of the State the Lockport contains the north-south trending, gas productive Williamsport sandstone that is interpreted to be a bar deposit. The Lockport is about 300 ft. across most of eastern Ohio, but thins to about 200 ft. in the northeastern corner of the State, and up to about 350 ft. in southeastern Ohio.

Salina Dolomite

The Salina ranges widely in thickness from about 300 ft. in western and central Ohio to about 1200 ft. along the Ohio River in southeast Ohio. It is composed of a sequence of dolomite and anhydrite that contains a minor amount of thin gray shale. In the eastern third of the State, salt is contained within the Salina as one or more laterally expansive and identifiable beds. Those salt beds thin and diminish in number to the west.

II.A.1.d DEVONIAN PERIOD

Bass Island and Helderberg Limestones

The 190 ft. thick Bass Island and Helderberg units are the basal members of the Devonian sequence. Both have a limestone-dominant lithology, and both contain thin (to 15 ft.) dolomite sections. The dolomites may be sucrosic and/or brecciated. The dolomite portions may have minor porosity, but rarely yield any fluids, and never produce oil or gas in the AOR. Both units are bounded above and below by unconformities.

Onondaga Limestone

As discussed herein, the Onondaga, informally referred to as the Big Lime, also includes the Oriskany sandstone, the Helderberg limestone, and the Bass Island dolomite. At their western limit where they occur at the surface, the carbonates are an important industrial mineral. The included Oriskany sandstone occurs in the eastern quarter of Ohio. It is bounded above and below by unconformities and pinches out to the west. The Oriskany has commercial value as a producer where gas and oil can be trapped in a structurally advantaged updip pinchout; lateral variations in porosity and permeability may also contribute to entrapment.

Olentangy Shale

As described herein, the approximately 140 ft. thick Olentangy is composed of a series of gray and black shales, portions of which may be calcareous or include thin beds of limestone. Within the AOR and its vicinity, none of the black shales contained in the Olentangy have a high enough total organic carbon (TOC) content to warrant consideration as hydrocarbon reservoir, though they may have generated some hydrocarbon that found its way to other reservoirs above or below.

Ohio Shale

The Ohio shale as discussed herein is about 1400 ft. thick and includes, from bottom to top, the Huron, Chagrin, and Cleveland members. Except for portions of the Huron member that contains some low TOC black shale, the interval is composed of gray shale.

Berea Sandstone

The Berea sandstone is omnipresent across eastern Ohio and ranges in thickness up to 125 ft. in northeast Ohio where it is exposed at the surface and mined as building stone. It is composed of a silty, very fine-grained, mechanically cemented pale brown to gray sandstone with modest porosity (to 10%) and permeability. It produces marginal quantities of oil and gas where favorable structural and stratigraphic conditions coincide with good reservoir conditions.

II.A.1.e MISSISSIPPIAN PERIOD

Sunbury Shale

Referred to by cable tool drillers as the "Coffee shale" for its distinctively rich brown color, the 0-40 ft. thick Sunbury shale is organic, slightly silty, and breaks easily under the drill. Although it does not produce oil or gas by itself, it is at least one source for the oil and gas trapped in the underlying Berea sandstone. Its range is the eastern third of Ohio

Cuyahoga Shale

Locally the approximately 150 ft. thick Cuyahoga is composed entirely of non-porous, non-permeable gray shale. Elsewhere in the State, particularly to the southeast, the unit may be silty in part, or even contain distinct and identifiable siltstones that are capable of delivering marginal quantities of oil and gas.

II.A.1.f UNDIFFERENTIATED MISSISSIPPIAN AND PENNSYLVANIAN CLASTICS

In eastern Ohio the Mississippian and Pennsylvanian section above the Cuyahoga shale is comprised of alternating layers of shale, siltstone, and sandstone. Cut-and-fill features abound. The Pennsylvanian contains multiple beds of mineable coal. Being the youngest and shallowest of formations in eastern Ohio, they were among the earliest developed for oil and gas production. Their heyday had passed by the time wireline logging was introduced to the Appalachian Basin, and good wireline coverage over these units is thin. Most of the good detailing of the Mississippian and Pennsylvanian rocks has been an outgrowth of mapping associated coal beds.

II.A.2 - Characteristics of the Injection and Confining Zones

II.A.2.a - Injection Zone

The injection zone, being considered that portion of the wellbore below the injection string packer that is exposed to injected fluid, is the entirety of the openhole section. In the Buckeye Brine No. 1 Adams, the packer is set in the base of the Black River limestone at a depth of 5898 ft. Accordingly, the injection interval includes, from top to bottom, the Gull River, Glenwood shale (Lower Chazy and Wells Creek), Rose Run sandstone, Copper Ridge dolomite, Copper Ridge "B", Lower Copper Ridge dolomite, Conasauga dolomite and shale, Rome dolomite, and the Mt. Simon sandstone.

The total depth in the No. 1 Adams is 7305 ft. and cut an estimated 8-10 ft. into the Precambrian. The thickness of the injection interval from the base of the packer to total depth is ostensibly 1472 ft. However, prior to any testing, an approximately 20 ft. thick cement plug was set over the Precambrian, reducing the injection interval to 1452 ft.

The discussion that follows presents the general characteristics of each unit. So as to not mire the dialogue in details of possible lithology changes across the breadth of the State, these comments are generally meant to imply a 25-miles radius beyond the AOR, unless otherwise noted.

The Gull River is a regionally recognized unit that is composed of a dense, non-porous, non-permeable, micritic to microcrystalline limestone.

In a manner similar to the Gull River, the underlying Lower Chazy and Wells Creek units (commonly referred to collectively as Glenwood) are dense, non-porous, non-permeable rocks with excellent lateral continuity. Whereas the Lower Chazy is an argillaceous limestone with included shale, the Wells Creek is an argillaceous dolomite with included shale. Both can be easily traced in any direction.

Within 25 miles to the west, both the Rose Run and Copper Ridge terminate unconformably or are otherwise reduced by erosion against the regional Knox unconformity. Elsewhere, north and south, and to the east, each is laterally continuous and is of more or less predictable, if not constant, character. The Rose Run is dominated by non-porous dolomite, but includes up to five identifiable sand bodies that produce oil and gas under favorable conditions, particularly where erosional remnants of the Rose Run poke into the overlying Glenwood shale so as to ensure lateral sealing against fluid migration.

Downdip (east) from the AOR, the Rose Run sands become finer textured and better cemented, substantially reducing any reservoir qualities. The upper portion of the Copper Ridge is arenaceous and, like the Rose Run, may produce oil and gas in its subcrop zone to the west. Generally the lower portion of the Copper Ridge has little or no porosity and gives no evidence of permeability.

The Copper Ridge "B" is distinctive on logs and on samples for its high gamma-ray signature due to included clay and shale content. Within the area of description, the Copper Ridge is insufficiently porous to offer viable reservoir opportunities, despite wireline logs that in some instances generate an optimistic view of the unit.

Encountered as a massive, clean dolomite, the Lower Copper Ridge (LCR) is easily recognized in Coshocton and adjacent Counties. The upper portion of the LCR is commonly sucrosic, and well logs may indicate some manner of porosity. During drilling, the LCR commonly gives up at least some measure of fluid, validating observations of texture in the cuttings and values generated by the well logs. In local testing the unit has shown sufficient porosity and permeability to receive injected fluids, but it is not known if this trait is constant through Coshocton and adjacent Counties.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. These sands are commonly capable of receiving at least some injected fluid, but not enough wide-ranging penetrations and testing to determine the extent of reservoir conditions in these sandstones. The upper part of the Conasauga is a dense, argillaceous dolomite that is not considered to have reservoir potential.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Porosity development may be poor to excellent, but is invariably subtle and not easily or accurately quantified with wireline logs. The best porosity is developed within the uppermost 100 ft. of the unit and is linked to an end-of-Rome erosional surface.

The Mt. Simon is ubiquitous across Ohio, but its character changes from west to east. Along the western edge of the State it is a fine to coarse-grained sand, typically with good porosity and permeability. To the east the sand becomes increasingly fine, the degree of cementation increases markedly, and reservoir quality suffers. In eastern Ohio, Mt. Simon penetrations can generate favorable-appearing porosity on wireline logs that fails to translate into viable reservoir (Wickstrom, et al., 2011).

II.A.2 b - Confining Zone

The confining zone is considered to be that portion of the wellbore above the injection string packer. In this application the confining zone is approximately 2000 ft. thick and consists of 650 ft. of Ordovician limestones and 1400 ft. of Ordovician shale. The carbonate section is frequently penetrated in the quest for oil and gas, is well documented by wireline well logs, and is well understood by drillers and geologists who attend the process of exploration drilling. The shale portion is familiar, but not extensively studied or reported.

The specific formations included in this confining zone, from bottom to top, are the Black River and Trenton limestones, and the overlying Point Pleasant, Utica, Cincinnatian, and Queenston shales.

The approximately 580 ft. thick Black River is a massive, uniformly dense, non-porous, non-permeable, micro- to very finely crystalline limestone. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale. Lateral continuity is excellent.

The uppermost carbonate unit in the Ordovician section is the approximately 60 ft. thick Trenton limestone. It is composed of a very fine to coarsely crystalline limestone, and is abundantly fossiliferous at the top, becoming less so toward the bottom. Portions of the unit may be argillaceous or contain very thin stringers of black shale. Lateral continuity is good, any variations being vested primarily in minor thickness changes.

The Point Pleasant and Utica shales are herein discussed together. Both are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of about 250 ft. Their specific lithologies range from argillaceous limestone to calcareous shale. Fossil shell beds may be present, particularly in the Point Pleasant. The Utica, in particular, can be arenaceous. Because of the included carbonate and quartz, the rocks are relatively hard. The hardness may present drilling problems, but it also provides for a rock that responds very well to the hydraulic fracturing necessary for extracting hydrocarbons. Lateral continuity is good and, absent any hydraulic or natural fracturing, the Point Pleasant and Utica are considered impermeable.

The Cincinnatian is an approximately 750 ft. thick section of gray shale. Because few wells are drilled deep enough to reach the Cincinnatian and because it has no known commercial value, little attention has been paid to the unit. It remains poorly understood and poorly described. Where the Cincinnatian has been reached by the drill, it yields no shows of any kind and is thus regarded as impermeable and barren of fluids. Lateral continuity is excellent.

The Queenston is an approximately 400 ft. thick red, silty shale. The boundary between the Queenston and the underlying Cincinnatian is transitional. Having no commercial value, the Queenston is rarely given more than a cursory look, but based on drilling observations, it is considered to be an impermeable, non-reservoir rock.

References cited:

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Sclucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio.

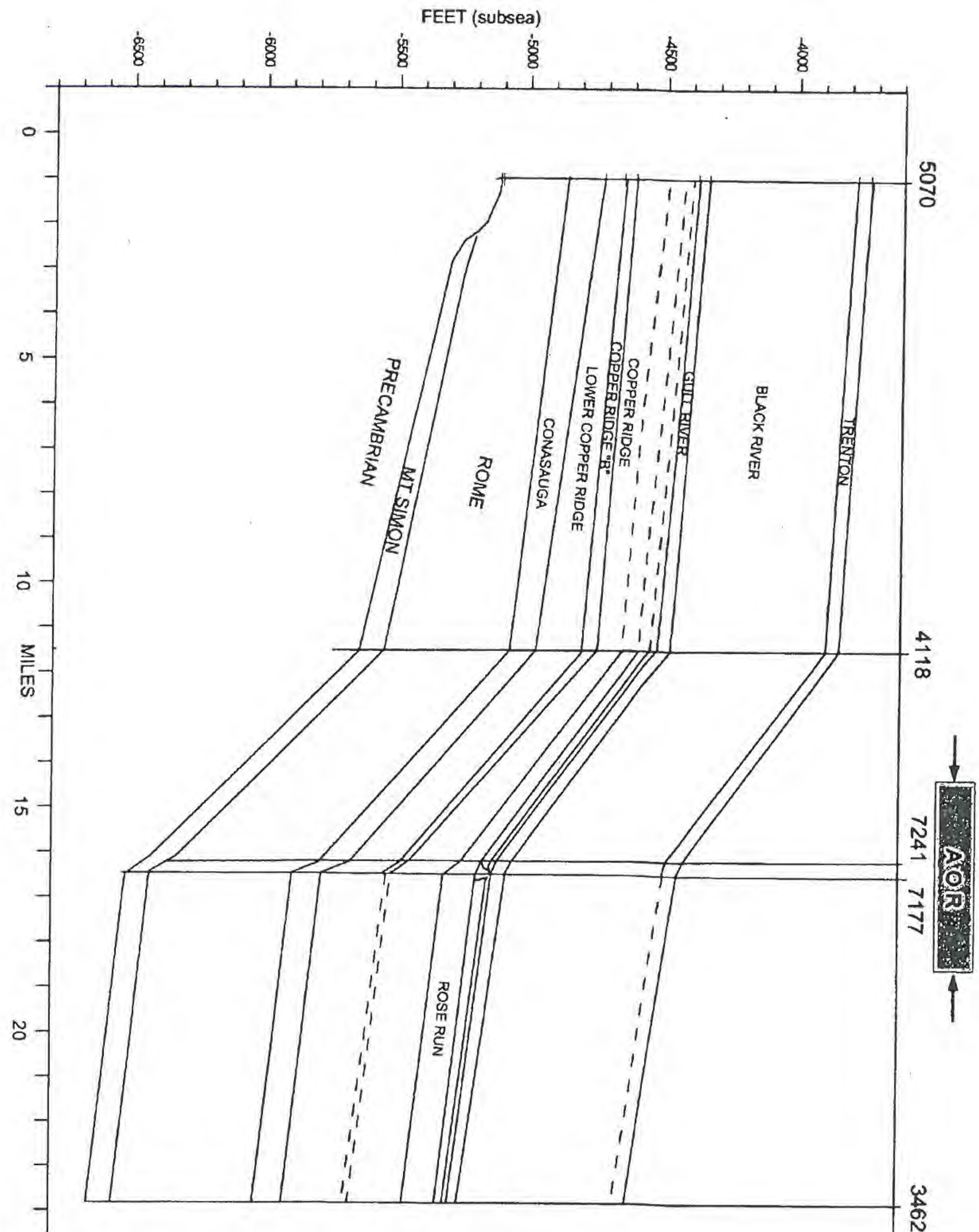


Figure II.A.3.02 - North-South structural section traversing the Area of Review and passing through the Buckeye Brine facility

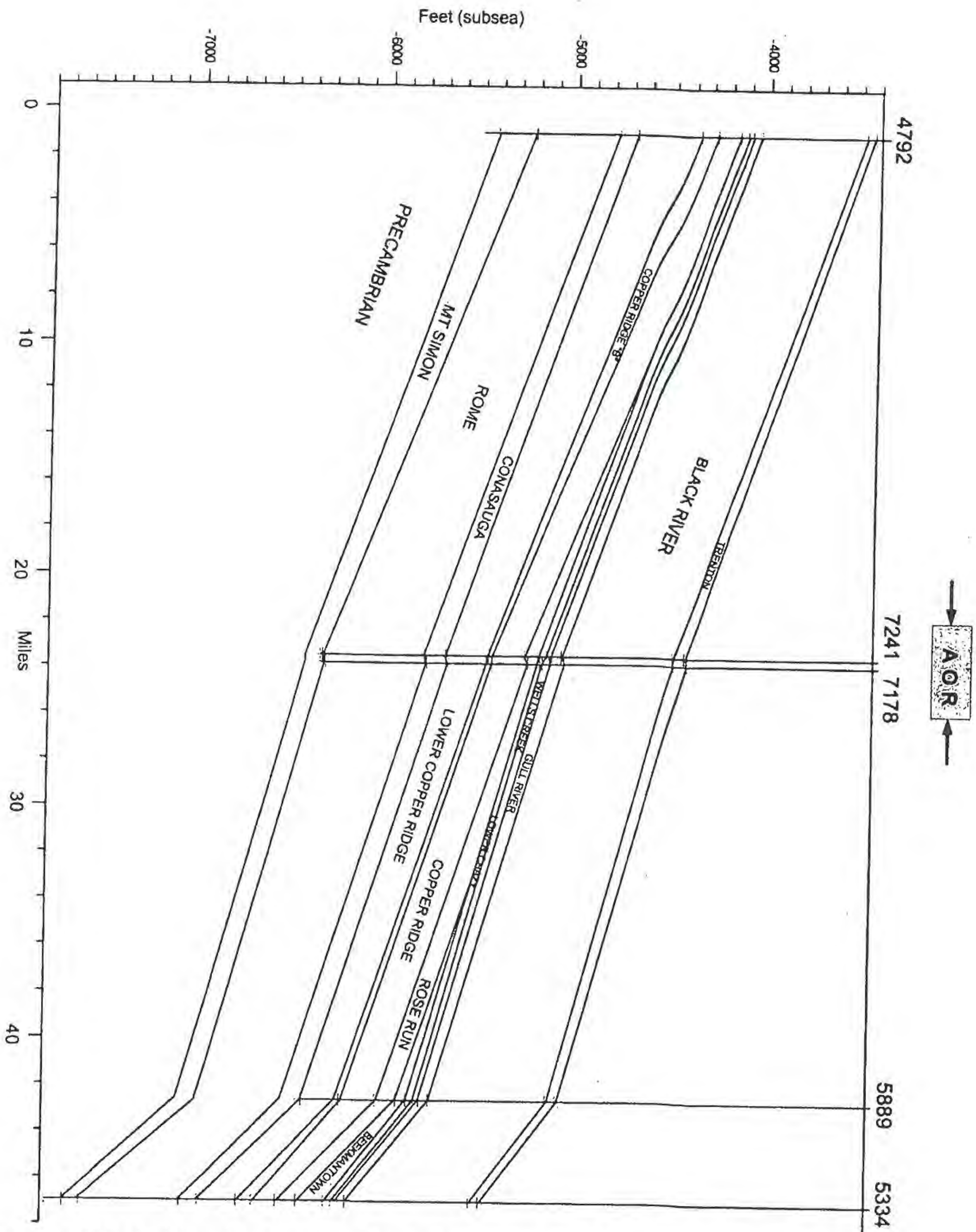


Figure II.A.3.03 - West-East structural section traversing the Area of Review and passing through the Buckeye Brine facility

Figure II.A.4.02 Map showing key structural features on and bordering the Ohio Platform

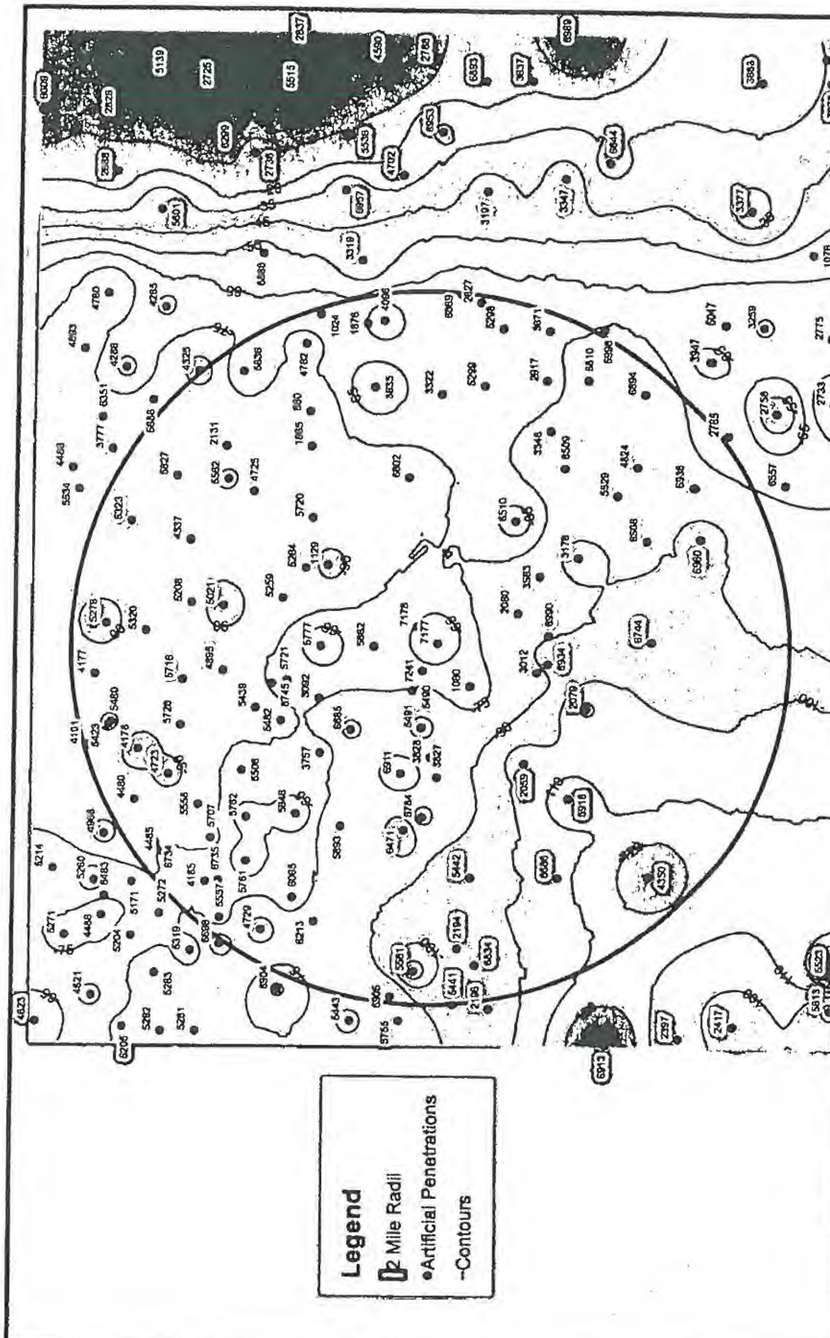


Figure II.A.4.03 - Structure map showing the manifestation of the Cambridge Arch on the top of the Berea sandstone

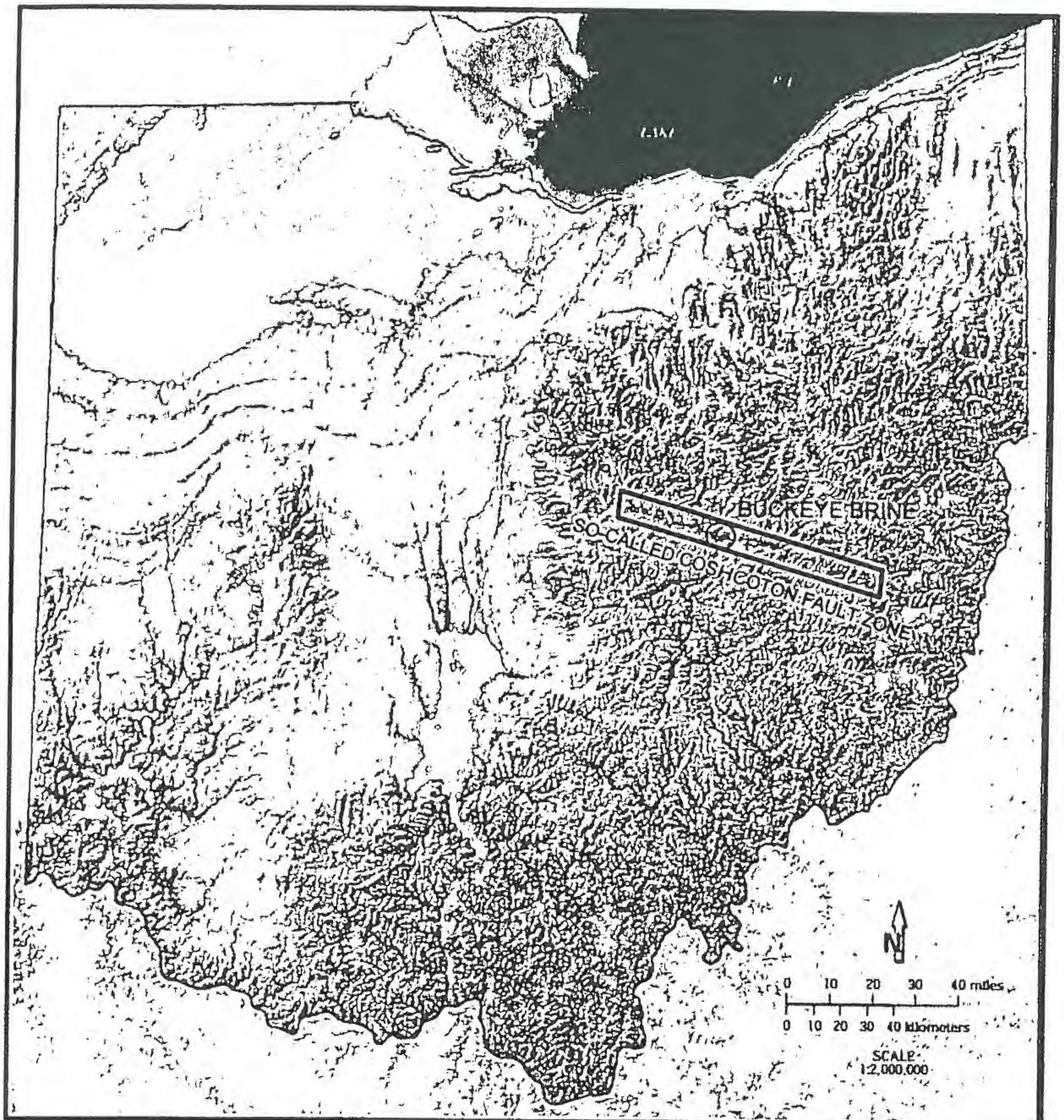


Figure II.A.4.04 - Shaded relief map by the Ohio Geological Survey shows the faint surface trace that is the basis for the Coshocton Fault Zone.

11.B LOCAL GEOLOGY

II.B.1. LOCAL PHYSIOGRAPHY AND BEDROCK

II.B.1.a. Physiography

Buckeye Brine's facility is 2 miles north of the city of Coshocton, and 0.6 miles north of the Tuscarawas River. Downstream from the facility, the smaller Walhonding River joins the Tuscarawas River on the north side of Coshocton where the two form the Muskingum River.

North of Coshocton, the local land surface is dominated by a flat, mile-wide incised valley that contains the meandering Tuscarawas River. Near the Buckeye facility the river is at an elevation of 740 ft. The valley and the lower slopes of the adjacent hillsides are cut into the Pennsylvanian Pottsville Group, and the hillsides themselves are topped with nearly a full section of Allegheny Group. On the north and south sides of the river, tributaries tend to be short. Lamborn (1954) described these tributaries as immature.

II.B.1.b Bedrock Geology

The Tuscarawas River has been incised into the Pennsylvanian Allegheny and Pottsville Groups, which have a combined thickness of about 300 ft. Total relief on the local topography is approximately 270 ft.

The hilltops on either side of the Tuscarawas River are topped with a nearly full section (140 ft. out of 150 ft.) of Pennsylvanian Allegheny shales, siltstones, and clays. The unit also includes Clarion, Kittanning, and Freeport coals. The Middle Kittanning has been mined from the surface and subsurface north of the Buckeye facility.

The river is cut into the Pottsville, and that same series of sediments form the bases of hills that border the valley. The lithology of the Pottsville is similar to that of the overlying Allegheny, both presenting a series of cyclothems. Above the valley floor, the Pottsville exposes the Brookville, Tionesta, Bedford, and Mercer coals, none of which have been mined locally.

An estimated 150 ft. of detritus and glacial outwash fill the valley floor, not counting the aforementioned terraces. On this basis it may be surmised that the river at one time had cut into Mississippian sediments.

Reference cited:

Lamborn, R., 1954, Geology of Coshocton County: Ohio Division of Geological Survey, 245 p. Plus Map.

II.B.2 LOCAL GLACIATON

Neither the Wisconsin nor Illinoian ice sheets advanced far enough south and east through Ohio to impinge on the AOR. In like manner, there is no evidence that either of those glacial events had a meaningful effect on pre-Wisconsin/Illinoian drainage patterns.

Meltwater from both events emplaced substantial outwash deposits in the Tuscarawas River Valley as far east as Newcomerstown, 10 miles east of the AOR. The most visible of these deposits form broad, 20-60 ft. high terraces on either side of the river, and the less obvious deposits constitute the mile-broad, flat expanse of river bed fill material.

Any possible evidence of the earlier Kansan or Nebraskan ice ages in eastern Coshocton Co. is generally considered too suspect to support declarative statements as to their character and effect.

II.B.3 Groundwater Resources and Lowest USDW

The deepest underground source of drinking water (USDW) is defined (<10,000 ppm TDS) by the U.S. EPA. In the Coshocton area and the Area of Review (AOR) this is based on work done by Vogel (1982), which cited the Black Hand sandstone as the base of the USDW. Matchen (2006), however, maps the Black Hand as an elongated sand body trending north-south and lying about 10 miles west of the (AOR) and this throws into question the precise stratigraphic identification of the USDW reservoir. Nonetheless, as later mapped by Riley (2012), the so-called Black Hand is cited as the deepest USDW and covers much of eastern Ohio. In the area of review, Riley's base of USDW lies at a depth of about 330 ft. from the surface (Fig. V.B.3.a-01 and Fig. V.B.3.a-02).

The depth to the USDW notwithstanding, culture in the AOR is largely confined to the valleys, where local, domestic water is supplied chiefly by shallow domestic wells drilled into the sand and gravel that fills the Tuscarawas River valley. Typically these wells are drilled and cased to a depth of 50-75 ft. and generate excellent yields that average about 35 gallons per minute (gpm). On its map "Yields of the Unconsolidated Aquifers of Ohio," the Ohio Division of Water Resources attributes these valley-drilled wells with potentials in excess of 500 gpm. Static water levels are about 25 ft. below grade. Although a few wells have been drilled to depths of over 100 ft., their yields and static levels are comparable to those of the shallower wells.

On higher ground, away from the valley, water may be obtained from perched sandstone aquifers contained within the Allegheny Group sediments. Yields and static levels are reported as being comparable to those encountered from the sands and gravel in the river valley.

To a lesser degree, municipal (Coshocton) water is supplied to certain larger public and private facilities such as the Coshocton Co. Regional Airport, and the Coshocton City and County golf course, the Coshocton Christian Tabernacle church, and retail establishments close by Rt. 36.

Drilling and completion records for domestic water wells are maintained by the Ohio Department. Natural Resources Division of Water and are available online. The most recently drilled wells are typically the most complete and accurate records. Wells that predate permit requirements may or may not be represented by a driller's record. Instances of more than one well using the same well identification number are common. All known wells have been attributed with geographic co-ordinates by the Division of Water.

Other than nominal descriptors such as "sandstone," or "gravel," the unconsolidated reservoirs are undifferentiated, either in the formally submitted water well records or published literature. Similarly, there has been insufficient subsurface work done to authoritatively differentiate the several sandstone and siltstone reservoirs. For these reasons it is not possible to confidently construct piezometric maps for the various units.

In a more regional setting, the AOR is contained within the Tuscarawas River Valley drainage basin. The United States Geological Survey (USGS) discussed subsurface water flow in the vicinity of the AOR in its "Summary of Hydrologic Data for the Tuscarawas River Basin, Ohio, with an Annotated Bibliography (2010-2015)." After recounting the availability of water well records from the Ohio Dept. Natural Resources Division of Water, and recorded water levels in domestic wells contained therein, the USGS made the following observations:

1. Groundwater flow is generally from the upland bedrock areas down into the sand- and gravel-filled valleys (general flow directions can be inferred by drawing flow lines perpendicular to contours anywhere on the map (Figure III.B.3.a.03).
2. The water-level surface mimics topography and generally follows surface-water flow directions. Topographic contours were used to refine (but not define) the contouring of the water-level elevations encountered in drilled wells, so this characteristic may be an artifact of the manner in which the contours were drawn.
3. In several areas data were too sparse to develop a water level surface.

The findings of the USGS adhere to the commonly accepted observation that water levels, and by extension, water flow, follow the surface contour of the land. As applied to the vicinity Buckeye Brine facility, a large portion of the local groundwater will flow east to west through the Tuscarawas River valley itself, this mostly south of the facility. A lesser amount of water will be derived from the higher ground north of the facility, the water moving in a south to south-southeast direction before mixing with the water in the river valley sediments and proceeding westward. With specific reference to the Buckeye Brine facility, subsurface water movement across the property will be primarily in a south-southwest direction across the property (Figure II.B.3.a.04). Actual land surface profiles in the vicinity of the facility are illustrated in Figure III.B.3.a.05 and indicate the south and southwest components to be the primary contributors to determining the direction of ground water flow.

II.B.5 LOCAL STRATIGRAPHY

The Buckeye Brine (Buckeye) No. 1 Adams (API #33103427177000), which is located in the center of the AOR, serves as the type log for this discussion (Fig. II.B.5.01). Unless otherwise noted, depths and thicknesses will be referenced to that well.

PRECAMBRIAN

Based on drill cuttings in the AOR, the Precambrian is granitic in composition. Drilling experiences and wireline logs suggest that the upper portion of the Precambrian may be present as a "granite wash," either a highly weathered and/or detrital form of the native rock that is relatively easy to drill.

CAMBRIAN PERIOD

Mt. Simon/Basal Sand

The 80 ft. thick Mt. Simon is the lowermost of the Cambrian units. Until very recently the Mt. Simon was considered an omnipresent reservoir across Ohio. However, in eastern Ohio it is noticeably finer textured and contains a higher percentage of associated dolomite than it does in central and western Ohio. These factors work against its role as a reservoir, and the Mt. Simon continues to degrade further to the east. An isolated injection test of the Mt. Simon in the Ohio Geological Survey #1 CO2 (API #34157253340000), 20 miles east of the AOR in Salem Twp., Tuscarawas Co., similarly determined there was essentially no injection potential (Wickstrom, et al, 2011).

What is called the Rome dolomite (Janssens, 1972) in eastern Ohio is considered as having two identifiable parts, a lower arenaceous dolomite section and an upper pure dolomite section.

The approximately 40 ft. thick basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone. It is an arenaceaous dolomite with a fine-textured sand content that decreases upward. Some thin (<4 ft.) framework sandstones may be present. None of this lower section has been found to have enough porosity or permeability to act as a reservoir. The upper 510 ft. of the Rome is chiefly a micro-crystalline dolomite with some portions exhibiting a slightly sucrosic texture. Supplies of clastic admixtures were cut off. The upper boundary of the Rome is considered an unconformity surface. Thin (to 3 ft.) vugular porosity zones occur at random horizons within the uppermost 100 ft. of the unit. These porosity zones are interpreted as a collapsed paleo-karst system.

Throughout much of the literature the Conasauga has been identified as a shale, though it is in fact an interesting sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. On resumption of deposition in post-Rome time, thin, erratically developed sandstones were first deposited. Close comparison of the Conasauga sands in different wells suggests they are overlapping and interfingered, but individual beds may have limited lateral continuity.

The 250-ft. thick Lower Copper Ridge dolomite in the AOR was laid down during a period of constant carbonate deposition is a warm shallow sea. It is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. Locally, portions may be sucrosic, particularly near the top. Density and neutron logs typically generate favorable porosity values. Various tests have suggested a small degree of transmissivity, though not as much as would be inferred from the logs. The Lower Copper Ridge in Coshocton and adjacent Counties commonly make water during drilling, especially from the upper half of the unit, which is considered injection reservoir.

The informally named Copper Ridge "B" is a 20 ft. thick section comprised of argillaceous dolostones and gray shales. The base of the "B" zone is commonly laced with shell fragments and minor amounts of quartz sand, suggesting an unconformity surface or a shallow still-stand. The "B" zone is not known to yield oil, gas, or water in the AOR.

Like the Lower Copper Ridge, the 200 ft. thick (upper) Copper Ridge dolomite the AOR is composed of a relatively pure microcrystalline to finely crystalline dolomite, but differs in that the top of the unit is arenaceous as it transitions upward into the Rose Run sandstone. None of this upper sandy portion is developed as a framework sandstone. Despite the appearance of porosity on well logs, there is no apparent permeability to back it up.

In the AOR the Rose Run was partially eroded away in post-Knox time so that only about 70 of its full 100 ft. thick section is present. The lower sands that are present represent a still-shallowing landscape, a continuation of late Copper Ridge sedimentation, and are not as coarse of texture or as well sorted as the missing upper Rose Run sands. The reservoir properties of these lower sands, as depicted on wireline logs, are good, but in practice fail to offer a viable combination of porosity and permeability.

ORDOVICIAN PERIOD

Within the AOR, the Beekmantown was removed from the Knox Group before the top of the underlying Rose Run was eroded away. The Beekmantown will not be present in local wells unless it is contained in a Knox erosional remnant with more than enough height to contain the Rose Run.

Considerable confusion attends the nomenclature of the Wells Creek and Lower Chazy shales, which are sometimes collectively or singly referred to as the Glenwood. As discussed herein, the two are differentiated on the basis of color and lithology. The 30 ft. thick Lower Chazy is a dense, micritic, argillaceous limestone with interbedded gray shale. The underlying Wells Creek is 45 ft. thick and is composed of a hard, dense, micritic, argillaceous dolomite with interbedded shale, the whole appearing light gray or in shades of green or pale blue. Both are slowly accumulated shelf carbonates with mingled clays.

Still in a shelf environment like the Lower Chazy, but with no clastics added in, the 50 ft. thick Gull River is composed of a uniformly dense and pure, impermeable micritic limestone.

Lihtologically similar to the underlying Gull River, the Black River is about 580 ft. thick in the AOR. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale.

The uppermost carbonate unit in the Ordovician section is the 60 ft. thick Trenton limestone. The product of a slightly deeper environment than the Black River, it can be abundantly fossiliferous toward the top and may contain clay admixtures or thin dark shale.

Continuing the trend of ever deepening water, the Point Pleasant and Utica are generically considered organic black shales. They have a combined thickness of about 240 ft. Their specific lithologies range from dark brown to black argillaceous limestone to calcareous shale. Fossil shell beds may be present, and the Utica, in particular, can be quartz rich.

The entire Cincinnatian-Queenston shale sequence is an approximately 1340 ft. thick Together these units chronicle the prolonged accumulation of clay and silt in an increasingly shallow marine environment. The Cincinnatian is gray shale that grades upward into the silty red Queenston, and culminates with a regional erosion surface.

SILURIAN PERIOD

The Silurian was ushered in with deposition of nearly 200 ft. of shallow water clastics. The first was the Medina, which is irregularly developed across Ohio. In the AOR the Medina is only 13 ft. thick. Developed as a clay-laced, quartz cemented silt, it is a barely recognizable marker bed.

The 155 ft. thick Cataract Group includes the informally named Clinton sandstone. Gray shales appear above and below the Clinton, the whole demonstrating a continual influs of sediment and constantly fluctuating water depths. The Cataract is capped with a distinctive red, hematitic oolitic limestone.

In the AOR the overlying shale is 60 ft. thick, and the especially fissile shale below the Clinton is about 60-70 ft. thick. The Clinton itself is developed as a series of white, interlayered, very fine-grained to silty quartz sands with a silica cement. Porosity and permeability is low, not often exceeding 10% and 10 mD, respectively. Individual beds may be as much as 30 ft. thick, but more typically are thin, 5-20 ft. thick. In the aggregate, the net sand thickness can be 5-40 ft. All of this conspires to form a wide-ranging assortment of stratigraphic oil and gas traps. Nearly everywhere it is drilled, some manner of oil and gas is encountered in marginal to paying quantities.

The common Packer Shell moniker for the Dayton Formation (Fm.) derives from century-ago cable tool drillers who used the dolomite bed(s) as a casing seat when drilling to the Clinton sandstone. Depending on locale, the unit appears as one to three thin, transgressive lenses of micro- to coarsely crystalline, slightly fossiliferous dolomite.

The 120 ft. thick Rochester shale is the last significant influs of clastics during the Silurian. It is a mix gray shale and dense, blocky, red and green marls, the latter occurring primarily in the lower half of the unit.

The Lockport, more commonly referred to as the Newburg, is a 315 ft. thick transgressive accumulation of carbonates that may range from dolomite to limestone, the dolomite mineralogy predominating, as is the case in the AOR.

Sedimentation in eastern Ohio during the late Silurian took place in a restricted, evaporitic basin that left a 505 ft. thick sequence of dolomite and anhydrite that contains a minor amount of thin gray shale. East and north of the AOR, salt is major component of the Salina. The western limit of those salts is about 3 miles east of the Buckeye facility.

DEVONIAN PERIOD

The 180 ft. thick Bass Island and Helderberg units are the basal members of the Devonian sequence. Both have a limestone-dominant lithology, but both contain thin (to 15 ft.) dolomite sections. Both units are bounded above and below by unconformities.

As discussed herein, the 150 ft. thick Onondaga, informally referred to as the Big Lime, is a 135 ft. thick limestone plus the underlying 15 ft. thick Oriskany sandstone. The Oriskany thins from east to west and sits unconformably on the underlying Helderberg. Though the Oriskany produces gas 5 miles north of the AOR, within the AOR it has low porosity and permeability, and lacks an apparent trap.

The approximately 1540 ft. thick Ohio shale sequence contains numerous sub-units, most of which are subtle variations of gray shale. Some non-productive black shales are among the basal units.

The Berea sandstone in the AOR is a thin, shallow water, blanket type deposit that is composed of a silty, very fine-grained, mechanically cemented gray sandstone with modest porosity (to 10%) and permeability. Within the AOR it is about 20 ft. thick.

MISSISSIPPIAN PERIOD

Referred to by cable tool drillers as the "Coffee shale" for its distinctively rich brown color, the 40 ft. thick Sunbury shale is organic, slightly silty, and breaks easily under the drill. Although it does not produce oil or gas by itself, it is at least one source for the oil and gas trapped in the underlying Berea sandstone.

Locally, the approximately 150 ft. thick Cuyahoga is composed entirely of gray shale. Elsewhere in the State, particularly to the southeast, the unit may be silty in part, or even contain distinct and identifiable siltstones that are capable of delivering marginal quantities of oil and gas.

The Mississippian and Pennsylvanian section above the Cuyahoga shale is comprised of about 500-800 ft. of alternating layers of shale, siltstone, and sandstone, some shaped by cut-and-fill features. In the aggregate, these rocks are poorly documented, rarely given notation on drilling records or described from cuttings, and are almost never characterized with wireline logs.

References:

Riley, R. A., 2012, Map EG-6, Elevation Contours on the Base of the Deepest Underground Sources of Drinking Water in Ohio: Columbus, Ohio Department of Natural Resources, Division of Geological Survey, 1 Map (Scale 1:500,000).

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Sclucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey

No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio

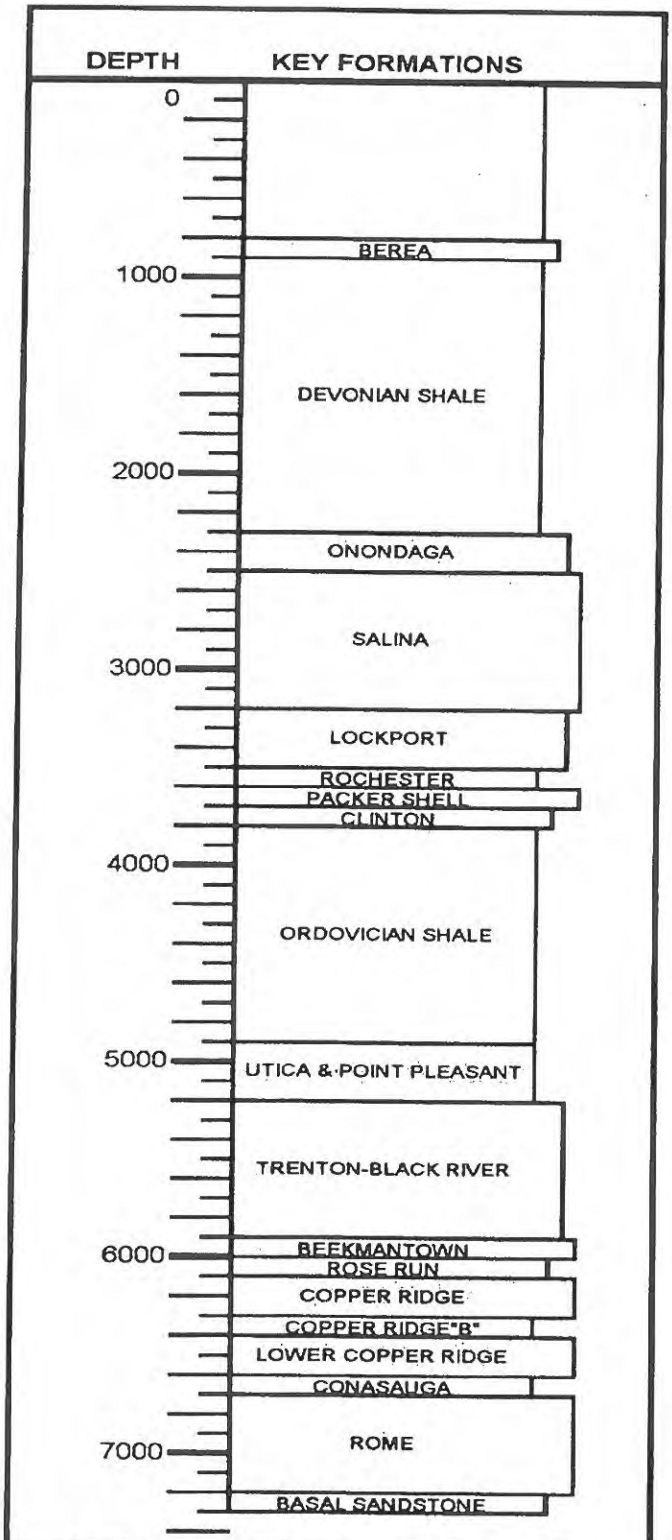


Figure II.B.5.01 - Stratigraphic section showing the key formations and sub-units in the Area of Review, and their approximate drilling depth.

II.B.6. CHARACTERISTICS OF THE INJECTION ZONE, CONFINING ZONE, AND THE LOWERMOST USDW

II.B.6.a Lowermost USDW

The deepest USDW is defined (<10,000 ppm TDS) by the U.S. EPA. In the Coshocton area and the AOR this is based on work done by Vogel (1982), which cites the Black Hand sandstone as the base of the USDW. Matchen (2006), however, maps the Black Hand as an elongated sand body trending north-south and lying about 10 miles west of the AOR and throws into question the precise stratigraphic identification of the USDW reservoir. Nonetheless, as later mapped by Riley (2012), the so-called Black Hand is cited as the deepest USDW and covers much of eastern Ohio. In the AOR, Riley's base of USDW lies at a depth of about 330 ft. from the surface (Fig. II.B.6.a-01 and Fig. II.B.6.a-02).

The depth to the USDW notwithstanding, local, domestic water is supplied chiefly by shallow domestic wells drilled into the sand and gravel that fills the Tuscarawas River valley. Typically these wells are drilled and cased to a depth of 50-75 ft. and generate excellent yields that average about 35 gallons per minute (gpm). On its map "Yields of the Unconsolidated Aquifers of Ohio," the Ohio Division of Water Resources attributes these valley-drilled wells with potentials in excess of 500 gpm. Static water levels are about 25 ft. below grade. Although a few wells have been drilled to depths of over 100 ft., their yields and static levels are comparable to those of the shallower wells.

On higher ground, away from the valley, water may be obtained from perched sandstone aquifers contained within the Allegheny Group sediments. Yields and static levels are reported as being comparable to those encountered from the sands and gravel in the river valley.

For these reasons there has been little need or desire to do detailed characterization of water sources deeper than the valley sand and gravel fill. Cable-drilled wells, generally known for the most complete descriptions of the drilled rock, are characteristically afflicted with a disinterest in shallow water-bearing zones except as they might require a casing string. Rotary-drilled wells do not use shallow cuttings except to set casing points, and no records of rock type are kept. Wireline logs acquire through fresh water bearing zones are wholly incidental to other objectives and in a best-case scenario consist of a gamma ray-neutron suite.

The illustrated log segment (Fig. II.B.6.a-02) highlights what is thought to be the unit attributed as being the lowest USDW per Riley (2012). It is contained in the upper Mississippian section. It and adjacent beds consist of shale silty sandstone. Based on the few records left by cable drillers, none of those zones are known to possess especially good porosity or permeability that would truly lend them to the purpose of supplying domestic water.

II.B.6.b Confining Zone

The Confining Zone is considered to be that portion of the wellbore above the injection string packer. In this application the confining zone is approximately 2000 ft. thick and consists of 640 ft. of Ordovician limestones and 1400 ft. of Ordovician shale. The carbonate section is frequently penetrated in the quest for oil and gas, is well documented by wireline well logs, and is well understood by drillers and geologists who attend the process of exploration drilling. The shale portion is familiar, but not extensively studied or reported.

The specific formations included in this confining zone are, from bottom to top, the Black River and Trenton limestones, and the overlying Point Pleasant, Utica, Cincinnatian, and Queenston shales.

The approximately 580 ft. thick Black River (Fig. II.B.6.b.01) is a massive, uniformly dense, non-porous, non-permeable, micro- to very finely crystalline limestone. The upper portion of the unit may contain one or more thin (to 4 ft.) bentonite beds, some of which are traceable across much of the State. The lowermost 50 ft. of the unit is argillaceous and contains some thin, black stringers of slightly calcareous shale. Excepting the bentonite beds and the lower shaly portion, the Black River limestone appears textbook on wireline logs, having a nearly ideal 2.70 g/cc density throughout and an approximately 4.5 PE value. Lateral continuity is excellent.

The uppermost carbonate unit in the Ordovician section is the approximately 60 ft. thick Trenton limestone. It is composed of a very fine to coarsely crystalline limestone. It is abundantly fossiliferous at the top, becoming less so toward the bottom. Portions of the unit may be argillaceous or contain very thin stringers of black shale. Because of this mixed composition, and particularly the inclusion of clays, the unit is not readily or accurately quantified with conventional porosity-driven log suites. Lateral continuity is good.

The Point Pleasant and Utica shales (Fig. II.B.6.b.02) are herein discussed together. Both are generically considered organic black shales and are recognized chiefly for their production of gas and associated liquid hydrocarbons along the eastern edge of Ohio. They have a combined thickness of about 240 ft. Their specific lithologies range from argillaceous limestone to calcareous shale. Fossil shell beds may be present, particularly in the Point Pleasant. The Utica, in particular, can be arenaceous. Because of the included carbonate and quartz, the rocks are relatively hard. As is the case for the underlying Trenton, this mixed composition, plus the inclusion of low-density hydrocarbon, is beyond the scope of conventionally-run density logs. Advanced lithology logs may better characterize the unit, but none have been run in the AOR. Lateral continuity is good and, absent any hydraulic or natural fracturing, the Point Pleasant and Utica are considered impermeable, and have good lateral continuity.

The Cincinnatian is an approximately 750 ft. thick section of gray shale. Because few wells are drilled deep enough to reach the Cincinnatian and because it has no known commercial value, little attention has been paid to the unit. It remains poorly understood and poorly described. Where the Cincinnatian has been reached by the drill, it yields no shows of any kind and is thus regarded as impermeable and barren of fluids. Lateral continuity is excellent.

The Queenston is an approximately 400 ft. thick red, silty shale. The boundary between the Queenston and the underlying Cincinnatian is transitional. Having no commercial value, the Queenston is rarely given more than a cursory look, but based on drilling observations, it is considered to be an impermeable, non-reservoir rock. Lateral continuity appears excellent.

based on neutron porosity, the LCR has 81 net ft. of 7.8% average porosity. Although these are impressive numbers, testing suggests that the LCR is only capable of modest injectivity.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. In the No. 1 Adams these sands have an average density porosity of 6.8% over a 4 ft. net sand thickness. Some minor injectivity may be attributable to these sands. The upper portion of the Conasauga is an argillaceous dolomite that cannot be attributed with any viable porosity.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Neutron porosity across the approximately 37 ft. of what is thought to be sucrosic porosity averages 7.1%. Testing indicates that injectivity across these zones is limited. One or more zones of vugular porosity, thought to be the vestige of a collapsed paleo-karst topography, may be present in the upper 100 ft. of the section. This type of large-pore porosity cannot be accurately quantified with wireline logs, but testing shows that injectivity may be good to excellent.

II.B.6.d Injection Interval

The Injection Interval in the Buckeye Brine No. 1 Adams is considered that portion of the wellbore below the injection string packer that is exposed to injected fluid, that being the entirety of openhole section. In the Buckeye Brine No. 1 Adams the packer is set in the base of the Black River limestone at a depth of 5898 ft. Accordingly, the injection interval includes, from top to bottom, the Gull River, Glenwood shale (Lower Chazy and Wells Creek), Rose Run sandstone, Copper Ridge dolomite, Copper Ridge "B", Lower Copper Ridge dolomite, Conasauga dolomite and shale, Rome dolomite, and the Mt. Simon sandstone. The thickness of the injection interval from the base of the packer to top of a cement plug in the lowermost portion of the wellbore is approximately 1452 ft. The discussion that follows presents the general characteristics of each unit.

The Gull River is a regionally recognized unit that is composed of a dense, non-porous, non-permeable, micritic to microcrystalline limestone.

In a manner similar to the Gull River, the underlying Lower Chazy and Wells Creek units (commonly referred to collectively as Glenwood) are dense, non-porous, non-permeable rocks with excellent lateral continuity. Whereas the Lower Chazy is an argillaceous limestone with included shale, the Wells Creek is an argillaceous dolomite with included shale. Both can be easily traced in any direction.

The Rose Run sandstone is dominated by non-porous dolomite, but includes up to five identifiable sandstone bodies that, locally, are composed of a well-cemented, fine-grained quartz sand. The texture and degree of cementation work against an injection reservoir, and especially impinges on permeability. Density porosity, using a <2.1 PE cutoff, shows 27 net ft. of potential reservoir, but with an average density porosity of only 4.8%. There is no indication of injection into the Rose Run.

The lower portion of the 200 ft. thick Copper Ridge dolomite in eastern Ohio is composed of a relatively pure micro- to finely crystalline dolomite with a minor clay content. The upper portion is arenaceous and is transitional into the overlaying Rose Run sandstone. None of the sandy sections of the Copper Ridge translate to a framework sandstone, so neutron porosity is used to assess the Copper Ridge. On that basis, 143 ft. of the section exceeds 6% porosity and averages 7.6%. Wireline porosity does not necessarily mean injectable rock. Experience with the No. 1 Adams indicates the unit to be without injectablity.

The Copper Ridge "B" is distinctive on logs and on samples for its high gamma-ray signature due to included clay and shale content. Within the AOR, the Copper Ridge is insufficiently porous to offer viable reservoir opportunities, despite optimistic porosity indicators on wireline logs.

Encountered as a massive, clean dolomite, the Lower Copper Ridge (LCR) is easily recognized in Coshocton and adjacent Counties. The upper portion of the LCR is commonly sucrosic, and well logs may indicate some manner of porosity there. During drilling, the LCR commonly gives up at least some measure of fluid, validating observations of texture in the cuttings and the values generated by the well logs. Wireline logs indicate that, based on neutron porosity, the LCR has 81 net ft. of 7.8% average porosity. Although these are impressive numbers, testing suggests that the LCR is only capable of modest injectivity.

The Conasauga is a sequence of interbedded dolomite, argillaceous dolomite, and shale across most of eastern Ohio. Thin, erratically developed sandstones may be present in the lowermost 30-40 ft. of the unit. In the No. 1 Adams these sands have an average density porosity of 6.8% over a 4 ft. net sand thickness. Some minor injectivity may be attributable to these sands. The upper portion of the Conasauga is an argillaceous dolomite that cannot be attributed with any viable porosity.

The Rome, excepting an arenaceous basal section, is a massive, micro- to finely crystalline dolomite. The basal portion of the unit is upwardly transitional from the underlying Mt. Simon sandstone and has an upwardly decreasing sand content. The upper portion of the Rome may be sucrosic in part. Neutron porosity across the approximately 37 ft. of what is thought to be sucrosic porosity averages 7.1%. Testing indicates that injectivity across these zones is limited. One or more zones of vugular porosity, thought to be the vestige of a collapsed paleo-karst topography, may be present in the upper 100 ft. of the section. This type of large-pore porosity cannot be accurately quantified with wireline logs, but testing shows that injectivity may be good to excellent.

The 80 ft. thick Mt. Simon is a very fine to fine-grained quartz sand with included clays and a dolomite cement. In terms of simple analysis from well logs, density calculations show that the Mt. Simon has 60 net ft. of sand(stone) with an average porosity of 6.6% While these numbers are encouraging, testing of the No. 1 Adams has failed to indicate any injectivity. This is consistent with the emerging opinion of the Mt. Simon in eastern Ohio. An isolated injection test of the Mt. Simon in the Ohio Geological Survey #1 CO2 (API #34157253340000), 20 miles east in Salem Twp., Tuscarawas Co., similarly determined there was essentially no injection potential .

Reference cited:

Wickstrom, L. H., Riley, R. A., Spane, F. A., McDonald, Jas., Sclucher, E. R., Zody, S. P, Wells, J. G., and Howat, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO2 Well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio.

II.B.6.e Lower Confining Strata

The No. 1 Adams was drilled to a total depth of 7305 ft. and cut an estimated 8-10 ft. of the Precambrian. Prior to any testing, an approximately 20 ft. thick cement plug was set over the Precambrian, making the Mt. Simon the lowermost unit in the injection interval. The Precambrian is thus the lower confining structure.

Because of the short foothold in the Precambrian, no wireline log data was acquired over that part of the wellbore, and it remains unquantified. It is believed to be without measurable porosity of permeability.

The Mt. Simon in eastern Ohio commonly produces at least moderate porosity values on wireline logs, although those values are not known to translate to injectable porosity. Injection testing of the Buckeye Brine No. 1 Adams substantiated prior findings.

II.B.7 LOCAL STRUC TURAL CROSS-SECTIONS

Using wireline log data from wells within the AOR that were drilled into the injection interval, a north-south and a west-east cross section were constructed for the purpose of comparison to shallow (<4500 ft.) mapping and reconnaissance seismic acquired by Buckeye Brine.

Two versions of each section are presented. The structural section uses a sea level datum. The stratigraphic section uses a top-of-Trenton datum.

The structure sections show the expected southeastward dip, though the north-south line shows this more plainly. Both lines show the moderate undulation that is common at the top of the Knox Group (Rose Run), as well as Knox (Rose Run) erosional remnants that are common targets for oil and gas development. Of particular interest is the apparent structural difference between the No. 1 Adams and the No. 3 Adams.

The west-east stratigraphic section shows some eastward mild thickening of the individual units, as would be expected.

II.B.8 LOCAL STRUCTURAL GEOLOGY

A prominent surface lineament that passes close by Coshocton was originally referred to as the Coshocton Fracture Zone (Fig. II.B.8.01), and subsequent references have referred to it as the Coshocton Fault Zone. The control for the lineament was originally built from USGS digital elevation model files (Mason, 1999) and is visible on the Ohio Geological Survey's shaded elevation map. Attributed to surface fractures, it is speculated to be associated with deep-seated fracture systems. It remains poorly understood and is omitted from most maps that portray basement-influenced structure.

In reporting on the extensively researched Ohio Geological Survey No. 1 CO2 stratigraphic test (API# 3415725334) , 20 miles east of the Buckeye facility, it was reported that no regional extensive, deep-seated faults were identified within 25 miles of the test site (Wickstrom, et al., 2011)

A series of structure maps and an isopach were constructed from the available well control*. The structure maps included the Berea (Fig. II.B.8.02), Big Lime (Onondaga)(Fig. II.B.8.03), and Packer Shell (Dayton) (Fig. II.B.8.04) horizons. The isopach map presented the interval thickness from the top of the Big Lime to the top of the Packer Shell.

From the standpoint of constructing structure maps from well control, ground level elevations present a particular problem. Prior to the common usage of global positioning system (GPS) devices, a well's ground level elevation was typically derived from USGS 7.5-minute topographic maps. The accuracy of the derived ground level elevation that went into the records was dependent on the contour interval of the map, the skill and attention of the surveyor, changes to the original landform due especially to surface mining, and the driller's adherence to the surveyed location. In this Coshocton Co. area where surface mining is common, the relief is moderate to high, and the terrain highly dissected, derivative subsea values must be screened for probable accuracy. All this is to say the data quality is suspect. Judgment must be invoked to cull reasonable values from the spurious. Not all data points were utilized.

Isopach maps, not subject to the vagaries of ground level elevation, are considered to be derived from a less flawed data set.

Although the AOR employs a 2-mile radius, mapping was extended 3 miles east of the Buckeye Brine facility in order to determine the location of the Cambridge Arch.

The Berea structure clearly shows the rolled and uplifted anticline on the Berea that is the manifestation of the Cambridge Arch 3 miles east of the facility. A low area with a northwesterly orientation can be seen to pass close to the center of the AOR.

The low area seen running through the AOR on the Berea map reverses itself on the Big Lime structure and appears as a southeast-plunging nose. On the east edge of the AOR the Big Lime contour lines are more closely spaced, but show a down-to-the-east monocline in place of the shallower Berea anticline. Evidence of the Cambridge Arch is tenuous.

The structural forms seen on the Big Lime structure are mimicked on the Packer Shell structure. Whereas the relief across the breadth of the Big Lime nose was on the order of 20-25 ft., it is a more subtle 15-20 ft. on the Packer Shell surface and maintains the same orientation as seen on the Big Lime. The dip on the Big Lime has a maximum rate of approximately 80 ft./mi., but on the Packer Shell the dip is about 100 ft. per mile, at least part of which can be attributed to normal eastward thickening of all units.

The Big Lime-Packer Shell isopach is straightforward in showing a N35W trending isopach thin whose western edge passes through the Buckeye Brine facility. It should be noted that although the structural features and the isopach features appear similar, the isopach is offset to the northeast and slightly skewed relative to the structures.

At the center of the AOR, Buckeye Brine has drilled three wells. In order that all wells could, in the future, be tied to a reliable and repeatable datum, drilling and openhole wireline measurements utilized a ground level datum. The original surveyor's ground levels have been updated with GPS to account for any differences due to excavation prior to drilling. Baker-Hughes logs were run in all three wells, including:

4. No. 1 Adams - Industry-standard gamma ray-neutron, density, photo-electric, resistivity openhole logs were run from 5900 ft. to the logger's 7305 ft. total depth. A cased hole gamma ray-neutron log was run from 354-5900 ft., and a correlation gamma ray from surface to 354 ft.

5. No. 2 Adams - A gamma ray-neutron, density, photo-electric, resistivity openhole log suite was run from 5930 ft. to the logger's 7007 ft. total depth. A cased hole gamma ray-neutron log was run from 85-5930 ft., and a correlation gamma ray from surface to 85 ft. Advanced acoustic and image logs were acquired in the bottomhole interval.

6. No. 3 Adams - Gamma ray-neutron, density, photo-electric, and resistivity openhole logs were run in the intermediate hole from 838 ft. to the logger's 6035 ft. total depth, and in the bottomhole interval from 6048-7135 ft. Advanced acoustic, image, and nuclear magnetic resonance logs were acquired in the bottomhole section.

Of primary interest is a structural comparison of the No. 1 and No. 3 Adams wells, which shows the No. 1 to be low to the No. 3. It is likewise low to the No. 2 Adams. Formation tops and subsea values are shown in the following table.

	7177 #1 Adams	**Subsea**	**7241 #3 Adams**	**Subsea**	**7178 #2 Adams**	**Subsea**
Datum	763 GL		785 GL		786 GL	
Berea	807	-44	812	-27	821	-35
Big Lime	2372	-1609	2388	-1603	2396	-1610
Packer Shell	3806	-3043	3604	-2819	3620	-2834
Clinton	3660	-2897	3694	-2909	3674	-2888
Queenston	3805	-3042	3821	-3036	3822	-3036
Trenton	5210	-4447	5202	-4417	5212	-4426
Gull River	5860	-5097	5842	-5057	5842	-5056
Lower Chazy?	5910	-5147	5894	-5109	5900	-5114

Wells Creek	absent		5922	*-5137*	5928	*-5142*
Beekmantown	5920	*-5157*	absent		absent	
Rose Run	5982	*-5219*	5960	*-5175*	5970	*-5184*
Copper Ridge	6098	*-5335*	6038	*-5253*	6052	*-5266*
Copper Ridge "B"	6300	*-5537*	6233	*-5448*	6254	*-5468*
Lwr Copper Ridge	6320	*-5557*	6252	*-5467*	6272	*-5486*
Conasauga	6560	*-5797*	6468	*-5683*	6496	*-5710*
Rome	6669	*-5906*	6583	*-5798*	6614	*-5828*
Mt. Simon	7215	*-6452*	7125	*-6340*	NR	-
Precambrian	7295	*-6532*	NR		NR	
Logger TD	7305	*-6542*	7135	*-6350*	7007	*-6221*

Table 2. Formation tops and subsea elevations for the Buckeye Brine No. 1, 2, and 3 Adams wells, Keene Twp., Coshocton Co. All depths during drilling and openhole logging were measured from ground level.

The No. 2 and No. 3 Adams wells, north of the No. 1 Adams, are structurally higher than the No. 1 well (Figure V.B.8.05). At the top of the Mt. Simon, the deepest common horizon in the No. 1 and No. 3 wells, the No. 1 is 112 ft. deeper, this in a surface distance of 921 ft. It is a value out of line with what is thought to be known about the relatively flat strata in the AOR. Wireline depths in all three wells repeat well. Relative ground level elevations are considered reasonable when looking at the land, and have been checked with GPS. The wellbores are considered straight (<3 degrees in the aggregate) through the intermediate holes (i.e., to the production casing points), but no deviation surveys were taken in the bottomhole sections.

The immediate impression from the subsea differences is that a fault is at play. However, a careful comparison of the tops and unit thicknesses from the Berea to the Mt. Simon shows that the most of the units in the No. 1 well are slightly thicker than those in the No. 3 well. The rates of thickening vary, but are typically less than 1.5%. Exceptions, for example, are noted:

- In the No. 1 Adams the lower half of the Conasauga thickens and the upper half thins, such that in the No. 1 well there is a net 5% thinning (Figure V.B.8.06).
- The Lower Copper Ridge in the No.1 Adams thickens slightly through most of the section relative to the No. 3 well, but the thickening is pronounced in the lowermost 40 ft. of the unit (Figure V.B.5.07). Overall the section in the No. 1 Adams is 11% thicker than in the No. 3 Adams. There does not appear to be any repeating of sections in the No. 1 well as if it were normally faulted. Likewise, there are no flags on the No. 3 Adams image log that suggest faulting is present in the wellbore that would be a means of accounting for the short section.

A close examination of the well logs for the Nos. 1, 2, and 3 Adams wells reveals no missing sections in any part of the wellbores as in the case of a normal fault, nor any repeated sections as would be the case for a reverse fault. Image logs show only small scale fracturing, such as is normally attributed as drilling-induced fracturing. There is nothing that resembles a fault zone.

Overall, the evidence is that across the breadth of the Buckeye Brine facility there appears to have been slow subsidence of varying rates over a very prolonged period of time, mimicking the manner of a growth fault as commonly seen in the Gulf of Mexico Salt Dome Province. Growth faults are the vestige of movement that occurs contemporaneously with sedimentation and may leave little or no trace of that movement other than differences in bed thickness across the plane or zone of movement (Figure V.B.8.08). However, the seismic that was run across the Nos. 3 and 1 Adams shows no breakage of the rock in the sedimentary section that overlies the Precambrian basement complex (Figure V.B.8.09), and only a very mild southward dip from the No. 3 well to the No. 1.

As is discussed in Section II.C.5, Interpretation of Seismic Data, the seismic data cannot show any faulting through the sedimentary section between the Buckeye Brine No. 1 and No. 3 Adams wells.

*<u>Appendix V</u> contains map Figure V.A and allied insets which show the location of all known oil and gas wells within the 2-mile radius area of review. Those wells are numerically keyed to the database <u>Table V.A Data For All Wells Within 2 Miles of the Buckeye Brine Facility</u> contained in Appendix V. The map similarly shows all water wells of record, and those are numerically keyed to Table V.D. which is a printed version of the spreadsheet extracted from Ohio DNR online records. Figure V.A also shows:

- Surface bodies of water
- Springs (none identified within AOR)
- Mines (surface and subsurface)
- Quarries
- Other pertinent surface features including residences and roads
- Seismic areas and faults (none known or identified within AOR)
- Boundaries of the facility

References cited:

Mason, G, 1999, Structurally Related Migration of Hydro-carbons in the Central Appalachian Basin of Eastern Ohio, Into the New Millennium: the Changing Face of Exploration in the Knox Play: Sixth Annual Fall Symposium Proceedings, Akron, Ohio, Ohio Geological Society, p. 20-32.

Wickstrom, L. H., Riley, A. R.., Spane, F. A., McDonald, Jas., Sclhucher, E. R., Zody, S. P., Wells, J. G., Howatt, E., 2011, Geologic Assessment of the Ohio Geological Survey No. 1 CO_2 well in Tuscarawas County and Surrounding Vicinity: ODNR, Division of Geological Survey, Columbus, Ohio, 97 p.

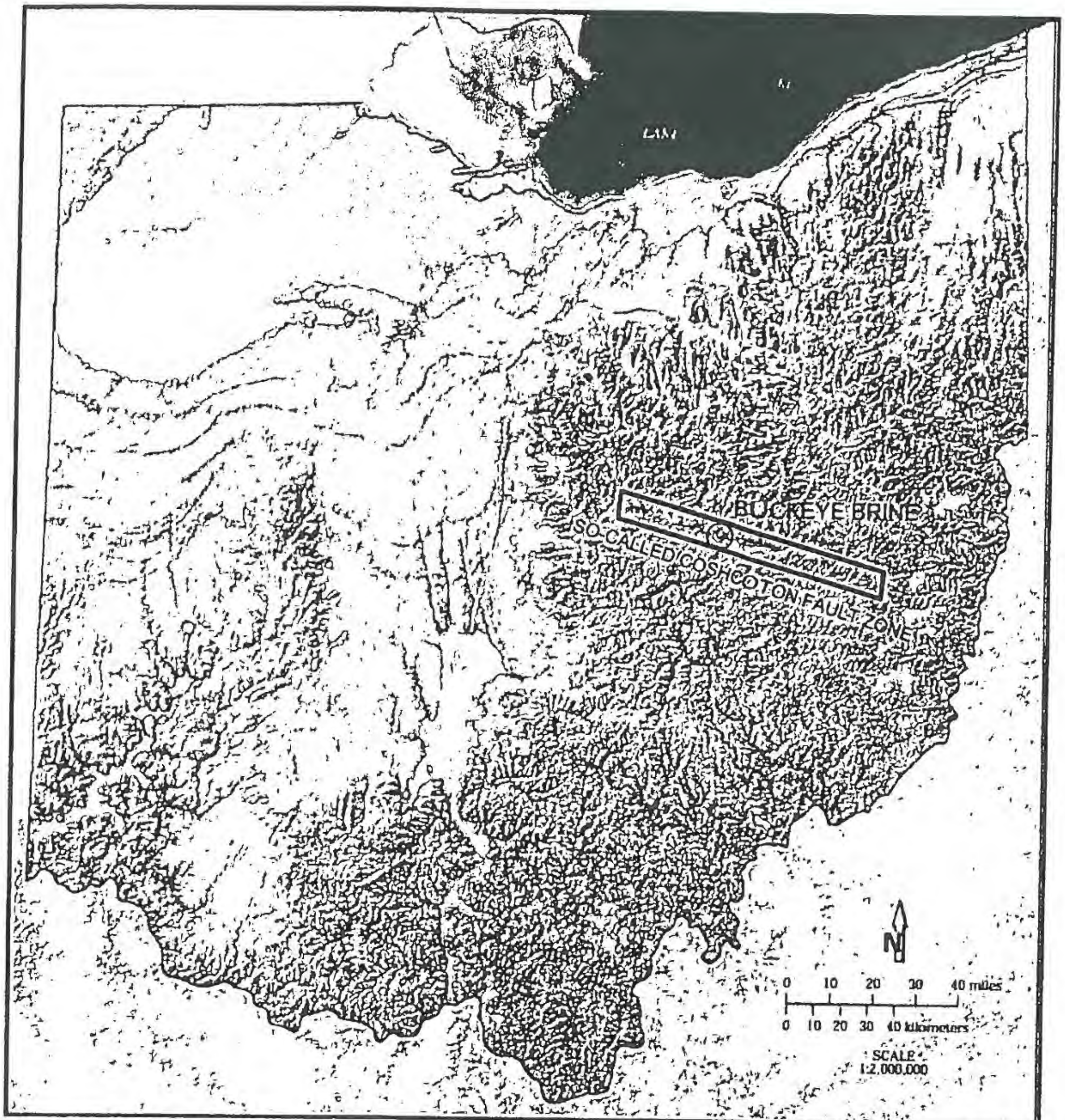


Figure II.B.8.01 Shaded relief map showing the location of the Cambridge Fracture Zone (aka Coshcoton Fault Zone) as defined by surface lineaments

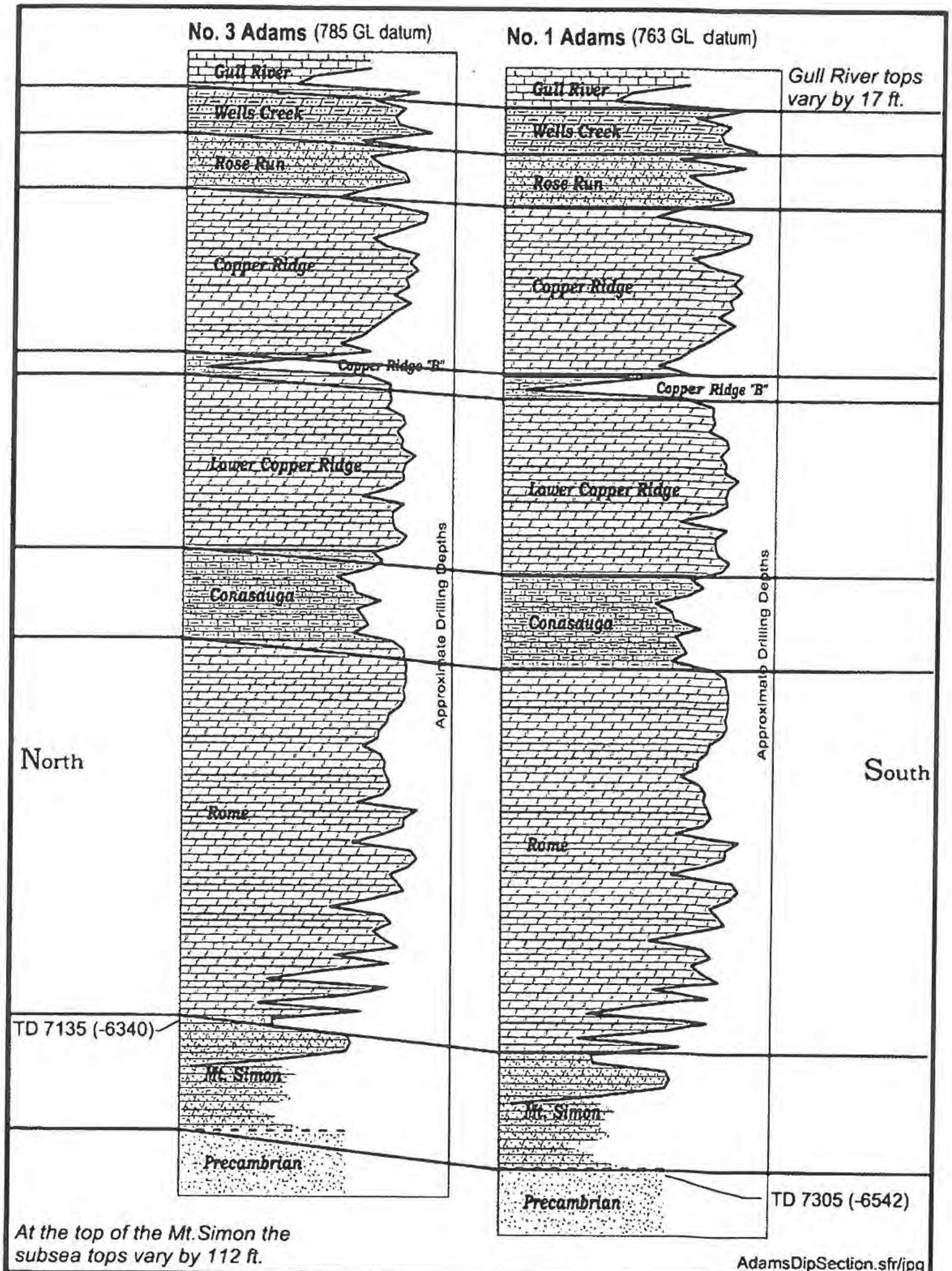


Figure II.B.8.05 - Representational cross section showing structural differences between the No. 3 Adams (left) and No. 1 Adams (right)

Attachment B

II. Seismic Discussion

II.A.5 REGIONAL SEISMIC ACTIVITY

For over 200 years of recorded history Ohio has felt the effects of earthquakes occurring outside it boundaries. In Ohio these events have registered as mild ground tremors to physical damage, as was the case for the 1812 New Madrid, Missouri series of earthquakes that damaged buildings in Cincinnati.

Within Ohio there are certain areas of the State that have historically been shown to be more earthquake prone (Fig. II.A.5.01).

A series of small and larger earthquakes that spanned more than a century in and around Anna, in western Ohio, culminated in a 1937 event that is recorded as having been a 5.4 magnitude (Richter) event. It caused extensive damage that ranged from fixable to ruinous. The most recent event was a 2.6 event recorded in 2008.

Over 100 events have been recorded in northeastern Ohio, most concentrated near the Lake Erie shoreline, with about 25 of those actually occurring in the lake, not far from shore. A 1986 magnitude 5.0 event in Lake Co. was attributed to an injection well that was eventually plugged and abandoned because of the association. However, the frequency of seismic events has continued, underscoring the inherent crustal instability in that area. Most of the earthquakes in the last 30 years have been magnitude 2.0-3.0.

About 30 small (<3.9 Richter) earthquakes are to have taken place in southern Ohio. As a group, these are widely scattered and most predate instrumented recordings.

With the onset of drilling deep Point Pleasant and Marcellus shale wells in eastern Ohio and western Pennsylvania, there have been occasional incidents of induced seismicity in connection with the very high-pressured stimulation treatments used in the wells. Such events may range up to magnitude 4.

Central and east-central Ohio have, for the most part, been without naturally-occurring seismic events.

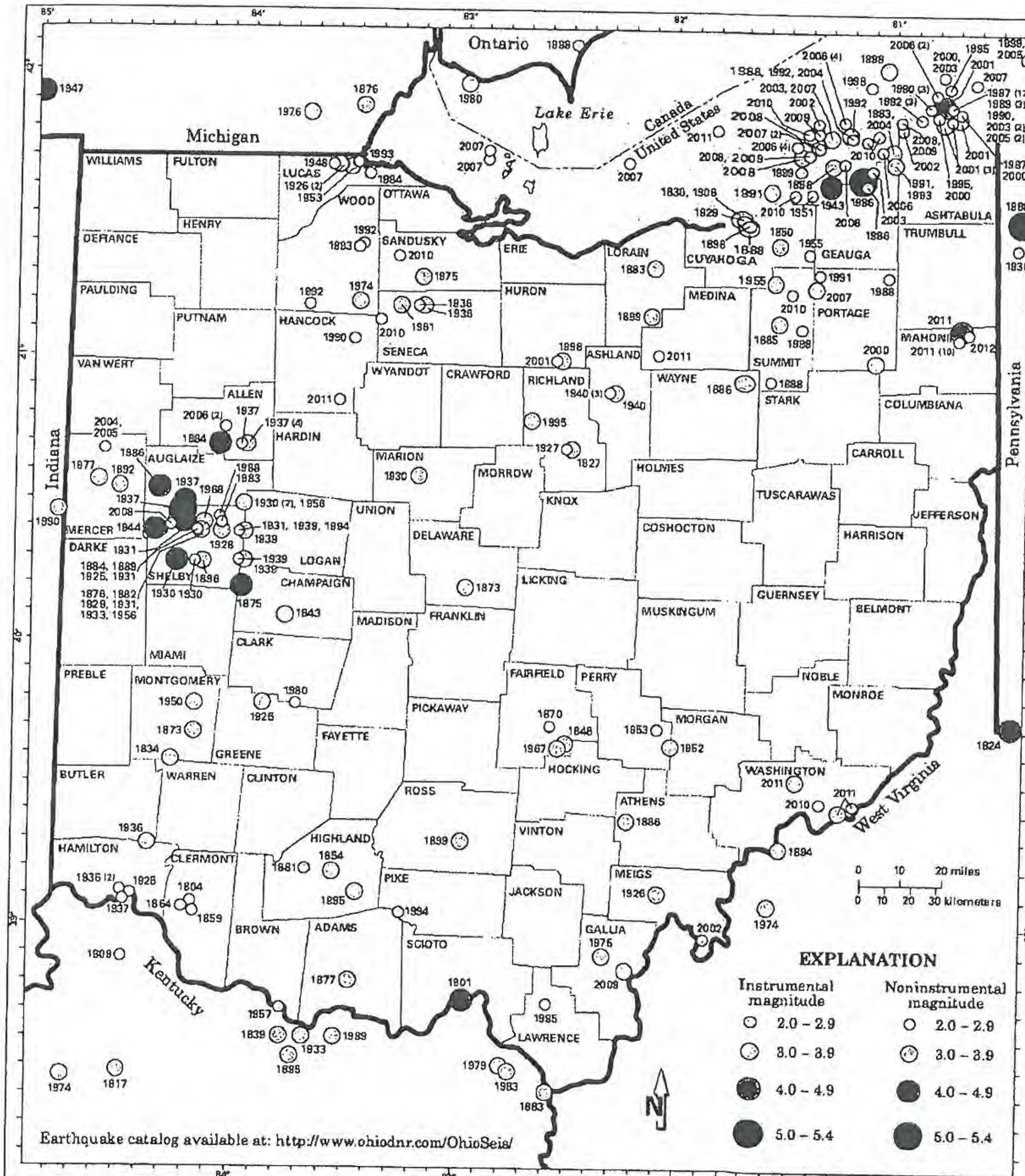


Figure II.A.5.01 - Map showing earthquake epicenters in Ohio and adjacent areas (from Ohio Div. Geological Survey Environmental Series maps BG-2 and OhioSeis Network, 2012)

GROWTH FAULT - This illustration shows two variations on vertical displacement of sedimentary rocks. On the right the displacement happened at once, fracturing all beds at the same time and effecting all beds equally. To the left the displacement has happened continually over a long period. The displacement is most evident in the lower beds; the effect on shallow beds is minimal. The displacement is some combination of fracturing, accommodation by sedimentation, and flexure.

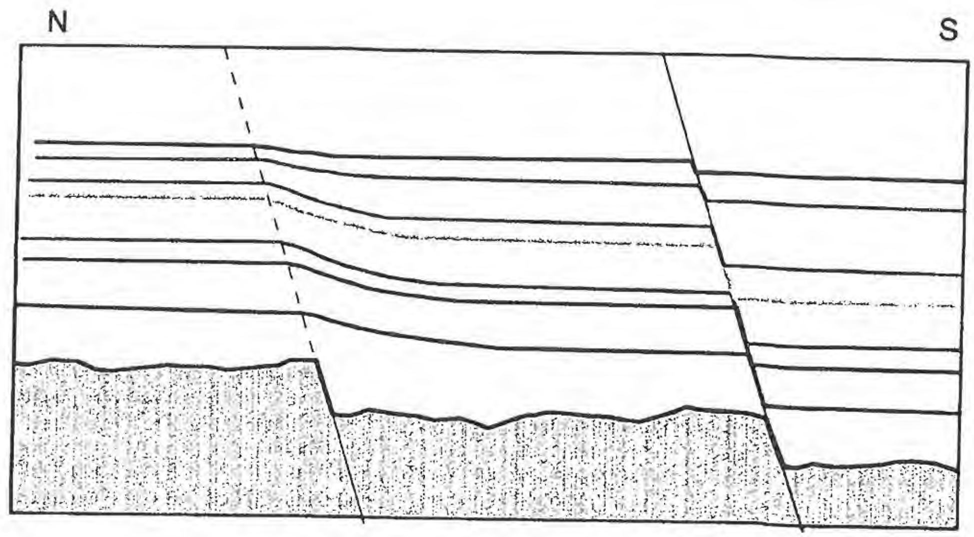


Figure II.B.8.08 – Cross-section illustrating the difference between a late-occurring normal fault (right) and a so-called growth or accommodating fault (left)

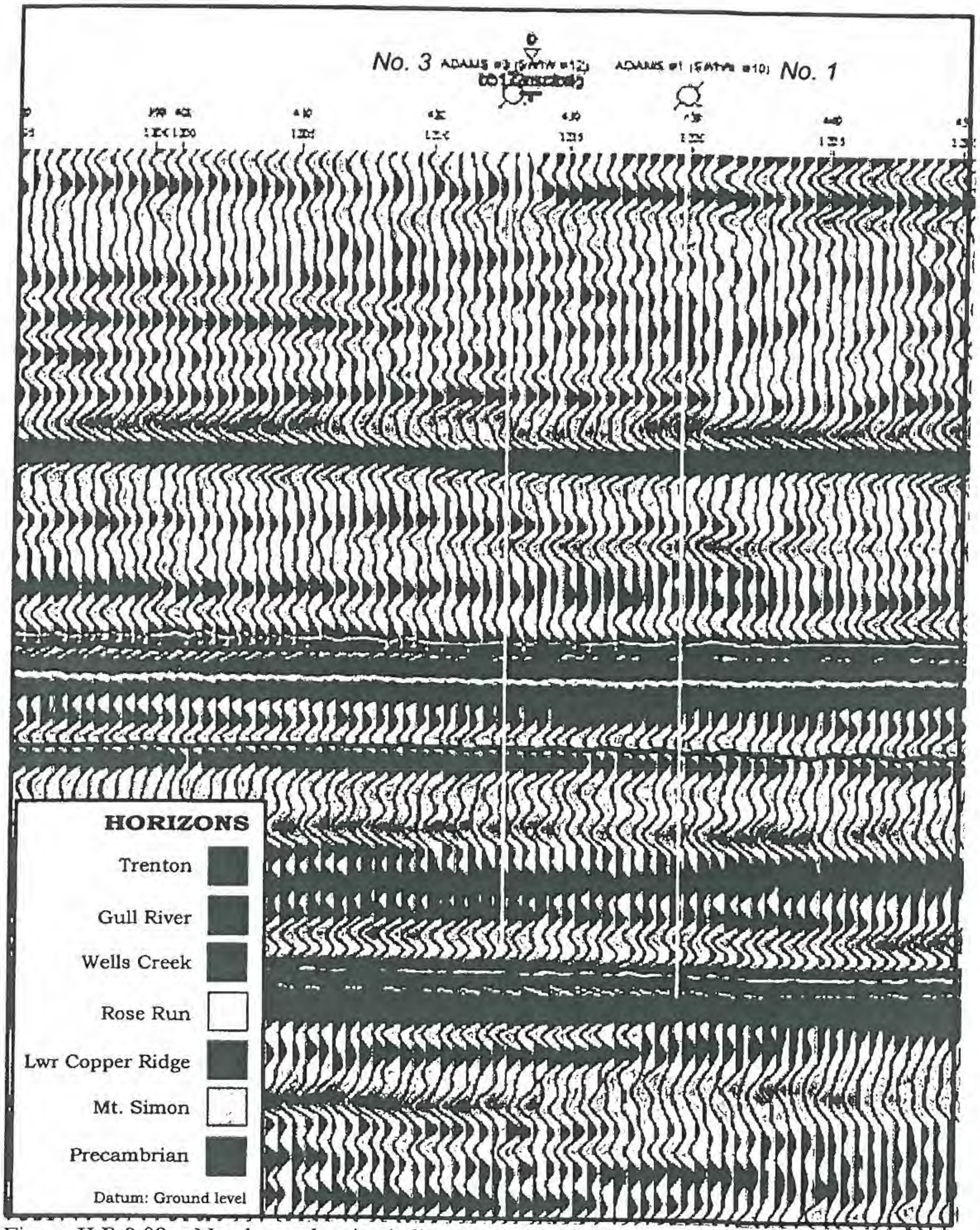


Figure II.B.8.09 – North-south seismic line BB-KTC-16-2D-1 shows an unbroken sedimentary section above the Precambrian, and portrays a slight southward structural dip from the No. 3 Adams to the No. 1 Adams.

II.C SEISMICITY, SEISMIC RECONNAISSANCE AND INTERPRETATION

II.C.1 REGIONAL AND LOCAL SEISMIC MONITORING

Regional seismic monitoring in Ohio is carried out by a number of State and Federal agencies, both scientific and regulatory.

Since 1999 the Ohio Geological Survey, in cooperation with the Ohio Emergency Management Agency, has operated the Ohio Seismic Network, also known as OhioSeis. It is Ohio's oldest wide-ranging seismic monitoring system that currently includes 27 stations deployed primarily at and operated by colleges and universities (Figure II.C.1-01). The Geological Survey coordinates the network and provides data analysis. This Ohio Geological Survey is also part of the U.S. Geological Survey Advance National Seismic System (ANSS) and is a host site for station ACSO.

CODE	LOCATION	LATITUDE	LONGITUDE	ELEV. (M)
ACEO	Jefferson	41.7387	-80.7706	292
ACSO	Alum Creek	40.2321	-82.982	282
BCSO	Carroll	39.7941	-82.5198	258
BGSO	Bowling Green	41.3794	-83.6399	208
BGFO	Huron	41.397	-82.594	185
BHSO	Botkins	40.4696	-84.1763	305
BTCO	St. Clairsville	40.0772	-80.9659	372
CLEO	Cleveland	41.5131	-81.613	205
COWO	Wooster	40.8095	-81.9368	328
CSCO	Springfield	39.8956	-83.7974	323
ECCO	Piqua	40.158	-84.2115	289
GPDO	Montville	41.5831	-81.0717	378
KSTO	New Philadelphia	40.4709	-81.4042	249
KSUO	Kent	41.151	-81.351	346
LCCO2	Kirtland	41.6393	-81.3572	245
LECO	Painesville	41.7175	-81.253	204
MACO	Marietta	39.4166	-81.4491	193
MOSO	Butler	40.6115	-82.3827	370
MUCO	Alliance	40.904	-81.11064	371
OGSO	CLOSED Columbus	40.0568	-82.9654	268
OSLO	Lima	40.7375	-84.0265	285
OSMO	Mansfield	40.797	-82.579	397
OSUO	Columbus	39.9981	-83.0109	226.1
OUAO	Athens	39.3226	-82.0997	194
SSUO	CLOSED Portsmouth	38.7306	-82.9931	162
UOCO	Cincinnati	39.1333	-84.5187	266

CODE	LOCATION	LATITUDE	LONGITUDE	ELEV. (M)
UTLO	CLOSED Toledo	41.6594	-83.618	178
WSCO	Celina	40.5467	-84.5092	270
WSDO	Dayton	39.7826	-84.0633	289
YSUO	Youngstown	41.1043	-80.648	271

The ODNR Division of Oil & Gas Resources Management (DOGRM) operates the OhioNET Seismic Network, which consists of 31 seismic monitoring stations. The stations are located in Counties throughout Ohio with oil and gas operations. They detect micro-seismic events and transmit data in real-time to DOGRM. Once alerted, the data is analyzed to determine if the seismic event is natural or whether there could be a potential relationship with human activities.

CODE	COUNTY	LATITUDE	LONGITUDE	ELEV. (M)
OHN1 (ACSOL)	Mahoning	40.979	-80.6441	377
OHN3	Mahoning	40.9621	-80.6712	325
OHN5	Mahoning	40.949	-80.6648	355
OHM6	Washington	39.3844	-81.3434	261
OHM7	Washington	39.3668	-81.3402	253
OHM8	Washington	39.3681	-81.3693	256
WES1	Washington	39.4303	-81.5112	260
WES2	Washington	39.403	-81.4772	188
OHN9	Washington	39.4091	-81.3669	247
OHU1	Muskingum	39.9545	-81.8216	303
OHH2	Harrison	40.2018	-81.2004	341
OHH3	Harrison	40.248	-81.2679	320
OHH5	Harrison	40.2492	-81.0591	303
OHR1	Meigs	38.9356	-81.7864	188
OHR2	Meigs	38.9725	-81.7891	180
OHT2	Tuscarawas	40.2913	-81.5982	266
OHT5	Tuscarawas	40.4053	-81.3129	267
OHB1	Trumbull	41.2768	-80.8954	278
OHB2	Trumbull	41.4618	-80.7216	315
OHB3	Trumbull	41.2956	-80.6894	335
OHB4	Trumbull	41.2382	-80.6277	353
CES1	Athens	39.1982	-81.7469	239
CES2	Athens	39.2509	-81.7894	221
CES3	Athens	39.2471	-81.7159	204
ORR1	Muskingum	39.9952	-81.8297	251

CODE	COUNTY	LATITUDE	LONGITUDE	ELEV. (M)
ORR2	Muskingum	39.9797	-81.8025	280
ORR3	Muskingum	39.9717	-81.8538	231
CLE1	Guernsey	40.0268	-81.5031	286
CLE2	Guernsey	40.0419	-81.5049	272
CLE4	Guernsey	40.0144	-81.4261	272
HHE1	Pickaway	39.6114	-83.049	222

II.C.2 LOCAL SEISMICITY

The Ohio Division of Geological Survey's OhioSeis catalogs earthquakes in Ohio and has actively monitored for seismic events since 1999. As of 2014 OhioSeis listed no instrumentally recorded natural or induced seismic events greater than magnitude 2.0 within 30 miles of the AOR (Figure II.C.2-01: ODNR Recent Earthquake Epicenters in Ohio Map).

Since 2013 DOGRM has deployed portable seismic stations to monitor for induced seismic events associated with oil and gas well completion operations as well as Class II disposal operations. The Division currently maintains an array of 31 stations. To date, it has not reported any seismic events greater than magnitude 2.0 within a 30-mile radius of the AOR.

Buckeye Brine (Buckeye) installed its own 3-station network around its three Class II wells beginning in September 2013. The processed data from Buckeye's network was delivered to DOGRM for a period of 18 months through February 2016. During that period neither Buckeye's seismic processor nor DOGRM identified any seismic activity attributable to Buckeye's ongoing injection operations. Buckeye has continued to collect and archive data from its network since March 2016.

At the onset of operation of Buckeye's No. 3 Adams Class II injection well (API #34031272410000), DOGRM installed a seismic station on adjacent State owned property for the purpose of providing additional monitoring over and above what was being carried out by Buckeye. For the duration of this monitoring, no induced seismicity attributable to Buckeye's injection wells was recognized by DOGRM.

II.C.3 SEISMIC PLAN

The seismic plan utilized two crossing lines with a total line length of 9.33 miles to effectively cover a 2-mile radius around the Buckeye facility.

The project area was 2 miles north of the city of Coshocton (county seat) and on the near north side of US Rt. 36.

II.C.3.a Line Layout and Coverage

The purpose of the seismic program was to help define the repose of Cambrian and Precambrian strata in the vicinity of the project area. Two intersecting lines were proposed (Figure II.C.3.a-01). The lines were acquired with a combination of dynamite and vibroseis energy sources. All stations on both lines were recorded live for increased fold. Near equal length on both sides resulted in higher stack fold near the center of the lines where the Buckeye Brine facility is located. Cultural factors influenced the line layouts.

A 4.85-mile north-south line designated as BB-KTC-16-2D-1 was run cross-country and crossed the Buckeye facility. It took advantage of utility easements and open fields. There were short skips for pipelines, roads, the airport runway, and power lines.

A 4.48-mile west-east tie line designated as BB-KTC-17-2D-2 was also run cross-country and through the Buckeye facility. There were skips on the north side of Canal Lewisville but vibe points were used to fill in where possible.

II.C.3.b Processing

The seismic processor for this project was Exploration Development, Inc. (EDI), Parker, CO (http://www.exdvpinc.com/). Their primary data processing software is the Mercury International Technology (MIT) iXl package. They also use Green Mountain Geophysical refraction statics software and various support modules written internally. Exploration Development, Inc. (EDI) has been processing seismic throughout Ohio since 1992.

Processing Flow

1. Load Data
2. Geometry Update and Trace Edit
3. Gain Recovery
4. Surface Consistent Deconvolution
5. CDP Sort
6. Zero Phase Spectral Whitening
7. Refraction Statics
8. Velocity Analysis – 2 Passes
9. NMO Corrections
10. Muting – Average NMO Stretch 1.4 to 1
11. Surface Consistent Statics – 2 Passes
12. Trace Balance
13. CDP Trim Statics
14. Dip Moveout , INMO, Vel Analysis, NMO
15. Split Frequency Trim Statics

16. Common Depth Point Stack
17. Trace Balance
18. Migration
19. Noise Subtraction
20. Time Variant Spectral Whitening
21. Further Enhancement (FX Decon / FK)
22. Trace Balance

Additionally, step 14 was replaced by Prestack Time Migration and then finalized as above.

The observer's log in the field files recorded ranges for dynamite shots and vibroseis so that the processor could indicate the various energy sources on the seismic section (Figure 11.C.3.c-01 and Figure II.C.3.c-02). Prints were plotted at 18 traces/inch and 15 inches/second (Figures II.C.3.c-03, II.C.3.c-04, II.C.3.c-05 and II.C.3.c-06).

The No. 1 Adams (API #34031271770000) synthetic was used for correlation. To match the synthetic seismogram to the seismic data, the processor cross correlated the data sets to phase match the seismic to the synthetic. This is the same process used to match the vibroseis data to the dynamite data.

Line Name	BB-KTC-16-2D-1	BB-KTC-17-2D-2
County	Coshocton	Coshocton
Township	Keene/Tuscarawas	Keene/Tuscarawas/White Eyes
Acquisition Date	12/16	2/17
SP	1101-1333	2101-2315
CDPS	202-666	202-630
Miles	4.85	4.48
Receiver Interval	110'	110'
Source Interval	110'	110'
Source	dynamite/vibroseis	dynamite/vibroseis
Sample Rate	1 ms	1 ms
Record Length	4000 ms	4000 ms
Processed Date	12/13/16	2/7/17
Bearing of Line	N to SE	W to E

II.C.4 SEISMIC INTERPRETATION METHODS

The lists below are of all the processed versions provided by EDI that were reviewed for interpretation.

BB-KTC-16-2D-1	BB-KTC-17-2D-2
bb161bx20	bb172bx20orig
bb161es20	bb172es20orig
bb161fk00	bb172fk00orig
bb161fk80	bb172fk80orig
bb161nsnt	bb172nsntorig
bb161ntfx	bb172ntfxorig
bb161raws	bb172rawsorig
bb161tw00	bb172tw00orig
pms161bx20	bb172bx20
pms161fk00	bb172es20
pms161fk80	bb172fk00
pms161nsnt	bb172fk80
pms161ntfx	bb172nsnt
pms161pmst	bb172ntfx
pms161tw00	bb172raws
	bb172tw00
	bb172m80
	bb172m90
	bb172m100
	bb172m110
	bb172m120
	psm172bx20
	psm172fk00
	psm172fk80
	psm172nsnt
	psm72ntfx
	psm172pmst
	psm72tw00

Interpretation was performed in GeoGraphix's SeisVision software and on paper prints of migrated, normal, and reverse polarity data. The No. 1 Adams (API# 34031271770000) synthetic was used for identification and interpretation of key reflectors on BBC-KTC-16-2D-1 and BB-KTC-17-2D-2. Analysis of individual reflectors was performed to enhance details in the seismic waveform and amplitude. Waveforms exhibit different character with different frequencies and with different geology and can confirm formation thickness and geologic sequence. Isochron mapping was compared to known geology.

Detailed wavelet character was interpreted by understanding the relationship of the local geology to the seismic information, regional geology and the frequency content of the seismic data. Time picks from reflection interpretations were then used to construct time-structure maps to show local geological relationships between the wells and for clues to paleotopography.

II.C.5 INTERPRETATION OF DATA

BB-KTC-16-2D-1 and BB-KTC-17-2D-2 were examined for evidence of deformation or faulting in the sedimentary section that could indicate a compromise of the seal in the confining layers. The Cambridge Arch was not observed on the seismic as it is too far east of the line locations and Area of Review (AOR).

Key formation horizons were picked on both lines. These included the Big Lime, Packer Shell, Trenton, Gull River, Beekmantown, Rose Run, Lower Copper Ridge, Mt. Simon, and Precambrian. Various of these horizons were later used to construct stratigraphic sections (arbitrary datums), and structure and isochron maps.

Structure maps were constructed from well control for the top of the Berea sandstone, Big Lime, and Packer Shell for later comparison to the seismic. Although some patterns were noted, it should be said that the control for the mapping was considered fair owing to the suspect nature of the ground level elevations and their effect on calculated subsea elevations. Interpretation of the seismic-generated horizons away from the actual lines themselves can be misleading. In all, the comparisons were considered too tenuous to draw meaningful conclusions. All figures identified in this section of the report are provided in Appendix II.

<u>Figures - BB-KTC-16-2D-1</u>

II.C.5-01 migration 80 Hz, normal polarity, grayscale

II.C.5-02 migration 80 Hz, normal polarity, wiggle trace, color amplitude

II.C.5-03 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Trenton

II.C.5-04 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Gull River

II.C.5-05 migration 80 Hz, normal polarity, wiggle trace, color amplitude, faults

II.C.5-06 migration 80 Hz, normal polarity, color amplitude, faults

II.C.5-07 migration 80 Hz, normal polarity, color amplitude, faults, compressed section

On BB-KTC-16-2D-1, the most evident structure is a basement feature on the north end from SP 1119-1140 that is herein referred to as the "Airport Dome". On the initial Figure II.C.5-5 presentation and subsequent iterations, the feature appears as a pop-up structure, the result of compression that occurred in late Precambrian, with some slow accommodation of stress that impacted lower and middle Cambrian sedimentation. The faults are not seen to extend above the base of the Precambrian.

Across the central and southern portions, line BB-KTC-16-2D-1 exhibits minor undulations, without any definable basement influence. The seismic failed to reveal faulting or vertical discontinuity between the Adams wells.

Figures - Line BB-KTC-17-2D-2

II.C.5-08 migration 80 Hz, normal polarity, grayscale

II.C.5-09 migration 80 Hz, normal polarity, wiggle trace, color amplitude

II.C.5-10 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Trenton

II.C.5-11 migration 80 Hz, normal polarity, wiggle trace, color amplitude, flattened Gull River

The data quality for line BB-KTC-17-2D-2 was considered fair to good in comparison to line BB-KTC-16-2D-1. It was acquired primarily through the Tuscarawas River valley where, as previously noted in Section II.C.3d, the weathered zone consisted for the most part of up to 175 ft. of unconsolidated sand and gravel valley fill. A back-filled portion of the Erie Canal and its feeder ponds are thought to have been especially detrimental to those portions of the line that are included in the intervals from SP 2101-2150 and SP 2230-2270.

The Precambrian surface shows some undulation that is considered to be within the range of normal. The most notable feature is on the west end of the line where there appears a down-to-the-west flexure contained in the interval SP 2165-2170 (Figure II.C.5-14), after which the PC surface gradually regains its previous time elevation by the west end of the line.

The Cambrian and Ordovician sedimentary section is either flat or, on the west end of the line, subtly mimics the underlying Precambrian topography (Figure II.C.5-12). None of the units appear faulted so as to compromise the sealing capability of the designated confining layer.

There is some fabric to the Precambrian section. This may change in appearance from presentation to presentation, enough so that it cannot be determined if the fabric is due to structure (folding and/or faulting), or changes in the rock character.

The data was used to construct time structure maps for the Trenton, Gull River, and Precambrian. Isochron maps were made for the Trenton-Precambrian and Gull River-Precambrian intervals.

Figures - Time Structure and Isochron Maps

II.C.5-12 Trenton Horizon, Time Structure Map

II.C.5-13 Gull River Horizon, Time Structure Map

II.C.5-14 Precambrian Horizon, Time Structure Map

II.C.5-15 Trenton - Precambrian Horizons, Isochron Map

II.C.5-16 Gull River - Precambrian Horizons, Isochron Map

Attachment C

Well Construction

III. INJECTION WELL CONSTRUCTION AND OPERATION

III.A. Construction and Completion Summary for Adams # 3

This UIC permit application is being prepared and submitted to authorize the conversion of a Class II waste disposal well known as the Adams #3 into a well that can receive Class I non-hazardous waste. The Adams #3 well is located within a facility constructed and operated by Buckeye Brine, LLC in Coshocton, Ohio. The Adams #3 well was spudded on 8/25/2014 and completed on 9/16/2014.

III.A.1. Well Schematic for Adams # 3

The current configuration of the Adams #3 well is depicted on Figure III.A. The schematic shows borehole sizes, tubular sizes, depths, specification and cementing information.

III.A.2. Adams #3 Total Depth

The Adams #3 well was drilled to a total depth of 7,135 feet below ground level. During routine mechanical integrity testing performed in October of 2016, wireline tools encountered resistance at a depth of 7,065 feet. The obstruction is most likely fill and does not impair the ability to perform RTS, falloff, and other diagnostic testing.

III. A.3. Well Casing and Tubing Strings

The Adams #3 well was designed to exceed the current requirements for Class I injection wells and is constructed with conductor casing, surface casing, longstring casing and injection tubing, consisting of steel casing and tubing. Different factors have been incorporated into the proposed casing and tubing program including:

- Hole sizes;
- Injection zone and injection interval depths;
- Depth of lowermost underground source of drinking water (USDW);
- Injected waste and formation fluid composition, corrosiveness and compatibilities;
- Injection rates and operating pressures (annular and wellhead);
- Casing and tubing sizes, weights, grades and mechanical strength properties; and
- Types and grades of cement.

III.A.3.a. Casing and Injection Tubing- Type, Weight, Grade, Wall Thickness, End Finish, Set Depth, and Life Expectancy

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing, and injection tubing.

Conductor Pipe

Size (OD)	16 inches
Internal Diameter	15.376 inches (15.188" drift ID)
Weight	55 lb./ft.
Grade	A-53 Grade B
End Finish	Welded
Setting Depth	42 feet
Life Expectancy	>30 years (life of well)

Surface Casing

Size (OD)	11.75 inch OD
Internal Diameter	11.084 (10.928" drift ID)
Weight	42 lb./ft.
Grade	H40
Coupling Size	11.75 inches
Thread	ST & C
Setting Depth	842 feet (512 ft. below lowermost USDW)
Life Expectancy	>30 years (life of the well)

Longstring Casing

Size (OD)	8 5/8" inch OD
Weight	32 lb./ft.
Grade	HCK
Thread	ST & C
	Setting Depth 5,950 feet – Caliper log performed 10/19/2016 discovered bottom two sections separated below the packer with new contiguous length to 5,912 ft. BGL
Life Expectancy	>30 years (life of the well)

Injection Tubing

Size (OD)	4.5
Internal Diameter	4.052 inches (3.927" drift ID)
Weight	10.5 lbs./ft.
Grade	J-55
Setting Depth	5,916

Note: The top of the packer is set at 5,902' BGL. The external and internal forces on the injection tubing and longstring casing are not active below this depth. For tensile strength comparisons on the injection tubing and longstring casing, the full installed length is used

III.A.3.b. Tubulars- Collapse Resistance, Internal Yield Pressure, Joint Strength, Yield Strength

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing and injection tubing.

Conductor Pipe (16", 55 lb./ft., A53 Grade B)

Collapse	290 psi
Burst (internal yield)	850 psi
Joint Strength	258,000 lbs.
Yield Strength	384,000 lbs.

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Surface Casing (11.75", 42 lb./ft., H40 ST&C)

Collapse	1,070 psi
Burst (internal yield)	1,980 psi
Joint Strength	307,000 lbs.
Yield Strength	478,000 lbs.

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Longstring Casing (8 5/8", 32 lb./ft., HCK, ST&C)

Collapse	4,130 psi
Burst (internal yield)	3,930 psi
Joint Strength	497,000 lbs.
Yield Strength	503,000 lbs.

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Injection Tubing (4.5", 10.5 lb./ft., J-55)

Collapse	4,010 psi
Burst (internal yield)	4,790 psi
Joint Strength	132,000 lbs.
Yield Strength	165,000 lbs.

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

III.A.3.c. Casings and Injection Tubing- Maximum External and Internal Pressures and Axial Loading Conditions during Construction, Operation, and Closure

The casing and tubing strings will be subject to different stresses during the different phases of construction, operation, and closure. An analysis is presented below to determine the maximum stresses during any of these phases. For any other condition, the stresses on the component will be less. The assumptions made here maximize the calculated stress on the component and will represent the maximum during construction, operation, and closure procedures.

External Pressures - Casings

For the maximum external pressure, it is conservatively assumed that somehow the inside of the casing in question has become entirely evacuated from surface to its total depth with only atmospheric pressure on the inside, and that a maximum formation hydrostatic pressure (assuming a 10 lb./gal equivalent mud weight) is exerted against the external surface of the casing. This condition is assumed to occur during the casing installation phase, but could also occur during jet-back cleanout operations and during closure. In any event, these conditions are very unlikely to occur, but are nonetheless presented here to provide a conservative outcome.

Design Formation Pressure

For the purposes of the casing and tubing design, the formation pressure gradient is assumed to be 0.52 psi/ft. or a 10 lb./gal equivalent fluid density. See a justification for this pressure immediately below.

Measured Ambient Formation Pressure from Existing Wells

Ambient pressure measurements have been obtained from all three wells during annual MIT testing. On October 19, 2016, the static BHP in the Adams #3 was measured to 3,331 psig at a depth of 7,000 ft. BGL. The measured BHP divided by the depth indicates that the formation pressure gradient was 0.476 psi/ft. (3,331/7,000). For comparison, the gradient in the Adams #1 well was calculated to be 0.474 psi/ft. based on a static BHP measured in that well on October 18, 2016. For a conservative evaluation, we assumed that the ambient formation pressure gradient of 0.52 psi/ft. (10 lb./gal equivalent density). The resulting equation is:

$$\mathbf{P_{ext} = 10\ lb./gal*0.052\ psi/ft.\ /\ lb./gal*\ Casing\ Depth}$$
$$\mathbf{= 0.52\ psi/ft.\ *\ Casing\ Depth\ (ft.)} \quad \ldots \text{(i)}$$

External Max Press$_{conductor}$ = 0.52 psi/ft. * 42 ft. **= 21.84 psig**

External Max Press$_{surface}$ = 0.52 psi/ft. * 842 ft.

$= 438$ psig

External Max Press$_{longstring}$ = 0.52 psi/ft. *5,912 ft.
= 3,074 psig

Internal Pressures - Casings

For the maximum internal pressure, it is conservatively assumed that somehow the outside of the casing has become entirely evacuated from surface to its total depth with only atmospheric pressure on the outside, and that a 10 lb./gal equivalent mud weight is exerted against the internal surface of the casing. The resulting equation is given by (same as previous):

P_{int} = 10 lb./gal*0.052 psi/ft. / lb./gal* Depth of Casing

= 0.52 psi/ft. * Depth of casing (ft.) ... (ii)

Internal Max Press$_{conductor}$ = 0.52 psi/ft. * 42 ft.
=21.84 psig

Internal Max Press$_{surface}$ = 0.52 psi/ft. * 842 ft.
= 438 psig

Internal Max Press$_{longstring}$ = 0.52 psi/ft. *5912 ft.
= 3,074 psig

Axial Loading - Casings

For the maximum load, it is conservatively assumed that the casing is "hanging in air" with no buoyant force exerted by the circulating fluid or surrounding formation in the borehole. This unrealistic condition could only be realized if the borehole somehow became fully evacuated of fluids, and had no circumferential contact with the walls of the borehole. Nevertheless, it is used here for a worst possible case condition. The resulting equation is given by:

Max Tension Load = Weight of Casing (lb./ft.) * Depth of Casing (ft.) ... (iii)

MaxTensionLoad$_{conductor}$ = 55 lb./ft. * 42 ft. =
2,310 lbs.

MaxTensionLoad$_{surface}$	**= 42 lb./ft. * 842 ft.**
	= 35,364 lbs.

<u>8 5/8", 32 lb./ft., HCK</u>	**MaxTensionLoad$_{longstring}$ = 32 lb./ft. *5,912 ft.**
	= 189,184 lbs.

<u>External Pressures - Injection Tubing</u>

For the maximum external pressure, it is conservatively assumed that maximum external pressure is equal to the maximum allowable surface injection pressure plus an additional 100 psi. For the Adams #3 this pressure would be 1,462 psig (MASIP = 1,362 psig) + 100 psig additional differential pressure). This represents the maximum possible condition during annulus pressure testing at Buckeye Brine. During injection operations, the well is operated with much less differential pressure. Additionally, it is assumed that the annulus fluid is a base solution in 10 lb./gal the maximum annulus fluid density, although it may actually be something less. Finally, it is assumed that there is no injection pressure (no injection), and that the tubing fluids are in equilibrium with the injection interval. At Buckeye Brine, the minimum static injection interval pressure in the Adams #3 is 3,331 psig at 7,000 feet, corresponding to a hydrostatic gradient of 0.476 psi/ft. Therefore, to calculate the maximum external (differential pressure at the bottom joint of injection tubing):

External MaxPress$_{inj.tubing}$ = 10 lb./gal*0.52 psi/ft. / lb./gal* Depth of injection tubing (ft.) + 1,462 psig – 0.476 psi/ft.* injection tubing depth ...(iv)

With the known proposed values:

External MaxPress$_{inj.tubing}$ =0.52 psi/ft.*5,912- feet +1,462 psig – 0.476 *5,912 feet

Max External Press$_{inj.tubing}$ = 1,722 psig

Internal Pressures - Injection Tubing

For the maximum internal pressure exerted on the injection tubing, it is assumed that 10 lb./gal fluid is being injected into the well at the maximum allowable injection pressure (1,362 psig), and that the annulus is filled with fresh water. A column of water, in this case the annulus, exerts a downward and outward force of 0.433 psig/ft. With a column of fresh water inside the annulus and with no external pressure added at the surface, the pressure at the lowest point in the tubing above the packer would be 5,902 ft. X 0.433 psig/ft. or 2,556 psig at 5902 ft. The resulting equation which incorporates the weight of water in the annulus is given by:

$\text{InternalMaxPress}_{\text{inj.tubing}}$= 0.52 psi/ft. * tubing depth (ft.) +1,362 psig - 0.433 psi/ft.* depth of injection tubing ...(v)

Internal $\text{MaxPress}_{\text{inj.tubing}}$ = [(0.52 psi/ft.*5,902 ft.) +1,362 psig]- [0.433 psi x 5,902 ft.]

Max Internal $\text{Press}_{\text{inj. tubing}}$ = 1,875 psig

Axial Loading - Injection Tubing

For the maximum tensile load, it is conservatively assumed that the injection tubing is latched into the packer with no buoyant force exerted by the annular fluid or fluid inside the injection tubing, and that there is no additional tensional loading pulled on the injection tubing (normally 10,000 – 15,000 lbs. of slackoff weight is stacked onto the packer). Finally, it is assumed that the injection string is cooled by 50° F, relative to the ambient temperature at which it was landed. The resulting equation is given by:

Max Load = Tubing Wt (lb./ft.) *Tubing Depth (ft.) + thermal contraction (lbs.)

...(vi)

Calculate thermal contraction load from temperature change for 50° F cooling:

Thermal Tension (lbs.) = 207* As * ΔT ...(vii)

(source: Baker Oil Tools Technical Handbook, 1995)

Where;

As = cross-sectional area of tubing = $(4.50^2 - 4.05^{2)} * \pi/4 = 3.022\ in^2)$

ΔT = temperature change (cooling in this case) = 50° F

207 = units conversion factor

$= 207 * 3.022\ in^2 * 50°F$

$= 31{,}278$ lbs.

Finally, from equation (vii) above:

Max Tensile Load$_{\text{injection tubing}}$ = 10.5 lbs./ft. * 5,910 ft. + 31,278 lbs.

= 93,333 lbs.

III.A.3.d. Detailed Factor of Safety Calculations for Each Tubular String

Given the strength of the materials that comprise the proposed well casings and injection tubing, along with the calculated maximum expected (although virtually impossible to actually occur), conditions calculated in equations (i) through (vii) above, the safety factors can be determined for each component through the equation:

SF = 1 + (Material Strength – Max. Calculated Stress) / Max calculated Stress (viii)

The casing strings (conductor, surface and longstring) will be considered in I) through III) below and then the injection tubing will be considered.

I) Safety Factor for External Collapse Strength for Casings

Conductor Pipe (16", 55 lb./ft., A53)

$SF_{conductor} = 1 + (290\ psi - 21.8\ psi) / 21.8\ psi$

$SF_{conductor}$ =13.30

Surface Casing (11.75", 42 lb./ft., H40 ST&C)

$SF_{surf\ casing} = 1 + (1{,}070\ psi - 438\ psi)\ /438\ psi$

$SF_{surf\ casing} = 2.44$

Longstring Casing (8 5/8" 32 lb./ft., HCK)

$SF_{longstring\ csaing} = 1 + (3{,}930\ psi - 3{,}069\ psi)\ /\ 3{,}069\ psi$

$SF_{longstring\ casing} = 1.28$

II) Safety Factor for Internal Yield Strength for Casings

Conductor Pipe (16", 55 lb./ft., A53)

$SF_{conductor} = 1 + (850\ psi - 21.8\ psi)\ /\ 21.8\ psi$

$SF_{conductor} = 39.0$

Surface Casing (11.75", 42.0 lb./ft., H40 ST&C)

$SF_{surf\ casing} = 1 + (1{,}980\ psi - 438\ psi)\ /\ 438\ psi$

$SF_{surf\ casing} = 4.52$

Longstring Casing (8 5/8" 32 lb./ft., HCK, use joint strength)

$SF_{longstring\ csaing} = 1 + (497{,}000\ psi - 189{,}184\ psi)\ /\ 189{,}184\ psi$

$SF_{longstring\ casing}$ **= 2.63**

III) Safety Factor for Tensile Strength for Casings (use lessor of joint strength or yield strength, as appropriate)

Conductor Pipe (16", 55 lb./ft., A53)

$SF_{conductor} = 1 + (258{,}000\ lbs. - 2{,}310\ lbs.)\ /\ 2{,}310.lbs.$

$Co_{nductor}$ **= 111.7**

Surface Casing (11.75", 42 lb./ft., H-40 ST&C, use joint strength)

$SF_{surf\ casing} = 1 + (307{,}000\text{ lbs.} - 35{,}364\text{ lbs.})\ /35{,}364\text{ lbs.}$

$\mathbf{SF_{surf\ casing} = 8.68}$

IV) Safety Factor for External Collapse Strength for Injection Tubing

$SF = 1 + (4{,}010\text{ psi} - 1{,}728\text{ psi})\ /1{,}728\text{ psi}$

$\mathbf{SF_{inj\ tubing} = 2.32}$

V) Safety Factor for Internal Yield Strength for Injection Tubing

$SF_{inj.tubing} = 1 + (4{,}790\text{ psi} - 1{,}875\text{ psi})\ /\ 1{,}875\text{ psi}$

$\mathbf{SF_{inj.tubing} = 2.56}$

III) Safety Factor for Tensile Strength for Injection Tubing

Includes load for weight and thermal contraction, as discussed in Section III.A.3.c above, for Maximum Injection Tubing Stress:

$SF_{inj.tubing} = 1 + (132{,}000\text{ lbs.} - 93{,}333\text{ lbs.})\ /\ 93{,}333\text{ lbs.}$

$\mathbf{SF_{inj.tubing} = 1.41}$

In summary, the sizes, weights, grades, coupling systems, and materials of construction for the proposed new well casings and injection tubing are more than adequate for use in the proposed new well at the Buckeye Brine facility, even when considering maximum calculated conditions that greatly exceed what is expected, or that is even possible in most cases.

III.A.3.e. Injection Packer Specifications- Size, Type, Life Expectancy, and Setting Depth

The packer is a 4.5-inch x 8 5/8-inch ASI-X set, with the top of the unit at 5,902 feet BGL. The specification sheet for the packer is attached as Figure III.B at the end of this section.

III.A.3.f. Selection of Tubulars

The well design includes tubular selected based on strengths, grade, and depths related to:

- Depths of lowermost USDW, injection interval, and zone;
- Volumes of wastes to be injected;
- Pressures under static and injection conditions;
- Fluid properties (density, composition, corrosive properties, temperature) of injection and formation fluids; and
- Subsurface conditions (pressures, temperatures).

As discussed above in the detailed calculations regarding strengths of the various casings and tubular components (Section III.A.3.d), the well components are of sufficient strength to withstand a reasonable potential stress projection with substantial multiples of design capability.

Lowermost USDW Protection

The lowermost USDW, defined to be 330 feet below ground surface (Section II) is covered by two separate casing strings (surface casing and longstring casing), with each string extending through and below the USDW. Copies of the Casing Record form which document that an ODNR representative witnessed the cementing of the surface and longstring casings. Copies of the "Cement Tickets" provided by the cementing company also indicate returns to surface during cementing of the conductor, surface, and longstring casings. A cement bond log was performed on September 11, 2014. The log, performed by Wildcat Wireline indicated that there was little or no cement behind the longstring casing. As the log results were not consistent with the cement returns to surface during the cementing of the longstring, ODNR agreed that a second bond log should be performed. On September 12, 2014, the ODNR representative assigned to the Adams #3, witnessed a second bond log performed by Appalacian Wireline.

The second bond log confirmed what the ODNR had witnessed during the cementing stage. The ODNR approved the completion and use of the Adams #3 well, based on the cement observed as returns at the surface and the bond log performed by Appalachian. A copy of both logs is provided at the end of Section 2.

The selection of the tubular and design calculations and factor of safety calculations given above considered current and maximum possible formation densities, injection pressures, and formation pressures (both maximum and minimum in the case of complete evacuation of the borehole due to loss of circulation).

Reservoir and Injected Fluid Temperature and Pressure Considerations

As discussed in Section IV (Reservoir Mechanics) the static bottom-hole temperature at TD was measured at 145° F before injection began in the well. Logs run during subsequent annual mechanical integrity tests indicate that the maximum temperature observed at 7,000 ft. BGL is approximately 133°F. During mechanical integrity testing performed on October 19, 2016, the static reservoir pressure at 7,000 ft. BGL was measured to be 3,331 psig. Coupling the pressure increase at the maximum allowable permitted injection pressure (1,362 psig) with a maximum permitted injection fluid specific gravity of 1.2 would result in a maximum bottom-hole reservoir pressure of 4,693 psig:

> Measured BHP at depth 7,000 ft. + surface pressure at MASIP =max bottom hole pressure
> 3,331 + 1,362 = 4,693 psig.

While there are no industry standards that define High Pressure High Temperature (HPHT) reservoir conditions, Schlumberger suggests that HPHT conditions begin above 300° F and 10,000 psig. These conditions are not present at Buckeye Brine, as described in the pressure discussion above and in Section IV. Furthermore, the design calculations and factor of safety calculations presented in Section III. A3.c-d demonstrate that the selected tubular are more than sufficient to meet the expected maximum possible adverse conditions at Buckeye Brine.

III.A.4. Type of Completion and Completion Interval

The type of completion used for the Adams #3 is an open-hole that begins at the bottom of the longstring casing (5,912 ft. BGL) and extends to 7,135 ft. BGL. A schematic of the well construction and configuration is provided as Figure III.A.

III.A.5. Centralization Program

A float shoe and float collar were run on the longstring casing to facilitate adequate cementing and cement bonding. A bottom joint float collar was installed 10 ft. from the bottom of the casing and centralizers were installed on the first 10 joints run into the well.

III.A.6. Proposed Annulus (Packer) Fluid

The proposed packer fluid will consist of freshwater with a commercial corrosion inhibitor and oxygen scavenger added at concentrations recommended by the supplier of the additives. The annulus fluid management system includes a 300 gallon poly tank for storage of the treated freshwater.

III.A.7. Drilling and Completion Procedure

The driller's daily log for the Adams #3 indicates that the well was spudded on August 25, 2014. The contents of the driller's daily log are provided as Table III.A.

Table III.A. Daily Driller Log

Buckeye Brine,LLC.
Adams #3
SWIW #12 — *DAILY DRILLING REPORT*

Date	
8/19/2014	Build Location
8/20/2014	Build Location & Stone
8/22/2014	Start Rig Move In
8/23/2014	Finish Rig move ; Rig Up ; Shut Down
8/25/2014	Should Spud Conductor hole late AM
8/26/2014	7:00 AM WOC; Drill 17 1/2" HOLE TO 62'; Set 44' of 16" Conductor Cement to surface ; Good Returns; Plug Down 10:30 PM; This AM constructing Close Loop Drilling System
8/27/2014	7:00 AM -125' ;Drilling on Fresh Water ; Start drilling at 5:30 AM
8/28/2014	7:00 Am -Tripping out- Drill 14" hole to 877'on fresh water TD Surface Hole At 4:45 AM ;Will set 842' of 11 3/4"& Cement to surface
8/29/2014	6:00 AM ;Drilling on Fluid 1172' ; BOP test witness by ODNR ; Resume drilling at 2:05 AM ; Run 842'- 11 3/4" 47# Casing; Universal cement with 412 sxs; 8 Bbls of returns ;Job witnessed by A. Adgate & M.Brown
8/30/2014	6:30 AM; 2512'; Drilling on fluid; 1Hr/Kelly; Top of Lime 2398'
8/31/2014	8:00 AM; 2812'; Drilling on fluid; 1 1/2 Hr/Kelly;Trip out 10 5/8" PDC bit

	Trip in 10 5/8" Tricone Bit; Clean mud tanks.
9/1/2014	6:30 AM; 3289'; Drilling on fluid; 1 1/2 Hr/Kelly.
9/2/2014	7:30 Am - 3722'; Drilling on Fluid ; Expect to trip back to PDC at 3750'
9/3/2014	8:00 Am- 4180' :Drilling on Fluid ; Trip Tricone at 3925' ; Ran in 10 5/8" PDC ; Resume drilling at 1:15 AM : Drill Rate 1/2 Hr./Kelly; Drilling Queenston Shale
9/4/2014	7:00 AM - 5220' ; Drilling on Fluid ; Will trip out PDC and run in Tricone at 5337' Kelly down; StratiGraph on site; Start trip at 8:30 AM Back on Bottom with Tricone at 4:30 PM
9/5/2014	8:00 Am ; 5470' Drilling on fluid; 1Hr. 45 Mins./Kelly
9/6/2014	8:00AM - 5845' ; Drillrate 1 1/2 Hr./Kelly; will drill to 6060' for longstring See attached Mudlog .
9/7/2014	8:00 am - Logging; drill to 6056'; circulate hole ; Standback drill pipe See attached Mudlogs .
9/8/2014	8:00 AM; Circulating out fillup; ran 8 5/8" to 6017.5'; complete immediate open hole logging; 9:15 AM start longstring cement.
9/9/2014	8:00 AM - WOC ; Universal Cemented Stage 1 with total volume 835 Sxs. 210 Sxs. Unifill +10% Salt;1/4#/Sx Flake ;Yield 1.82 & 625 Sxs.\ Class A 5% Salt ; 75% CFL-117 ; 5% CR-3 ; 1/4#/sx Flake Yield 1.20 Drop Dart,open 2 stage tool ; Circulate out 31 Bbls. of cement ; Circulate for 5 hrs. ; Start Stage 2 at 4:00 PM ; Cement with 382 Sxs./Unifill Light + 10% Salt ; Yield 1.82 ; Land plug @2150# 37 Bbls. Of returns ; Shutdown ; Will Bond Log Wed. @ 6:00PM
9/10/2014	8:00AM -Drilling out 2 Stage Tool; Start tripping in at 2:00 AM
9/11/2014	8:00 AM - StandBy; Run RadialCement Bond Log eith Wildcat Wireline Services ;Log showed No Cement from 0' to 272' ; No Cement from 5988' to 5860' ; Considering 2 nd opinion with Baker-Hughes
9/12/2014	8:00 AM 6119' ; Drilling on Fluid ; Run 2nd Bond Log with Appalachian Wireline: Cement from TD to Surface; ODNR Approval to proceed; Start trip in with 7 7/8" Tricone at 6:15 PM
9/13/2014	8:00 AM; 6649'; Drilling 1 1/2 Hr/Kelly
9/14/2014	7:00 AM, 7035' 9:00 AM; 7070'; Drilling 1 1/2 Hr/Kelly 1:15 PM; TD hole at 7150'
9/15/2014	8:00Am ; Baker logging 7 7/8"open hole ; Logging operation required 20 Hrs. ; Nipple Down Bop ; Nipple up ; Run 4 1/2" J-55 -10.5 # with Arrow Set 8 5/8" X 4 1/2" Packer ; Set at 5926' ; Pump 248 Bbls. Water with Inhibitor in Annulus ; Pressured backside to 1500#; Held for 15mins ; No pressure fall off; Witness by D. Ball ODNR; Test completed at 6:15 Am ; It's a good one
9/16/2014	7:00 AM Rigging Down

III.A.8. Cementing Program

The cementing program for the conductor, surface, and longstring casing was to circulate sufficient cement to see returns at the surface. Returns were observed by ODNR staff during the cementing of the surface and longstring casings (see ODNR completion records, casing ticket and permit forms in Appendix III).

A cement bond log (copy provided in Technical Report Appendix III) indicates that well-bonded cement is present behind the long string casing from 5912 ft. BGL to the surface. A copy of the ODNR Casing Inspection Ticket, which contains information about the type and amount of cement that ODNR staff witnessed being used behind each size of casing installed, is provided as Attachment III.B.6.

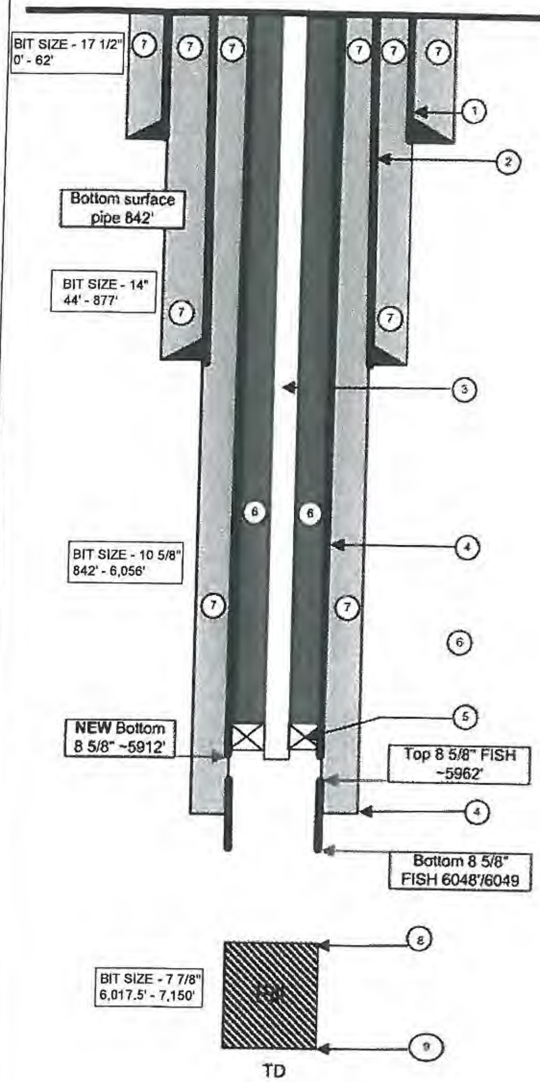
III.A.9. Collection of cores and formation fluids

No cores or samples of native formation fluids were collected during the drilling and completion of Adams #3. Buckeye Brine believes that the fact that over 2.75 million barrels of produced saltwater have been injected into the Adams #3 well to date is evidence that the injection interval has sufficient permeability and porosity.

Class I wastes injected into the Adams #3 well in the future will be interacting initially with the injected produced saltwater as the native formation water has been displaced by the significant volumes (>10,000,000 bbls) injected into the three Adams wells since the beginning of operations in 2012.

KB ht is approximately 797 ft. ASL

Ground Level = 785 ft ASL



Schematic Drawing - Not to Scale

BELOW GROUND DETAIL

1. Conductor Casing: 42' of 16", ST&C. Cemented to surface.
2. Surface Casing: 842' of 11 3/4", ST&C. Cemented to surface.
3. Injection Tubing : 5910' of 4 ½" 10.5 #/ft J-55t To bottom of packer.
4. Protection/Longstring Casing (bottom to top): 6015' 8 5/8" LT&C 32# Cemented to surface. 10/19/2016 Caliper log discovered Bottom two joints slipped down. New total length now 5912 ft.
5. Packer: ASI-X Nickel internal Coated mandrel from 5902' to 5910'.
6. Fresh Water
   Annulus fluid with oxygen scavenger & corrosion inhibitor.
7. Cement: API CLASS A
8. Fill: Tagged Oct 2016 7065'
9. TD 7135'

Source: Titanium Environmental, LLC, 2017

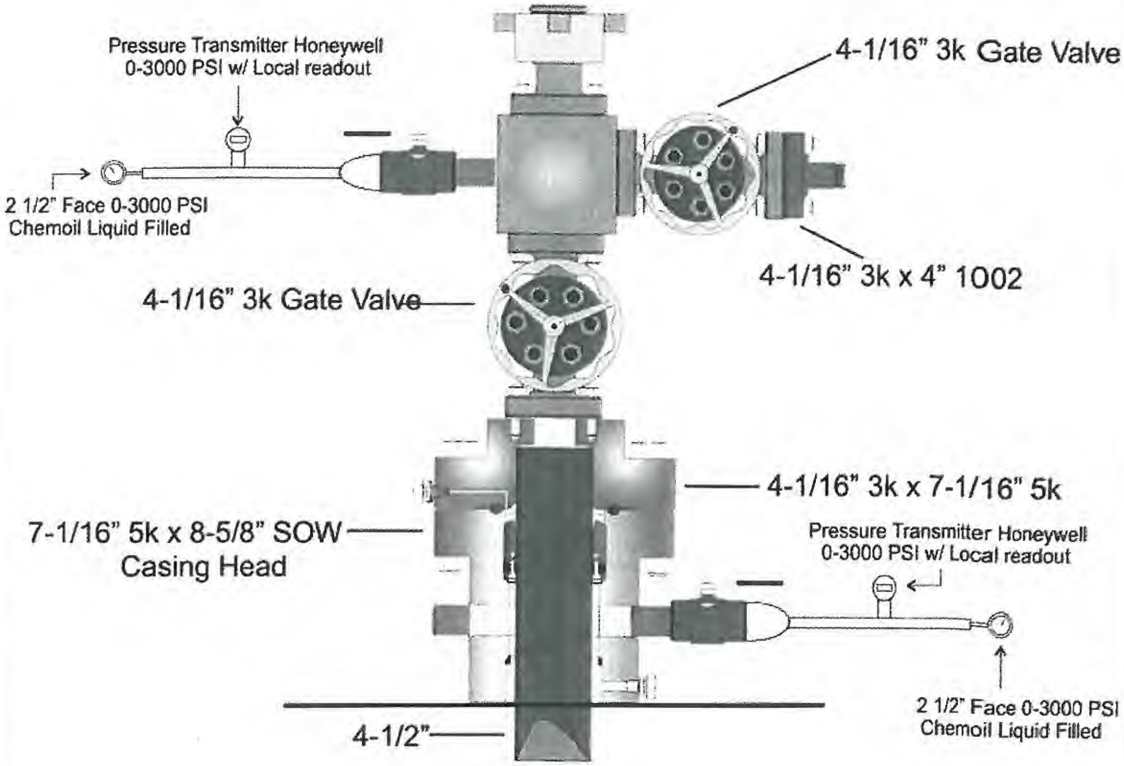
Bradley S. Pekas

STATE OF OHIO
BRADLEY PEKAS
E-83267
REGISTERED
PROFESSIONAL ENGINEER

SHEET 2A 4 OF 6 REV: B	ADAMS #3 - UIC WELL SCHEMATIC BUCKEYE BRINE,LLC COSHOCTON, OH	Trihydro CORPORATION 1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	DRAWN BY: DB CHECKED BY: BP DATE: 4/27/2018 SCALE: NONE FILE: 570-UIC_WELL-DETAILS	BRADLEY S. PEKAS, PG, PE SR. GEOLOGIST/ENGINEER OHIO PE NO. E-83267 OH ENGINEERING COA #01867 3740 ST. JOHNS BLUFF, SUITE 14 JACKSONVILLE, FL 32224 PHONE: 800-359-0251

REV.	DATE	DESCRIPTION	BY	CHK
B	04/27/18	FINAL	DB	BP
A	04/24/18	DRAFT	DB	BP

REVISIONS



Schematic Drawing - Not to Scale

Sources: Universal Wellhead Services, LLC 2017 and Titanium Environmental, LLC - 2018

Bradley S. Pekas

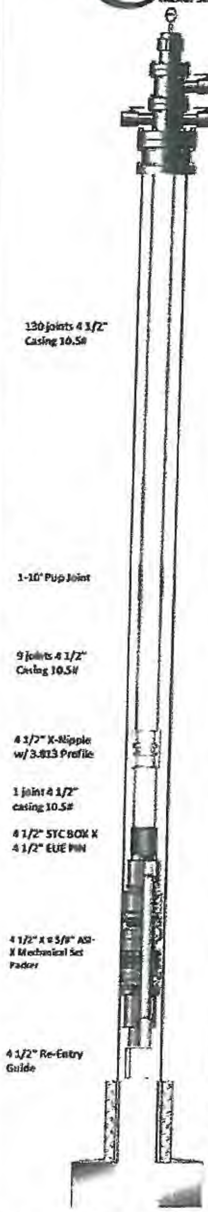
STATE OF OHIO BRADLEY PEKAS E-83267 REGISTERED PROFESSIONAL ENGINEER

SHEET 2B 5 OF 6	ADAMS #3 - WELLHEAD DESIGN	Trihydro Corporation 1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	DRAWN BY: DB	BRADLEY S. PEKAS, PG, PE SR. GEOLOGIST/ENGINEER OHIO PE NO. E-83267 OH ENGINEERING COA #01867 3740 ST. JOHNS BLUFF, SUITE 14 JACKSONVILLE, FL 32224 PHONE: 800-359-0251
			CHECKED BY: BP	
	BUCKEYE BRINE,LLC COSHOCTON, OH		DATE: 4/27/2018	
			SCALE: NONE	
REV: B			FILE: 57G-UIC_WELL-DETAILS	

REV.	DATE	DESCRIPTION	BY	CHK
B	04/27/18	FINAL	DB	BP
A	04/24/18	DRAFT	DB	BP

REVISIONS

BLUE DOT ENERGY SERVICES LLC



Buckeye Brine

Well Name: Adams	Well #3 SWI W #12 #3 SWI W #12	Date: 9/15/2014	KB
County: Coshocton	State: Ohio		
Company Rep. Rex Baker	Tool Operator: P. Dean		
Casing Size: 8 5/8"	Tubing Size: 4 1/2"		
Casing Weight: 36#	Tubing Weight: 10.5		
Casing Grade: P-110	Tubing Grade: J-55		

Quanity	Description	Max O.D.	Min I.D.	Length	TD of BOT
1	4 1/2" Re-Entry Guide	5.625	4.000	0.77	5925.41
1	4 1/2" X 8 5/8" ASI-X Mechanical Set Packer	7.500	4.000	7.95	5924.64
1	4 1/2" EUE Pin X 4 1/2" STC Box X-Over Sub	5.000	4.000	0.61	5916.69
1	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	42.20	5916.08
1	4 1/2" X-Nipple w/ 3.813 Profile	5.000	3.813	1.05	5873.88
9	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	379.80	5872.83
1	4 1/2" Pup Joint	5.000	4.052	10.00	5493.03
130	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	5483.03	5483.03
	Packer Set in 25K Compression				
	140 Joints Total in and 1-10' Pup Joint				
	10' Marker Joint 422' above Packer				
		Total Footage		5925.41	

Sources: Blue Dot Energy Services, LLC 2015 and Titanium Environmental, LLC - 2017

Schematic Drawing - Not to Scale

Bradley S. Pekas — Digitally signed by Bradley S. Pekas

STATE OF OHIO — BRADLEY PEKAS E-83267 — REGISTERED PROFESSIONAL ENGINEER

SHEET 2C 6 OF 6 REV: B	ADAMS #3 - PACKER ASSEMBLY / BUCKEYE BRINE, LLC COSHOCTON, OH	Trihydro Corporation 1252 Commerce Drive Laramie, Wyoming 82070 www.trihydro.com (P) 307/745.7474 (F) 307/745.7729	DRAWN BY: DB; CHECKED BY: BP; DATE: 4/27/2018; SCALE: NONE; FILE: STG-UIC_WELL-DETAILS	BRADLEY S. PEKAS, PG, PE SR. GEOLOGIST/ENGINEER OHIO PE NO. E-83267 OH ENGINEERING COA #01867 3740 ST. JOHNS BLUFF, SUITE 14 JACKSONVILLE, FL 32224 PHONE: 800-359-0251

REV.	DATE	DESCRIPTION	BY	CHK
B	04/27/18	FINAL	DB	BP
A	04/24/18	DRAFT	DB	BP

REVISIONS

Attachment D

Operating, Monitoring, and Reporting Requirements

Adams #3

CHARACTERISTIC REQUIREMENTS	LIMITATION		MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
	Maximum	**Minimum**	**Frequency**	**Frequency**
*Maximum Allowable Injection Pressure Not to be exceeded	1362 psig		continuous	monthly
**Bottom-hole Pressure $_{(max)}$	4434 psig		*calculated	monthly
Annulus Pressure	50 psig higher than injection pressure throughout entire tubing length from the surface to the top of the packer		continuous	monthly
Flow Rate	290 gpm (combined monthly average)		continuous	monthly
***Flow Volume			continuous	monthly
Temperature			continuous	monthly
Specific Gravity			continuous	monthly
Sight Glass Level			daily	monthly
Corresponding Annulus Pressure			daily	monthly
Corresponding Waste Temperature			daily	monthly
Corresponding Injection Pressure			daily	monthly
Corresponding Flow Rate			daily	monthly
pH			daily	monthly
****Chemical Composition of Injectate			monthly	monthly

*Injection Pressure: (maximum allowable surface injection pressure = MASIP)

MASIP = 5912 x [0.75 - (0.433 x 1.2)] where:

5912 = depth to the top of the injection interval in true vertical depth feet

0.75 = applied fracture gradient in psi/ft

.443 = Pressure Gradient of 1 Foot of Water at 62 Degrees Fahrenheit

1.2 = fluid specific gravity

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

BHP_{max} = (0.75) (5912)

***Flow Volume: The combined monthly injection volume for the Class I wells on site must not exceed 12,710,700 million gallons, unless otherwise approved by the Director.

**** Chemical Composition: Chemical analysis shall be conducted for parameters which characterize the waste water and in accordance with the Sampling and Waste Analysis Plan after it is approved by the Director. Include monthly analysis with monthly report each month.

Attachment E

CORRECTIVE ACTION
(OAC Rules 3745-34-07 and 3745-34-30)

Protection of USDW

Should upward fluid migration occur through the wellbore of any previously unknown, improperly plugged or unplugged well in the area of review as a result of injection of fluids through the permitted well or should this migration of fluids threaten to contaminate an USDW, the injection well shall be shut-in until proper plugging can be accomplished. The Director shall determine the adequacy of the proposed corrective action of the Corrective Action Plan. 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. If data from the ground water monitoring activities or other relevant data indicate either the upward migration of fluids from the injection interval, or a threat to or contamination of an USDW, the Director may require corrective action.

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for injection Well Permit Number UIC 04-16-018-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 ______________________________

Name of Company

ATTACHMENT G

Ground Water Monitoring

Ground Water Monitoring Constituents

- For the initial sampling only, Volatile Organic Compounds as determined by analysis using US EPA Method 8260.
- pH, Specific Conductance, and Temperature to be taken in the field every time a sample is collected.
- For all samples collected analyze for Boron, Calcium, Chloride, Fluoride, Total Dissolved Solids, Sulfate, Sodium, Ammonia, Iron, Manganese, and Potassium.

Ground Water Monitoring Well Requirements

The monitoring well shall be designed, installed, and developed in a manner that allows the collection of ground water samples that are representative of ground water quality in the lowermost underground source of drinking water (USDW) and that are in accordance with the following criteria:

(a) The monitoring well shall be cased in a manner that maintains the integrity of the monitoring well boreholes.

(b) The annular space (i.e., the space between the borehole and the well casing) above the sampling depth shall be sealed to prevent the contamination of the samples and the ground water.

(c) The casing shall be screened or perforated and surrounded by sand or gravel in such a way that allows for the following:

(i) For the minimization of the passage of formation materials into the well.
(ii) For the monitoring of discrete portions of the lowermost underground source of drinking water.

SAMPLING AND ANALYSIS PROCEDURES

The sampling and analysis plan shall include copies of all blank forms necessary and a detailed description of the equipment, procedures, and techniques to be used to do the following:

(A) Are designed to ensure monitoring results that provide an accurate representation of the ground water quality in the lowermost USDW.

(B) The owner or operator shall include a description of the sample withdrawal technique including location of sampling, sampling device used, sample containers used, and sample handling and preservation for each sample obtained.

(C) Perform field analysis for temperature, pH, and specific conductance for each sample, including the following:

(1) Procedures and blank forms for recording field measurements that include the specific location, time, and site-specific conditions associated with the field data acquisition.

(2) Procedures used for the calibration of field devices and blank forms for the documentation of calibration procedures.

(D) Decontaminate all non-dedicated and non-disposable monitoring, purging, and sampling equipment prior to use

(E) Establish the chain of custody for the samples. The chain of custody form must be included with the sampling and analysis plan and shall note:

(1) Name of the facility and facility identification number as assigned by Ohio EPA, if applicable

(2) Field sample identification number for each sample.

(3) Date and time each sample was collected.

(4) The printed name and signature of each person having custody of the sample prior to its analysis with the exception of a person employed by a commercial carrier contracted to transport the ground water samples to the laboratory.

(5) The date and time that each person receives custody of the ground water sample, including the date and time the sample is relinquished to the laboratory.

(6) Chemical preservatives added to the sample.

(7) Whether ice is present or the internal temperature of each cooler when received by the laboratory.

(8) All special instructions regarding sample handling, preservation, analysis, or other information that needs to be documented to ensure that the associated sample analytical results will be representative.

(F) Obtain field quality control samples.

(G) Obtain all of the information required to be recorded on the sampling form. A copy of the blank sampling form shall also be included.

SUBMISSION OF ANALYTICAL DATA

The following information shall be submitted to and received by Ohio EPA in a form specified by the director:

(A) All results generated and information recorded in accordance with the approved sampling and analysis plan.

(B) Laboratory data sheets. The laboratory data sheets shall include at a minimum the following:

(1) Name of the facility.

(2) Field sample identification number for each ground water sample.

(3) Laboratory sample identification number for each ground water sample.

(4) Sampling date.

(5) Date the laboratory received the sample.

(6) Analytical method identification numbers for all parameters.

(7) Sample extraction date, if applicable.

(8) Sample analysis date.

(9) Analytical results for all parameters including method detection limits (MDLs), practical quantitation limits (PQLs) and any laboratory estimated values.

(10) Laboratory data qualifiers, if applicable.

(11) Sample dilution factor, if applicable.

(12) Laboratory quality control information. This information shall include at a minimum the following:

(a) Case narrative describing each problem that was encountered between sample receipt and the completion of sample analysis.

(b) Field and laboratory sample identification numbers.

(c) Holding times specified in the sampling and analysis plan for each parameter, or a statement by the laboratory that all holding time requirements were met.

(d) Whether meniscus bubbles were present in any volatile organic sample containers when received by the laboratory.

(e) Surrogate and spike recoveries with control limits.

(f) Data results from the analysis of blank samples including trip blanks, method blanks, and, if required, instrument blanks with control limits.

(g) Data from the analysis of matrix spike/matrix spike duplicates (MS/MSD) and matrix spike blanks with control limits.

(h) Relative percent difference calculations based on MS/MSD results.

(i) Laboratory control sample results if the metals spike recovery results are determined to be out of control.

(C) Data summary tables. The data summary tables shall include mine water elevation data and the analytical data collected from the sampling event applicable to the data submission and may include previously submitted data from past sampling events.