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DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I HAZARDOUS WELL

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

By: Dina Lassiter Date: 5-15-13

Ohio Permit No.: UIC 05-09-001-PTO-I
US EPA ID No.: OHD004234480

Date of Issuance: - May 15, 2013
Effective Date: - May 17, 2013

Date of Expiration: - May 17, 2019

Name of Applicant:	AK Steel Corporation (Well Number 1)
Mailing Address:	1801 Crawford Street Middletown, Ohio 45043
Facility Location:	1801 Crawford Street Middletown, Ohio 45043
County:	Butler **Township:** Lemon
Lot:	1,054.6 feet from North line; 64.7 feet from West line of NW/4 Section 8, Lemon Township
Latitude/Longitude:	39° 29' 09" N / 84° 21' 20"W
Injection Interval:	Eau Claire, Mt. Simon and Middle Run Formations from 2900 feet to 3296 feet
Containment Interval:	Eau Claire Formation from 2423 feet to 2900 feet
Injection Zone:	Eau Claire, Mt. Simon, and Middle Run Formations from 2423 feet to 3296 feet
Confining Zone:	Knox Formation from 1172 feet to 2423 feet

NOTE: All depths are measured from the Kelly Bushing (KB). KB elevation = 666 feet above sea level. Ground level elevation = 658.6 feet above sea level.

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

The following attachments are incorporated into this permit: A, B, C, D, E, F.

This permit shall become effective on May 17, 2013 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.

Scott J. Nally, Director
Ohio Environmental Protection Agency

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PART I

GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in operation of underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDW). Any underground injection activity not specifically authorized in this permit is prohibited. Compliance with this permit during its term constitutes compliance for purposes of enforcement with Sections 6111.043 and 6111.044 of the Ohio Revised Code (ORC). Such compliance does not constitute a defense to any action brought under ORC Sections 6109.31, 6109.32 or 6109.33 or any other common or statutory law other than ORC Sections 6111.043 and 6111.044. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of state or local law.

Nothing in this permit relieves owners and operators of underground injection wells of their obligation to comply with requirements under applicable state and federal law or regulations.

This permit does not authorize any above ground generating, handling, storage, treatment or disposal facilities. Such activities must receive separate authorization under regulations promulgated pursuant to Chapter 3745 of the Ohio Administrative Code (OAC) and Part C of the federal Resource Conservation and Recovery Act or other applicable state or federal regulations.

B. PERMIT ACTIONS

1. <u>Modification, Revocation, Reissuance and Termination</u>. The Director may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with OAC Rules 3745-34-07, 3745-34-23, and 3745-34-24. Also, the permit is subject to minor modifications for causes specified in OAC Rule 3745-34-25. The filing of a request for a permit modification, revocation and reissuance, or termination, or notification of planned changes, or anticipated noncompliance on part of the permittee does not stay the applicability or enforceablity of any permit conditions or applicable state or federal requirements.

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, 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 Code of Federal Regulations (CFR) Part 2 and OAC Rule 3745-34-03, any information submitted to the Ohio EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, the Ohio EPA may make the information available to the public without further notice. If a claim is asserted, documentation for the claim must be tendered and the validity of the claim will be assessed in accordance with the procedures of 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 noncompliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. Any permit noncompliance constitutes a violation of ORC Chapter 6109. or 6111. and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or denial of a permit renewal application. Such noncompliance also may be grounds for enforcement action under other applicable state and federal law.

2. Penalties for Violating Permit Conditions. Any permittee who violates a permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapters 6109., 6111.. 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 conditions of an expired permit shall continue in force in accordance with ORC Section 119.06 until the effective date of a new permit, if:

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

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

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

4. <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 necessary steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit. This may include accelerated or additional monitoring or testing or both. If such is performed, the data collected shall be submitted to Ohio EPA in a written report within 90 days of completion of all related activities.

6. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. "Proper operation and maintenance" includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. Duty to Provide Information. The permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for renewing, modifying, revoking and reissuing, terminating this permit, or to determine compliance with this permit. The permittee also shall furnish to the Director, upon request, copies of records required to be kept by this permit 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. Have access to and photograph, at reasonable times, any activity related to the injection operation. This includes monitoring/testing equipment or any other operation regulated under the conditions of this permit;

   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 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 years from the date of the sample, measurement or report, or for the duration of the permitted life of the well, whichever is longer. This period may be extended by the request of the Director.

b. The permittee shall maintain copies of records of all data required to complete the permit application form for this permit and any supplemental information submitted under OAC Rules 3745-34-12, 3745-34-13, and 3745-34-15 for a period of at least five 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 II(D) of this permit until three years after the completion of well closure which has been carried out in accordance with the approved Closure Plan.

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

e. Records of all 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. <u>Monitoring.</u> 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, and in accordance with Part II(E) of this permit, 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, or requested by 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.

b. Anticipated Noncompliance. The permittee shall give advance notice to the Director, as soon as possible, of any planned changes in the permitted facility or any 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. Replacement of equipment that is equivalent to existing equipment is not included in this requirement. 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 30 days following each schedule date.

d. Twenty-four 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 business days of the time the permittee becomes aware of instances of noncompliance identified in paragraph Part I(E)(12)(d) 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 Part I(E)(12)(d)(ii) above.

f. Monthly reports specified in OAC Rule 3745-34-38 and Part II(E)(1) of this permit shall be submitted to Ohio EPA by the fifteenth day of the following month. Semi-annual and quarterly reports shall be submitted in accordance with Part II(E)(2) of this permit.

g. Within 30 days of receipt of this permit, the person(s) 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 has changed.

F. CLOSURE (OAC Rules 3745-34-27, 3745-34-36, and 3745-34-60)

1. <u>Closure Plan</u>. A plan for closure of the well that includes assurance of financial responsibility and information relating to well closure is required in accordance with OAC Rules 3745-34-27, 3745-34-36, and 3745-34-60. The implementation of the approved Closure Plan (Attachment A) is a condition of this permit; however, the permittee must receive the approval of the Director to proceed before implementing this plan. The permittee shall maintain and comply with this plan and all applicable requirements. The obligation to implement the Closure Plan survives the termination of this permit or the cessation of injection.

2. <u>Revision of Closure Plan</u>. The permittee shall submit any proposed revisions to the methods of closure described in the Closure Plan for approval by the Director no later than 60 days before closure, unless a shorter period of time is approved by the Director.

3. <u>Notice of Intent to Close.</u> The permittee shall notify the Director at least 60 days prior to 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 24 months may keep the well open only if the permittee:

   a. Has received written authorization from the Director; and

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

   If the owner or operator has ceased operations for more than 24 months, the permittee shall notify the Director at least 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 60 days of the completion of the well closure activities. The report shall be certified as accurate by the permittee and by the person(s) who performed the closure operation by including the certification language of OAC Rule 3734-34-17. Such report shall consist of the results of activities conducted by the permittee as required by Parts I(F)(6)(a) and (b) of this permit, and:

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

   b. Where actual Ohio EPA approved Closure Plan deviations occurred, the permittee shall provide a written statement detailing the differences between the original plan and any plan deviation(s).

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;

b. Conduct mechanical integrity testing of the well to ensure the integrity of that portion of the long string casing and cement that will be left in the ground after closure. At the discretion of the Director, testing methods may include:
   i. Pressure tests with liquid or gas;
   ii. Radioactive tracer surveys;
   iii. Noise, temperature, oxygen activation, pipe evaluation or cement bond logs; and/or;
   iv. Any other test(s) 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 3745-34-27(B)(7). The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection.

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

1. Post-Closure Plan. A plan for post-closure activities, including assurance of financial responsibility, is required. The permittee shall comply with the plan as if it were fully set forth herein. The obligation to implement the Post-Closure Plan survives the termination of this permit or the cessation of injection. Prior to well closure, AK Steel shall amend its Post-Closure Plan to include the following requirements:

   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.

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

3. <u>Duration of Post-Closure Period</u>. The permittee shall, at a minimum, continue post-closure maintenance and monitoring of any ground water monitoring wells required under this permit until 12 months after cessation of injection into all Class I UIC wells at this site. At the conclusion of the twelve month post-closure monitoring period, the permittee shall submit a formal request to the Director requesting termination of the post-closure monitoring obligations. This request must be supported by demonstrating that the cone of influence does not intersect the base of the lowermost source of underground drinking water.

4. <u>Survey Plat</u>. The permittee shall submit a plat map to the local zoning authority upon closure of the well in accordance with the approved Closure Plan required by 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. <u>Notification to State and Local Authority</u>. The permittee shall provide appropriate notification and information to the Ohio Department of Natural Resources - Division of Mineral Resource Management, the Butler County Board of Health, and any other state or local authority designated by the Director upon closure of the well in accordance with the approved Closure Plan.

6. <u>The Retention of Records</u>. The permittee shall retain, for a period of three 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. <u>Notice of Deed to Property</u>. Upon closure of the well in accordance with the approved Closure Plan required in Part I(F) of this permit, the permittee shall record a notation on the deed to the facility property, or on some other instrument which is normally examined during a 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 of 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.

H. MECHANICAL INTEGRITY

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

2. Periodic Mechanical Integrity Testing [OAC Rule 3745-34-57]. The permittee shall conduct the mechanical integrity testing as follows:

   a. Long string casing, injection tubing and annular seal shall be tested by means of an approved pressure test conducted annually between June 1 and July 31 of each year the well is operated under this permit with the exception of 2013 when the test shall be conducted prior to June 7, 2013, and whenever there has been a well work over 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 Ohio EPA approved radioactive tracer survey conducted annually between June 1 and July 31 of each year the well is operated under this permit with the exception of 2013 when the test shall be conducted prior to September 30, 2013;

   c. An approved temperature, noise or other approved log shall be run at least once every three years between June 1 and July 31 beginning with June 2012 as the last approved demonstration to test for movement of fluid along the borehole. The Director may require such tests whenever the well is worked over;

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

   e. The permittee may request to use any other test approved by the Administrator of the U.S. EPA in accordance with the procedures in OAC Rule 3745-34-34(D). The Director will make the final determination as to what test(s) are acceptable.

f. In accordance with OAC Rule 3745-34-34(G), the Director may require additional or alternative tests if the results presented are not satisfactory.

3. <u>Prior Notice and Report</u>.

a. The permittee shall notify the Director in writing of its intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. The notice shall be in the format of a testing plan. For those tests required in Part I(H)(2)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 the results by a knowledgeable log analyst. Such reports shall be submitted in accordance with the reporting requirements established by Part II(E)(3) of this permit.

b. The permittee shall submit a plan for approval to the Director prior to conducting any well work over which requires the removal of the injection tubing. This plan shall be submitted 45 days prior to plan implementation. A shorter time period may be allowed at the Director's discretion.

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

d. All plans required to be submitted for the Director's approval must be followed. The permittee shall notify Ohio EPA prior to any deviation from the Ohio EPA approved testing plans in accordance with Part I(E)(12)(b).

4. <u>Gauges</u>. The permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half (0.5) percent of full scale prior to each required test, or barring any damage to the gauge, every six months. A copy of the calibration certificate shall be submitted to the Director or his representative at the time of demonstration and every time the gauge is calibrated. The gauge shall be marked in no greater than five psi increments.

5. <u>Loss of Mechanical Integrity</u>. If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, fails to maintain mechanical integrity at any time, or the permittee fails to perform required mechanical integrity testing within the required timeframes, the permittee shall halt the operation immediately and follow the reporting requirements as in accordance with Part I(E)(12) of this permit. The permittee shall not resume

operation until mechanical integrity is satisfactorily demonstrated to Ohio EPA and the Director gives approval to recommence injection.

6. Mechanical Integrity Testing on Request from the Director. Upon written request from the Director, the permittee shall demonstrate mechanical integrity at any time.

I. FINANCIAL RESPONSIBILITY

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC Chapter 3745-34. In accordance with OAC Rule 3745-34-36(D)(1)(c) and Rule 3745-34-36(D)(2)(c), the permittee is required to provide evidence of financial responsibility acceptable to the Director of Ohio EPA.

   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, and Rules 3745-66-42 to 3745-66-48, or Rules 3745-55-42 to 3745-55-51 of the OAC as applicable. The closure and post-closure cost estimates shall equal (at a minimum) 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. The inflation factor is derived from the most recent "Implicit Price Deflator for Gross National Product" published by the U.S. Department of Commerce. This annually adjusted closure and post-closure cost estimate shall be submitted with the annual financial assurance to the Director as applicable.

   c. The permittee shall revise the closure and/or post-closure cost estimates within 30 days whenever a change in the Closure Plan and/or Post-Closure Plan increases the cost of closure and/or post-closure. The current closure and post-closure cost estimate shall be based on costs to a "third party," the company expected to perform the plugging and abandonment activity.

   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 30 days.

   e. The permittee shall keep on file at the facility a copy of the latest closure and post-closure cost estimates prepared in accordance with OAC Chapter 3745-34 during the operating life of the facility. Said estimate shall be available for inspection in accordance with Part I(E)(8)(b) of this permit.

2. Insolvency. In the event of:

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

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

c. The institution issuing the financial mechanism losing its authority to issue such an instrument, the permittee shall notify the Director, in writing, within 10 days. The owner or operator shall establish other financial assurance or liability coverage acceptable to the Director, within 60 days after such an event.

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

J. CORRECTIVE ACTION

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

K. FEES

The permittee shall submit required fees in accordance with OAC Rule 3745-34-63 and shall submit any other applicable Class I Underground Injection fees. These said fees are non-refundable under any circumstance.

PART II

WELL SPECIFIC CONDITIONS FOR UIC PERMITS

A. CONSTRUCTION

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

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

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

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

B. FORMATION DATA

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

   a. Formation fluid pressure;

   b. Estimated formation fracture pressure and;

c. Physical and chemical characteristics of the formation.

2. In accordance with OAC Rule 3745-34-57(J), the permittee shall monitor the pressure buildup in the injection zone annually between June 1 and July 31 of each year the well is operated under this permit with the exception of 2013 when the test shall be conducted prior to September 30, 2013. Should the permittee fail to test within the required time frame, it shall halt the operation immediately and not resume until the test is completed. The permittee shall alternate well testing to ensure Well Number 1 is tested in odd numbered years and Well Number 2 is tested in even numbered years. The testing shall include, at a minimum, a build up time and a fall off 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 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 subsurface interval between 2900 and 3296 feet below kelly bushing (KB) for AK Steel Corporation Deepwell Number 1.

2. Injection Pressure Limitation [OAC Rules 3745-34-38(A) and 3745-34-56(A)].

   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 USDW.

   b. Bottom hole pressure shall be limited so that a maximum of 2175 psig (calculated at 2900 feet GL, using a fluid specific gravity of 1.240 and with a fracture gradient of 0.75 psi/foot applied is never exceeded. Injection pressure shall be limited so that a maximum pressure at the surface is not exceeded. Current maximum allowable surface injection pressure is 100psi based on the existing UIC well monitoring system and as described in the Ohio EPA approved UIC Monitoring Plan. The UIC Monitoring Plan may be revised or amended by the permittee to allow a maximum surface injection pressure up to 618psi subject to Ohio EPA approval of the plan revision or amendment. The maximum surface injection pressure shall be adjusted based on the injection fluid specific gravity to assure continuous compliance with the calculations set forth in Attachment D of this permit.

The initiation and propagation of fractures, except during a controlled stimulation, is strictly prohibited by OAC Rules 3745-34-27(B)(2), 3745-34-38(A)(1), and 3745-34-56(A).

3. Additional Injection Limitation. No waste other than the permittee's permitted waste stream as described in the Waste Analysis Plan and as characterized in Part II(D) of this permit shall be injected into this well. The only exception to this limitation is the injection of fluids approved by Ohio EPA for well testing and/or monitoring, or fluids approved by Ohio EPA for well treatment/stimulation. The combined monthly average injection rate for all permitted deep injection wells shall not exceed 60 gallons per minute or as otherwise specified by the most current USEPA Landban Exemption.

4. Annulus Fluid and Pressure [OAC Rule 3745-34-38(A)(3)]. Except during work overs, or during other Ohio EPA approved procedures, 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 a minimum of 50 psig higher than the injection pressure at the same point at all times throughout the injection tubing length to the top of the packer/seal assembly for the purpose of leak detection.

5. Automatic Warning and Shut-Off System.

   a. The permittee has submitted a UIC Well Contingency Plan that includes a description of the injection well automatic warning and shut-off system that has been determined by Ohio EPA to meet the requirements of OAC Rule 3745-34-56(F). The permittee shall continuously operate and maintain the automatic warning and shut-off system as described in the most current, Ohio EPA approved Contingency Plan. The system shall sound warning alarms and 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;
      ii. When annulus pressure falls below 50psig positive differential from the injection pressure and during conditions specified above in Part II(C).

b. The permittee shall test the automatic warning and shut-off system at least once every twelfth month from the date of the last approved demonstration. The testing shall involve subjecting both injection wells to partial simulation shutdown in even numbered years and full simulation shutdown in odd numbered years. "Partial simulation" means that flow is occurring to the well, a signal is introduced to trigger the system, and the valves to the wells close to shut off injection. "Full simulation" means that no injectate flow is occurring, a signal is introduced to trigger the system, and the valves to the wells close. This test shall be witnessed by the Director or his or her representative. The permittee shall notify the Director of its intent to test the automatic warning and shut-off system at least 30 days prior to such 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 and/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;
   ii. Take all necessary steps to determine the presence or absence of a leak; and
   iii. Notify the Director within twenty-four hours after alarm or shutdown in accordance with Part I(E)(12) of this permit.

6. <u>Precautions to Prevent Well Blowouts</u>. The permittee shall, at all times, excluding Ohio EPA approved instances, maintain a pressure at the wellhead which will prevent the return of the injection fluid to the surface. If there is gas formation in the injection zone near the well bore, such gas must be prevented from entering the casing or tubing. The well bore must be filled with a high specific gravity fluid during work overs to maintain a positive (downward) gradient and/or a temporary plug shall be installed which can resist the pressure differential. A blowout preventer shall be kept in proper operational status during work overs.

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 required monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rules 3745-34-38 and 3745-34-57(A-F), Attachment D, and any other monitoring required by applicable rule or this permit at a frequency sufficient to yield representative data. Monitoring results shall be reported in accordance with OAC Rule 3745-34-38 in a format acceptable to the Director.

   a. 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 Table 1 of 40 CFR Part 136.3 and/or Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Director.

   b. The monitoring information shall include conditions of quality assurance for each type of measurement required for reporting by the operator.

   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.

2. Injection Fluid Analysis [OAC Rules 3745-34-38 and 3745-34-57].

   a. The injected fluids shall be analyzed no less frequently than quarterly for parameters listed in the approved Waste Analysis Plan. Results of the most recent analyses shall be submitted with each monthly operating report.

   b. Injected fluids shall be analyzed continuously for temperature and in accordance with OAC Rule 3745-34-57 and Attachment D of this permit.

3. Waste Analysis Plan [OAC Rule 3745-34-57].

   a. The permittee has developed a written Waste Analysis Plan which describes the procedures that will be carried out to comply with permit conditions Part II (D)(1) and (2) above and Rule 3745-34-57 of the OAC. A copy of the plan shall be kept at the facility and be available for inspection. The sampling and analyses shall be performed in a manner consistent with the Ohio EPA Quality Assurance Plan requirements. At a minimum, the plan must specify:

      i. The parameters for which 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;

iii. The sampling methods which will be used to obtain a representative sample of the waste to be analyzed, the frequency of sampling and analysis for each parameter; and
iv. The injectate sampling location.

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 shall be completed and submitted to the Director within 30 days of the effective date of this permit. The permittee shall assure that the Waste Analysis Plan (WAP) remains accurate and the analyses of any fluid sampled remain representative as required by OAC Rule 3745-34-57(D).

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

i. Restrict certain incompatible wastes from being injected;
ii. Require the permittee to make appropriate changes in well construction materials

4. <u>Continuous Monitoring and Recording Devices [OAC Rule 3745-34-38(B)(2)]</u>. The permittee shall follow the deepwell 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 deepwell 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 monitor the ground water monitoring well for parameters and at the frequency described in the approved Ground Water Monitoring Plan (GWMP) and shall analyze the data according to procedures and at the frequency described in the approved GWMP. Additional monitoring wells, additional sampling and/or appropriate corrective action may be required upon a determination of the Director, based upon data submitted in accordance with this permit and any additional pertinent data, that such monitoring and/or action are necessary to determine whether an USDW may be endangered. A copy of the most recently approved plan shall be kept at the facility and be available for inspection.

6. Seismic Monitoring.

a. Seismic Reflection Data. The permittee submitted a seismic reflection data study in March of 1992. The purpose of this study was to attempt 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 Middletown, Ohio Class I injection well facility.

Should the area of review for this facility change during the operational life of this well, the permittee shall re-evaluate the data obtained from the existing study to ascertain whether additional seismic reflection surveys are necessary to ensure safe injection operations. In the event that the evaluation of the seismic data within the re-designated area of review is determined 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 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.

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 a minimum of the following information listed below in a format acceptable to the Director.

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

   i. Any noncompliance with conditions of the permit including but not limited to events that violate maximum or minimum limits for surface injection pressure, bottom hole pressure or annulus pressure. This includes both anticipated and unanticipated noncompliance. Report the date, time, the nature and cause of the noncompliance and the response taken;
   ii. Any event which triggers an alarm or shutdown device required in Part II(C)(5) of this permit. Report the date, time, cause of the alarm or shutdown, the alarm or shutdown setpoint, the actual value triggering the alarm or shutdown, the response taken and specify whether an alarm and/or shutdown occurred;
   iii. Any non-operating period. Report the date, duration and specific cause of the non-operating period;
   iv. Any procedures conducted at the injection well other than routine procedures. Report the date and the reason for the non-routine operating procedures. For the purpose of this permit, non-routine is considered to be a procedure/activity that does not occur on a daily basis;
   v. Any annulus fluid addition to or removal from the annulus system. Report the date, the time and cause for the addition or removal, the volume of fluid added or removed and specify fluid type;
   vi. Any fluids added to act as a corrosion inhibitor between the packer/injectate interface. Report the date, time, volume, and fluid type;
   vii. Any mechanical integrity testing. Report the date, the reason for the testing, type of test(s), and briefly summarize the results of the test(s);
   viii. Any well work over. Report the date, the reason for the work over and the work completed; and
   ix. Any other testing of the injection well required by the Director. Report the date, the reason for testing and the type of test(s).

b. A graph showing, in contrasting symbols or colors, for each day of the month:
   i. Maximum surface injection pressure;
   ii. Maximum bottom hole pressure; and
   iii. Minimum annulus pressure.

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

c. Daily injectate specific gravity.

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

e. The total volume of fluid injected into this well for the reporting month and to date. This includes volumes injected during any well testing or stimulation procedures.

f. The cumulative volume of fluid injected at the facility for the reporting month and to date.

g. The status of and scheduled date(s) for sampling of UIC ground water monitoring wells. The permittee shall notify Ohio EPA, in writing, of its intentions to sample 14 days prior to the scheduled date of sampling.

h. Results of injection fluid analyses, specified in Part II(D)(2)(a) and (b) of the permit, completed during the month.

2. Quarterly and Semi-Annual Reports [OAC Rule 3745-34-58(B)]. The permittee shall report all results of ground water monitoring conducted as required by Part II(D)(5) of this permit, to the Director within 15 days following the end of the quarter in which the sampling was conducted. Results of the injectate analyses as stipulated in Part II(D)(3) of this permit and the corrosion monitoring shall also be reported to the Director within 15 days following the end of the quarter in which the monitoring was conducted.

3. Reports on Well Tests and Work Overs. Within 30 days after the activity, the permittee shall submit to the Director, the field results of demonstrations of mechanical integrity, or results of other tests required by this permit, any well work over, or formation treatment/stimulation. A formal written report and interpretation of demonstrations of mechanical integrity (excluding annulus pressure tests), any well work over, pressure buildup/fall-off monitoring, well treatment, or results of other tests required by this permit or otherwise required by the Director shall be submitted to the Director within 45 days after completion of the activity.

The Permittee shall submit all required reports and other correspondence to:

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

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 as well as applicable reporting requirements under OAC Chapter 3745-34.

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 years, the permittee is required to submit to the Director a revised Executive Summary of the plan.

ATTACHMENT A

I. Closure Plan With Cost Estimates

II. Post-Closure Plan With Cost Estimates

III. Financial Assurance

CLOSURE PLAN
Underground Injection Control Wells Number 1 and Number 2

Prepared for:

AK Steel

AK Steel Corporation
Middletown Works
1801 Crawford Street
Middletown, Ohio 45043-0001

Prepared by:

KEMRON
ENVIRONMENTAL SERVICES

KEMRON Environmental Services, Inc.
2343-A State Route 821
Marietta, OH 45750

and

Petrotek

Petrotek Engineering Corporation
10288 W. Chatfield Ave. #201
Littleton, CO 80127

February 2012

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1.0 INTRODUCTION

AK Steel Corporation (AK Steel) submits the following plan for closure of two Class I injection wells operated at the Middletown Works, Butler County, Middletown, Ohio. This plan has previously been submitted by AK Steel and approved by OEPA in 1991, 1996, 1997 and 2007 and much of the content was originally developed by Subsurface Technology, Inc. in accordance with Part I (F)(1) through (6) of the current AK Steel UIC operating permits issued by the Ohio Environmental Protection Agency (OEPA), and as required by Ohio Administrative Code (OAC) Rule 3745-34-60. Section 3.0 of this closure plan summarizes the testing procedures that will be used to evaluate the integrity of the wells prior to abandonment. In addition, the plugging procedure presented in the permit application and intended to prevent movement of fluids above the injection zone is presented in Section 4.0. AK Steel financial responsibility is also addressed.

2.0 BACKGROUND INFORMATION

AK Steel has operated two Class I deep injection wells utilized for disposal of spent pickle liquor since 1969. Both wells are currently used as needed. Detailed information regarding the AK Steel injection well facility is contained in the AK Steel OEPA permit renewal document submitted in 1996, and amended in 2002. Additional details of the injection wells are provided in the petition for exemption from the Resource Conservation and Recovery Act land disposal restrictions (*UIC Petition Reissuance for AK Steel Well No. 1 and No. 2*, Subsurface, 2006), as approved by USEPA in 2008.

AK Steel shall notify the Director of its intent to close one or both injection wells and of any proposed changes to the existing Closure Plan no later than sixty (60) calendar days before closure, unless a shorter period of time is approved by the Director. If AK Steel wishes to interrupt injection activities for longer than 24 months, AK Steel will request authorization from the Director to keep the wells open. In addition, AK Steel would comply with the requirements applicable to active injection wells unless these requirements were waived by the Director in writing.

2.1 Well Construction and Completion Data

Standard oil field techniques and procedures were used to drill and complete both wells using materials, where needed, which are matched to the effluent being handled.

Both injection wells are similar in construction with the exception of a 7" liner in Well No. 2. In both wells, all USDWs are protected with a minimum of two (2) casing strings. All casing strings are cemented from the base to surface with cement that is designed to be compatible with its adjacent subsurface environment and the injection operation. The wells are completed with injection tubing and packers and are monitored on a continuous basis to ensure mechanical integrity. Injection takes place into the deepest sedimentary formation available at the site. Periodic mechanical integrity tests performed under the latest environmental regulatory guidelines have shown the packer, tubing, and casing to be sound and have shown no evidence of any external concerns based on the absence of vertical channels in the long-string casing cement.

2.2 Geologic and Hydrologic Information

The lowermost Underground Source of Drinking Water (USDW) within the Area of Review is the Cincinnatian Formation. At Well No. 1, the base of the USDW has been estimated at 492 feet BGL. Ground water stored within the Cincinnatian quickly deteriorates in quality with depth. Log analysis indicates that the lower few hundred feet of the formation contains water in excess of 10,000 ppm total dissolved solids (TDS).

The injection interval in the vicinity of AK Steel consists of the lower 79 feet of the Cambrian Eau Claire Formation, the entire Mt. Simon Sandstone, and the upper 60 feet of the Precambrian Middle Run Formation. The injection interval, approximately 396 feet thick in the Well No. 1, is composed of sandstone and lithic arenite.

The arrestment interval is the upper portion of the injection zone in which the upward movement of injected waste is arrested during both the operational lifetime and long-term no-migration projections. The arrestment interval at the AK Steel site consists of the upper 477 feet of the Eau Claire Formation as measured in the Well No.1.

The confining zone contains a sufficient thickness of low permeability rock to provide a margin of safety above the arrestment interval. At AK Steel, the confining zone consists of the Knox Dolomite. Total thickness of the Knox Dolomite interval is 1,251 feet in the Well No. l. Buffering above the confining zone is provided by the Wells Creek Formation.

A total thickness of 670 feet of Ordovician rocks exists in Well No.1 between the top of the confining zone and the base of the lowermost USDW. This interval consists of various units of shale, carbonate, and siltstone.

2.3 Waste Stream Information

AK Steel injects spent hydrochloric acid (HCl) pickle liquor (SPL) into its two injection wells. SPL is classified as a listed hazardous waste (K062) based on corrosivity and toxicity. The pH of the waste is typically less than 1.0, and the waste stream contains lead and chromium. Because of the geologically favorable conditions present within the AK Steel area of review, AK Steel has been granted approval from USEPA Region V to continue operation of the injection facility.

3.0 FINALTESTING PROGRAM

Plans for a pressure fall-off test, Radioactive Tracer Survey (RAT) and an annulus pressure test and any other testing that may be required by the Director will be submitted to the Ohio EPA for approval in conjunction with the Notice of Intent to Close. These plans will be consistent with the existing permit and applicable regulatory requirements at the time of proposed closure. The pressure fall-off test will be conducted to confirm the pressure decay that has occurred in the injection zone. At a minimum, a Radioactive Tracer Survey and an annulus pressure test will be conducted to ensure mechanical integrity. In addition, a temperature survey, cement bond log, or other test will be run after the tubing is removed from the well to evaluate external casing cement integrity, if required by the Director .

3.1 Pressure Fall-off Test

When the injection facility is to be closed, a pressure fall-off test will be conducted on one of the wells to confirm bottomhole pressure. The wells will be flushed with fresh water to displace any remaining SPL from the wellbores and create a stablized injection period for the fall-off testing. A surface pressure gauge with surface recording equipment will be utilized. After an appropriate fall-off period, kill brine will be displaced to overbalance each well such that there is no positive pressure at the wellheads.

3.2 Mechanical Integrity Testing

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

4.0 PLUG AND ABANDONMENT PLAN

Sections 4.1 and 4.2 outline the proposed plugging and abandonment procedures for the two deep injection wells. Should it become necessary to make significant revisions to the method of closure described in the closure plan, AK Steel 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.

4.1 Plug and Abandon Well 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. Unload approximately 3300 feet of 2-7/8" workstring onto pipe racks.

d. Remove tree and weld on 9-5/8" nipple. Install blow out prevention equipment (BOP).

e. Release tubing seal assembly from Baker Model D 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 3-1/2" Fibercast injection tubing.

g. Run cement bond logs and other logs as needed.

h. Make up cement retainer to set in 9-5/8" 36 lb./ft. casing on 2-7/8" workstring. Tally workstring while running into well. Set cement retainer at 2,840 feet.

i. Mix and pump 250 sacks Class A cement (yield 1.18 cf/sack) down the tubing. Squeeze approximately 210 sacks through retainer until a squeeze pressure of 500 psi is achieved. Unsting from retainer and spot remaining cement. Pull tubing to approximately 2730 feet 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 eight hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 2730 feet. Pressure test casing to 500 psi for 30 minutes.

k. Stage cement in remainder of casing to surface in approximate 500 foot stages using the balanced plug method. An estimated 1010 sacks Class A cement (yield 1.18 cf/sack) will be required to complete the plugging of the 9-5/8" casing.

l. Remove BOP and wellhead equipment. Cut casings off three feet below ground level. Weld an appropriately inscribed 1/2" steel plate on the casing.

m. Rig down and move out pulling unit and equipment.

n. 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 of AK Steel's injection wells are closed at the same time, AK Steel will submit one report for both closures.

4.2 Plug and Abandon Well No. 2

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. Unload approximately 3300 feet of 2-7/8" workstring onto pipe racks.

d. Remove tree and install BOP equipment.

e. Release tubing seal assembly from Baker Model F-1 packer and circulate annular fluid from well with 120 barrels 9.0 lb./gal brine. 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 3-1/2" Fibercast injection tubing.

g. Run cement bond logs and other logs as needed.

h. Make up cement retainer to set in 7" 26 lb./ft. casing on 2-7/8" workstring. Tally workstring while running into well. Set cement retainer at 2850 feet.

i. Mix and pump 215 sacks Class A cement (Yield 1.18 cf/sack) down the tubing. Squeeze approximately 185 sacks through retainer until a squeeze pressure of 500 psi is achieved. Unsting from retainer and spot remaining cement. Pull tubing to approximately 2680 feet 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 eight hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 2680 feet. Pressure test casing to 500 psi for 30 minutes.

k. Stage cement remainder of casing to surface in approximate 500 foot stages using the balanced plug method. An estimated 490 sacks Class A cement (yield 1.18 cf/sack) will be required to complete the plugging of the 7" casing.

l. Remove BOP and wellhead equipment. Cut casings off three feet below ground level. Weld an appropriately inscribed 1/2" steel plate on the casing.

m. Rig down and move out pulling unit and equipment.

n. 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 of AK Steel's injection wells are closed at the same time, AK Steel will submit one report for both closures.

5.0 MATERIALS STANDARDS

This section covers standards and specifications for materials to be used during the closure activities.

- Brine with a minimum density of 9 lb/gal shall be used during closure activities.
- American Petroleum Institute (API) Specifications for Class "A" cement or suitable equivalent shall be used in squeezing the injection intervals and for the closure of each well from the injection interval to the surface.
- Radioactive Iodine (1-131) shall be used for the Radioactive Tracer Survey.

6.0 CLOSURE COST ESTIMATE

The following is an itemized cost estimate for closure of the two AK Steel injection wells effective January 31, 2012.

6.1 Closure Cost Estimate Well No.1

The following is an itemized cost estimate for closure of the two AK Steel injection wells effective January 31, 2012.

1. Prepare location - AK Steel personnel will remove well house, well monitoring equipment and wellhead injection piping		$2,000
2. Pump 250 bl. fresh water down tubing for decontamination		
Truck (1 Day)		4,000
3. Run annulus pressure test (3 1/2" x 9 5/8")		
Pressure Transducer - Recorder		500
4. Run radioactive tracer survey		
Logging Truck	$ 14,000	
Pump Truck	4,000	
		18,000
5. Run pressure fall-off test		
Pump Truck	9,000	
Gauge Rental	2,000	
		11,000
6. Service rig and equipment move-in and rig up (double derrick - four man crew, BOP, mud pump and pit, pipe racks, light plant, crew subsistence, supervisor, stripper head and TIW valve)		14,000
7. Work string - 2.7/8" or 2 3/8" EUE		
Transportation		4,500
8. Mix 230 bl. of 9.0 #/gal. brine water and pump 60 bl. brine water down tubing to kill well		
Workover Rig (1 day)	7,500	
Brine water	4,000	
		11,500
9. Remove tree, install BOP, release tubing seal assembly from Model "D" Baker packer and circulate packer fluid out of annulus with 9.0 #/gal. brine water to assure well is static, four (4) injection packers will be left in well		
Workover Rig (1 Day)	7,500	
Frac Tank (Move-in)	1,000	
Baker	2,000	
3" Pump	500	
		11,000
10. Pull and Jay down tubing		
Workover Rig (l Day)	7,500	

FracTank	200	
		7,700
11. Run cement bond log		
Rig	7,500	
Logs	18,000	
		25,500
12. Go into hole with 2 7/8" work string with 9-5/8" cement retainer and set at 2,840 feet. Pump 210 sacks of Class "A" cement below retainer, unsting from retainer leaving approximately 40 sacks Class "A" cement on top of retainer, pull uphole to 2,500 feet and reverse circulate tubing to clear cement, wait on cement to cure at least 8 hr.		
Workover Rig (1 Day)	7,500	
Cement Retainer	4,500	
Cementer	10,000	
Tubing (1 Day)	2,000	
Frac Tank	200	
		24,200
13. Tag plug and pressure test plug to 500 psi for 30 minutes; circulate brine water out and fresh water in		
Workover Rig (1 Day)	7,500	
Tubing (1 Day)	2,000	
3" Pump	500	
Frac Tank	200	
		10,200
14. Stage load 9 5/8" casing with 175 sacks class "A" cement, pull and lay down 16 joints tubing and repeat process until 9 5/8" casing completely filled, require approximately 1,010 sacks		
Workover Rig (l Day)	7,500	
Cementer	42,000	
Tubing (l Day)	2,000	
Frac Tank	200	
		51,700
15. Remove BOP and wellhead equipment; cut casing off 3 feet below ground level; weil 1/2" plate on casing appropriately fill cellar with cement to ground level		
Workover Rig (1 Day)	7,500	
Welding	1,000	
Readi-mix Cement and delivery	500	
Frac Tank	200	
		9,200
16. Service rig and equipment-rig down and move out		
Workover Rig		10,000
17. Work string		
Transportation and Inspection		7,500
18. Miscellaneous trucking, cleaning, and disposal of brine water		8,000

19. Field supervision (10 Days)		10,800
20. Engineering report preparation		7,000
21. Miscellaneous Contingency on $248,300 (20%)		49,660
(Closure Cost Estimate – Well No. 1)	TOTAL	$ 297,960

6.2 Closure Cost Estimate Well No.2

1. Prepare location - AK Steel personnel will remove well house, well monitoring equipment and wellhead injection piping		$2,000
2. Pump 250 bl. fresh water down tubing for decontamination		
Truck (1 Day)		4,000
3. Run annulus pressure test (3 1/2" x 7")		
Pressure Transducer - Recorder		500
4. Run radioactive tracer survey		
Logging Truck	$ 14,000	
Pump Truck	4,000	
		18,000
5. Service rig and equipment move-in and rig up (double derrick - four man crew, BOP, mud pump and pit, pipe racks, light plant, crew subsistence, supervisor, stripper head and TIW valve)		14,000
6. Work string - 2.7/8" or 2 3/8" EUE		
Transportation		4,500
7. Mix 230 bl. of 9.0 #/gal. brine water and pump 60 bbl. brine water down tubing to kill well		
Workover Rig (1 day)	7,500	
Brine water	4,000	
		11,500
8. Remove tree, install BOP, release tubing seal assembly from Model "F-1" Baker packer and circulate packer fluid out of annulus with 9.0 #/gal. brine water to assure well is static, injection packers will be left in well		
Workover Rig (1 Day)	7,500	
Frac Tank (Move-in)	1,000	
Baker	2,000	
3" Pump	500	
		11,000
9. Pull and lay down tubing		
Workover Rig (l Day)	7,500	
FracTank	200	
		7,700
10 Run cement bond log		
Rig	7,500	
Logs	18,000	

		25,500
11. Go into hole with 2 7/8" work string with 7" cement retainer and set at 2,850 feet. Pump 185 sacks of Class "A" cement below retainer, unsting from retainer leaving approximately 310 sacks Class "A" cement on top of retainer, pull uphole to 2,500 feet and reverse circulate tubing to clear cement, wait on cement to cure at least 8 hr.		
Workover Rig (1 Day)	7,500	
Cement Retainer	4,000	
Cementer	9,500	
Tubing (1 Day)	2,000	
Frac Tank	200	
		23,200
12. Tag plug and pressure test plug to 500 psi for 30 minutes; circulate brine water out and fresh water in		
Workover Rig (1 Day)	7,500	
Tubing (1 Day)	2,000	
3" Pump	500	
Frac Tank	200	
		10,200
13. Stage load 7" casing with 90 sacks Class "A" cement, pull and lay down 17 joints tubing and repeat process until 7" casing completely filled, require approximately 500 sacks		
Workover Rig (I Day)	7,500	
Cementer	30,400	
Tubing (I Day)	2,000	
Frac Tank	200	
		40,100
14. Remove BOP and wellhead equipment; cut casing off 3 feet below ground level; well 1/2" plate on casing appropriately fill cellar with cement to ground level		
Workover Rig (1 Day)	7,500	
Welding	1,000	
Readi-mix Cement	500	
Frac Tank	200	
		9,200
15. Service rig and equipment-rig down and move out		
Workover Rig		10,000
16. Work string		
Transportation and Inspection		7,500
17. Miscellaneous trucking, cleaning, and disposal of brine water		8,000
18. Field supervision (10 Days)		10,800
19. Engineering report preparation		7,000

20. Miscellaneous Contingency on $224,700 (20%)	44,940
(Closure Cost Estimate – Well No. 2)	TOTAL $ 269,640

6.3 Closure Cost Summary

Well No.1 Closure Costs	$ 297,960
Well No.2 Closure Costs	269,640
TOTAL	**$ 567,600**

7.0 FINANCIAL RESPONSIBILITY

Financial assurance information is being submitted to OEPA as required by OAC Rule 3745-34-60.

POST-CLOSURE PLAN
Underground Injection Control Wells No. 1 and No. 2

Prepared for:

AK Steel

AK Steel Corporation
Middletown Works
1801 Crawford Street
Middletown, Ohio 45043-0001

Prepared by:

KEMRON
ENVIRONMENTAL SERVICES

KEMRON Environmental Services, Inc.
2343-A State Route 821
Marietta, OH 45750

and

Petrotek

Petrotek Engineering Corporation
10288 W. Chatfield Ave. #201
Littleton, CO 80127

February 2012

TABLE OF CONTENTS

ATTACHMENTS

1.0 INTRODUCTION

AK Steel Corporation (AK Steel) submits the following plan for post- closure care of the two Class I injection wells operated at the Middletown Works, Butler County, Middletown, Ohio. This plan has previously been submitted by AK Steel and approved by the Ohio Environmental Protection Agency (OEPA) in 1991, 1996, 1997 and 2007 and much of the content was originally developed by Subsurface Technology, Inc. This plan is submitted in accordance with AK Steel's UIC operating permits and Ohio Administrative Code (OAC) Rule 3745-34-61. State and Federal requirements for the Underground Injection Control (UIC) wells are addressed, along with plans for closure of one shallow USDW monitor well.

2.0 RESERVOIR PRESSURE AND WASTE FRONT CALCULATIONS

This section addresses Part I (G) (1) (A) through (D) in AK Steel's permit to operate. The first item addressed is the determination of original pressures in the injection intervals prior to injection of any waste. The second item involves the pressure within the injection interval at the proposed cessation of injection. The third estimates the projected positions of the waste plume front at closure. Lastly, the elapsed time after well closure, at which the cone of influence (COI) no longer contacts the base of the lowermost USDW, is determined. These calculations were prepared utilizing the SWIFT model as submitted by AK Steel to US EPA in August of 2007 to support the Landban Petition Renewal as approved by US EPA in 2008. A summary of the results of the four analyses is provided in Table I.

TABLE I

Summary of Engineering Aspects of Post-Closure Care Plan

Well No.	Original Pressure (psi)	Pressure at Closure Time (psi)	Waste Front Radius (miles)	Elapsed Time (COI = 0) (days)
Well No. 1	1301	1674	0.92	< 1
Well No. 2	1321[1]	1678	0.92	< 1

[1] The Well No. 2 Datum is 41.6 feet below Well No. 1 Datum.
Thus P_o = 1301 psi + 0.433 psi/ft. x 1.12 x 41.6 feet = 1321 psi

2.1 Method

As indicated, the procedure used to generate the pressure and plume projections is from the 2008 UIC Petition modeling (Section VI). In preparing the model, AK Steel's consultants gathered available geological and disposal data to use in modeling. The geological information from well completion reports, well logs, production logs and core data were employed to calibrate the model. Final adjustments were made to the model using the recorded injection rate histories of each well. Once the model was calibrated, predictions of the waste plume configuration and pressure distribution were determined using the maximum projected injection rate for each well.

2.2 Model Parameters

Modeling calibration involves the assignment of geological and physical parameters for the disposal interval in each well. The modeling parameters needed include the injection zone permeability, porosity, depth, original pressure, compressibility, and thickness. These parameters are obtained by analyzing the information from well logs, well tests, production logs and available core data. Table II summarizes the parameters assigned to the injection interval at the Middletown facility. These are the same parameters utilized in the modeling conducted for the 2008 Landban Petition Renewal submitted to the USEPA by AK Steel Corporation for these two injection wells at Middletown, Ohio.

TABLE II
MODELING PARAMETERS

Total Sum of Layer Thickness, h	=	404 ft.
Average Porosity, φ	=	0.1358
Average Permeability, k	=	29.29 md
Average Compressibility, c	=	6.778×10^{-6} psi^{-1}
Injectate Viscosity, μ	=	1.0289 cp

2.3 Original Pressure

Original injection interval pressure is an important parameter in projections and in this instance; the value must be estimated since no measurement of original pressure prior to injection was available. The estimation method was described briefly in Sections 6 and 9 of the 2007 UIC petition document and has historically been reviewed and approved by OEPA and US EPA in prior petition submittals. In addition to evaluation through calculations based on observed fluid measurements and history matching of the SWIFT model, the value was confirmed as generally consistent with available literature historical well tests.

Prior to injection, vertical hydrostatic equilibrium prevailed and this can be used to estimate original injection interval pressure (at the top of the interval). If a linear variation of specific gravity is assumed from the free water level, $Y = 1.0$ at 20 ft. to $Y = 1.015$ at 1040 ft. and a linear variation is also assumed from this point to the top of the injection interval at Well No. 1, $Y = 1.12$ at 2892 ft., then P_o is estimated as:

$$P_o = 0.433 \quad \left[\frac{1.0 + 1.015}{2} (1040 - 20) + \frac{1.015 + 1.12}{2} (2892 - 1040)\right]$$

$$P_o = 1301 \text{ psig}$$

Even though the point at which the rapid increase of specific gravity begins [a depth of 1040 feet (BGL)] is not uniquely determined, this method of pressure estimation has proved reliable in many areas [Amyx (1960)]. This value has been confirmed by extrapolations from shut-in pressure measurements. Since very similar values are obtained using these two methods, the value of P_o must be viewed as probable but subject to some uncertainty.

2.4 Closure Pressure

The closure pressure will vary depending upon the amount of fluid injected. The expected pressure rise adjacent to each wellbore, above the original pressure at the time of well closure, has been calculated for these injection wells using a combination of the actual recorded injection rate history and projected injection rate based on the maximum anticipated injection volume until the well is closed. Various sensitivity analyses were conducted in the most recent UIC Petition renewal that show pressures that could be generated due to various projected conditions. The projected injection zone pressures at closure for each well are given in Table I.

2.5 Elapsed Closure Time

After a well is closed, the pressure will begin to decline. Hence the cone of influence (COI) of the well also decreases. As required by permit conditions, an estimate was made of the elapsed time from well closure until the COI no longer meets the base of the lowermost USDW using the SWIFT model runs of 2007. The post-closure pressure declines are based on future injection rates of 30 gpm each for both Wells No.1 and No. 2. The elapsed time after closure for the COI to no longer intersect the base of the lowermost USDW is less than one day after injection ceases for both wells. Values are listed in Table I.

2.6 Waste Plume Configuration

The waste front projections presented in the 2008 Landban Petition Renewal approval were based upon the leading edge of the plume including dispersion at a concentration reduction ratio of $1x10^{-6}$ limit for any constituent concentration. The maximum radii of the health-based limit plume boundaries over the operational lifetime are listed in Table I, and extend approximately 0.92 miles from either well.

3.0 POST-CLOSURE CORRECTIVE ACTION

Part I(G)(2) of the UIC permits require AK Steel to continue and complete any corrective action required under OAC Rule 3745-34-30. No corrective action has been or is projected to be required at the AK Steel injection facility. Section 9 of AK Steel's 2008 UIC Landban Exemption Petition as approved demonstrates that no injected material will migrate from the injection zone due to vertical migration or molecular diffusion.

In addition, Section 6 of the 2007 UIC Petition document discusses the fact that no artificial penetrations, with the exception of the AK Steel injection wells, penetrate the top of the confining zone within the AK Steel Area of Review (AOR). Since no wells other than the injection wells penetrate the confining zone within the AOR, no remedial action is required.

4.0 POST-CLOSURE CARE REQUIREMENTS

The following sections address the requirements set forth in Part I (G) (3) through (7) of AK Steel's UIC permits.

4.1 Post-Closure Monitoring

Under Part I (G) (3) of the permit to operate and OAC Rule 3745-34-61, AK Steel is required to maintain and monitor any ground water monitoring wells required under the UIC Class I permits until pressure in the injection zone decays to the point that the well's COI no longer intersects the potentiometric surface of the lowermost USDW. The projected post-closure pressure decline to a COI that no longer intersects the potentiometric surface of the USDW is calculated to take less than one day based on worst case projections. This can be confirmed by review of annual fall-off testing, wherein pressure measured in the well at datum depth typically drops below the calculated critical pressure within hours of shut-in. The USDW-01 shallow ground water monitor well will continue to be monitored for a minimum of six months after injection has ceased. This will ensure that monitoring data is collected longer than any cone of influence (zone of endangering influence) can exist. Should data collected during Class I injection well operations, and/or under closure and post-closure requirements for the Class I injection wells, indicate that an extended schedule for monitoring of well USDW-01 is required to meet the regulatory standard of OAC Rule 3745-34-61(G), the Director may extend the USDW monitoring period upon a finding that the well may endanger a USDW.

4.2 Submission of Survey Plat

Upon closure of the injection facility, AK Steel will survey and prepare a survey plat which indicates the location of the two injection wells relative to permanently surveyed benchmarks. Copies of this plat will be submitted to the Administrator of USEPA - Region V, the Director of OEPA, and the local zoning authority.

4.3 Notification of State and Local Authorities

AK Steel will provide notification of closure to the Ohio Department of Natural Resources (ODNR) Division of Oil and Gas Resources Management, and the Butler County Health Department. Included with the notification will be information regarding the chemical nature of the injected waste stream, delineation of the projected 10,000 year waste plume, identification of the depths of the injection and confining zones, well schematic, and plugging records. This information will be used by State and local authorities to impose appropriate conditions upon subsequent drilling activities that may penetrate the facility's confining or injection zone.

4.4 Record Retention

AK Steel will retain records accumulated over the operating lifetime of the injection wells reflecting the nature, composition and volume of all injected fluids for a period of three (3) years following closure of the injection wells. At the end of the retention period, AK Steel will deliver these records to the Director of OEPA.

4.5 Deed Notation

Upon closure, AK Steel will have a notation placed on the deed to the facility property or some other instrument which is normally examined during title search. This notation will in perpetuity provide any potential purchaser of the property with the following information:

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

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

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

5.0 ESTIMATE OF COST OF POST-CLOSURE CARE

The following is a summary of the post-closure care requirements and associated estimated costs as of January 31, 2012

a. Plug and abandon USDW monitor well	$ 12,500
b. Take final water samples from USDW monitor well and run chemical analyses.	10,000
c. Prepare and submit survey plat.	3,000
d. Notify State and local authorities of closure and provide required information.	2,500
e. Retain required records for a minimum of three years; transfer to OEPA if records no longer being retained by AK Steel.	1,500
f. Notate deed or other appropriate document.	2,500
g. Final modeling of injectate plume and pressure front (post-closure modeling).	20,000
Total cost for post-closure care (including one shallow USDW monitoring well)	**$ 52,000**

ATTACHMENT A

PLUGGING AND ABANDONMENT PROCEDURE
AK STEEL USDW MONITORING WELL

ATTACHMENT A
PLUG AND ABANDONMENT PROCEDURE - AK STEEL USDW MONITOR WELL

1. Remove protective covers or pilings.
2. Remove well sampling equipment.
3. Check for fill.
4. Run tremie pipe to top off fill.
5. Circulate hole with cement from fill to surface.
6. Remove tremie pipe.
7. Verify cement top.
8. Report plugging activities to the ODNR and the OEPA.

AK Steel Corporation

March 28, 2012

Mr. Shawn Sellers
Compliance Assurance Section
Division of Hazardous Waste Management
Ohio EPA
Lazarus Government Center
50 West Town Street, Suite 700
Columbus, OH 43215

Sincerely,

AK STEEL CORPORATION

Kathy H. Lewis

Kathy H. Lewis, CRM, CIC
Risk Manager

KHL:khl
Enclosures

Cc: Albert E. Ferrara, Jr. (w/o enclosures)
David Miracle (w/enclosures)
Pat Gallo (w/enclosures)
Katie Laing-Kistler (w/enclosures)

Mr. Jess Stottsberry (w/enclosures)
UIC Unit Geologist
Division of Drinking and Ground Waters
Ohio EPA
Lazarus Government Center
50 West Town Street, Suite 700
Columbus, OH 43215

AK Steel Corporation
9227 Centre Pointe Drive
West Chester, Ohio 45069

Phone 513.425.2888
Fax 513.425.5815

Albert E. Ferrara, Jr.
Senior Vice President
Of Finance And
Chief Financial Officer

March 28, 2012

Director
Ohio Environmental Protection Agency
Lazarus Government Center
50 West Town Street, Suite 700
Columbus, OH 43215

Re: Letter from chief financial officer to demonstrate liability coverage

Dear Director:

I am the Chief Financial Officer of AK Steel Corporation, 9227 Centre Pointe Drive, West Chester, Ohio 45069. This letter is in support of the use of the financial test to demonstrate financial responsibility for liability coverage as specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code.

The firm identified above is the owner or operator of the following facilities for which liability coverage for both sudden and nonsudden accidental occurrences is being demonstrated through the financial test specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code:

Facility	EPA ID#	Mailing Address
Middletown Works	OHEPA 05-09-0062 USEPA OHD004234480	1801 Crawford St. Middletown, OH 45043

The firm identified above guarantees, through the guarantee specified in rules 3745-55-40 through 3745-55-51 and 3745-66-40 through 3745-66-48 of the Administrative Code, liability coverage for both sudden and nonsudden accidental occurrences at the following facilities owned or operated by the following:

Facility	EPA ID#	Mailing Address
	NONE	

The firm identified above is:

(1) the direct or higher-tier parent corporation of the owner or operator;

NOT APPLICABLE

(2) owned by the same parent corporation as the parent corporation of the owner or operator, and receiving the following value in consideraiton of this guarantee; or

NOT APPLICABLE

(3) engaged in the following substantial business relationship with the owner or operator, and receiving the following value in consideration of this guarantee.

NOT APPLICABLE

1. The firm identified above owns or operates the following facilities for which financial assurance for closure or post-closure care or liability coverage is demonstrated through the financial test specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code. The current closure and/or post-closure cost estimate covered by the test are shown for each facility:

NONE

2. The firm identified above guarantees, through the guarantee specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code, the closure and post-closure care or liability coverage of the following facilities owned or operated by the guaranteed party. The current cost estimates for the closure or post-closure care so guaranteed are shown for each facility:

NONE

3. The firm identified above is demonstrating financial assurance for the closure or post-closure care of the following facilities through the use of a test equivalent or substantially equivalent to the financial test specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code. The current closure and/or post-closure cost estimates covered by such a test are shown for each facility:

NONE

4. The firm identified above owns or operates the following hazardous waste management facilities for which financial assurance for closure or, if a disposal facility, post-closure care, is not demonstrated to the director through the financial test or any other financial assurance

mechanisms specified in rules 3745-55-40 to 3745-55-51 and 3745-66-40 to 3745-66-48 of the Administrative Code. The current closure and/or post-closure cost estimates not covered by such financial assurance are shown for each facility:

NONE

5. This firm is the owner or operator of the following UIC facilities for which financial assurance for plugging and abandonment is required under Chapter 3745-34 of the Administrative Code and is assured through a financial test. The current closure cost estimates as required by Chapters 3745-34, 3745-55, and 3745-66 of the Administrative Code are shown for each facility:

NONE

This firm is required to file a Form 10-K with the securities and exchange commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on December 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31, 2011.

Part A. Liability Coverage for Accidental Occurrences

ALTERNATIVE 1

1.	Amount of annual aggregate liability coverage to be demonstrated:	$ 8,000,000
*2.	Current assets:	$ 1,274,409,190
*3.	Current liabilities:	$ 1,137,121,150
4.	Net working capital (line 2 minus line 3):	$ 137,288,040
*5.	Tangible net worth:	$ 812,257,131
*6.	If less than 90% of assets are located in the U.S., give total U.S. assets	$ N/A

	YES	NO
7. Is line 5 at least $10 million?	X	
8. Is line 4 at least 6 times line 1?	X	
9. Is line 5 at least 6 times line 1?	X	
*10. Are at least 90% of assets located in the U.S.? If not, complete line 11.	X	
11. Is line 6 at least 6 times line 1?	N/A	

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

Sincerely,

Albert E. Ferrara, Jr.
Senior Vice President of Finance and Chief Financial Officer
March 28, 2012

AEF:khl
OH EPA/Fin. Resp.

Addendum to Attachment A

RE: Calculation of Tangible Net Worth

Under AK Steel Corporation's (the "Company") method of accounting for its pension and other postretirement benefit ("OPEB") plans, the company recognizes into its results of operations, as a fourth quarter non-cash "corridor" adjustment, any unrecognized actuarial net gains or losses that exceed 10% of the larger of projected benefit obligations or plan assets. This method of accounting was adopted in conjunction with the Company's acquisition of Armco Inc. in 1999, and it is the Company's understanding that prior to 2010 AK Steel Corporation was the only company in the Fortune 500 that used this method of accounting. A few other Fortune 500 Companies adopted a similar method in 2010. The more common method of accounting, which is unavailable to the Company, would amortize these "corridor charges" into results of operations, and thereby reduce Tangible Net Worth, over a longer time period, most likely in the range of 10 – 15 years.

The Company's method of accounting has resulted in the recognition of cumulative after-tax corridor charges and the resultant reduction of Tangible Net Worth in 2011 due primarily to declining interest rates and lower than expected asset returns over the eleven-year period of 2001 – 2011. The 2011 Tangible Net Worth for the Company was $812,257,131 as detailed per Attachment A. It should be noted that the above mentioned corridor charges were non-cash, and, therefore, did not impact the Company's cash or liquidity position.

As detailed on Attachment A, the Company's calculation adds back the cumulative corridor charges of $1,640,479,884 to Tangible Net Worth and amortizes the amounts over a period of ten years as a reduction of Tangible Net Worth. It is the Company's opinion that this methodology presents a more appropriate and comparable level of Tangible Net Worth for purposes of the financial test. Also, the Company's bank agreement permits similar treatment for calculation of certain financial covenants.

Attachment A
Calculation of Tangible Net Worth - 2011

		2010	
Tangible Net Worth Before Adjustments		$320,856,982	
Adjustments: (See calculations below)			
Plus:	Cumulative After-Tax Corridor Charges	$1,640,479,664	(A)
Less:	Amortization of Cumulative After-Tax Corridor Charges	($1,148,778,735)	(B)
Tangible Net Worth per Line 5		$812,557,131	

	Corridor Charges		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011		Cumulative Amortization
2001	$121,070,529		$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053	$12,107,053			$121,070,529
2002	$483,814,594			$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459	$48,381,459		$483,814,594
2003	$146,288,651				$14,628,666	$14,628,666	$14,628,666	$14,628,666	$14,628,666	$14,628,666	$14,628,666	$14,628,666	$14,628,666		$130,759,799
2004	$200,132,154					$20,013,215	$20,013,215	$20,013,215	$20,013,215	$20,013,215	$20,013,215	$20,013,215	$20,013,215		$160,105,723
2005	$33,719,564						$3,371,956	$3,371,956	$3,371,956	$3,371,956	$3,371,956	$3,371,956	$3,371,956		$23,603,695
2006	$83,107,103							$8,310,710	$8,310,710	$8,310,710	$8,310,710	$8,310,710	$8,310,710		$49,864,262
2008	$407,418,056									$40,741,806	$40,741,806	$40,741,806	$40,741,806		$162,967,223
2011	$165,929,231												$16,592,923		$16,592,923
Cumulative	$1,640,479,664	(A)	$12,107,053	$60,488,512	$75,017,377	$95,030,593	$98,402,549	$106,713,260	$106,713,260	$147,455,066	$147,455,066	$147,455,066	$151,940,935	(B)	$1,148,778,795

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
AK Steel Holding Corporation
West Chester, Ohio

We have audited the accompanying consolidated balance sheets of AK Steel Holding Corporation and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the accompanying consolidated financial statements, the Company has changed its method of presenting comprehensive income in 2011, due to the adoption of Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control–Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Cincinnati, Ohio
February 27, 2012

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON APPLYING AGREED-UPON PROCEDURES

To the Board of Directors
AK Steel Holding Corporation
West Chester, Ohio

We have performed the procedures included in the Ohio Administrative Code, Rule 3745-55-47(F)(3)(c) (the "Regulations"),which were agreed to by the Ohio Environmental Protection Agency (the "OEPA") and AK Steel Holding Corporation (the "Company"), solely to assist the specified parties in evaluating the Company's compliance with the financial test option as of December 31, 2011, included in the accompanying letter dated March 28, 2012 related to the facility at Middletown Works (OHEPA 05-09-0062 and USEPA OHD004234480), from Albert E. Ferrara, Jr., Senior Vice President of Finance and Chief Financial Officer of the Company. Management is responsible for the Company's compliance with those requirements. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of the parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

We have been informed that, under the Company's interpretation of the financial test option contained in the OEPA Regulations, when two methods of adoption of a new accounting standard are permissible under accounting principles generally accepted in the United States of America, a company may select a different method of adoption of the new accounting principle for the financial test option from the method used to prepare the company's financial statements, as the OEPA Regulations do not specifically prohibit such treatment. Accordingly, the Company selected the minimum amortization method of recognizing actuarial net gains and losses that exceed ten percent of the greater of the projected benefit obligation or plan assets (defined as the "corridor") pursuant to Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715, *Compensation — Retirement Benefits* ("ASC 715"), for the purpose of the financial test option; whereas for its financial statement purposes, the Company immediately recognized actuarial net gains and losses that exceeded the corridor. Either method of adoption is allowable under ASC 715.

The procedures that we performed and related findings are as follows:

1. We compared the amounts included in items 2 and 3 under the caption Alternative I in the letter referred to above with the corresponding amounts in the audited consolidated financial statements of the Company as of and for the year ended December 31, 2011, on which we have issued our report dated February 27, 2012, which includes an explanatory paragraph regarding the Company's adoption of Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*, and noted that such amounts, when adjusted for rounding, were in agreement.

2. We recomputed, from the consolidated financial statements referred to in procedure 1, tangible net worth as defined in the OEPA Regulations and compared such amount to the amount included in item 5 under the caption Alternative I in the letter referred to above. The amount in item 5 is $491,701,149 greater than the recomputed amount as a result of the Company's interpretation for the application of an accounting pronouncement described in the second paragraph.

3. We recomputed, from the consolidated financial statements referred to in procedure 1, the information included in items 4, 6 and 10 under the caption Alternative I in the letter referred to above and noted no differences.

We were not engaged to, and did not, perform an examination, the objective of which would be the expression of an opinion on the accompanying letter dated March 28, 2012. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the board of directors and management of the Company and the OEPA and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 28, 2012

TRUST AGREEMENT
Dated July 9, 2004

SCHEDULE A

IDENTIFICATION OF FACILITIES AND COST ESTIMATE

U.S. EPA ID#: OHD 004234480
OHEPA ID#: 05-09-0062

Facility	Ohio Permit #	Closure Cost	Post-Closure Cost
Middletown Works 1801 Crawford St. Middletown, OH 45043	UIC 05-09-001-PTO-I UIC-05-09-002-PTO-I	$ 567,600	$ 52,000
Total Cost (Revised February, 2012)		$ 567,600	$ 52,000

Ohio | Environmental Protection Agency
John R. Kasich, Governor
Mary Taylor, Lt. Governor
Scott J. Nally, Director

July 12, 2012

Ms. Kathy H. Lewis, CRM
Risk Manager
AK Steel Corporation
9227 Centre Pointe Drive
West Chester, Ohio 45069

RE: **AK Steel Corporation – Middletown, Ohio**
Financial Record Review
OHD 004 234 480

Dear Ms. Lewis:

On July 11, 2012, I conducted a financial record review of the AK Steel Corporation – Middletown, Ohio (AK Steel) facility. I evaluated the facility for compliance with the closure and post-closure care financial assurance, closure and post-closure cost estimates and liability requirements as set forth in Ohio Administrative Code (OAC) rules 3745-55-42 through 3745-55-47. Jess Stottsberry of Ohio EPA's Division of Drinking and Groundwater evaluated the Underground Injection Control cost estimate. [OAC rules 3745-34-36(D)(1)(c) and 3745-34-62]

To demonstrate financial assurance for closure and post-closure care, a trust agreement is used. The standby trust agreement was entered into July 9, 2004 by and between AK Steel and The Bank of New York Trust Company, N.A. (BNY) The Most recent statement of balance, provided by BNY, showed a current balance of $619,600.00 on May 31, 2012. On March 28, 2012, Ohio EPA received cost estimates prepared by KEMRON Environmental Services, Inc. and Petrotek Engineering Corporation and dated February 2012. The closure cost estimate was revised to a total of $567,600 and the post-closure cost estimate was revised to a total of $52,000.

To demonstrate third party liability coverage, a Financial Test was included and signed by the Chief Financial Officer. The Financial Test satisfies the third-party liability requirements for both sudden and non-sudden accidental occurrences. The limits of liability are $4,000,000 per occurrence and $8,000,000 in the aggregate.

Based upon review of the documentation noted above, AK Steel is in compliance with Ohio's financial assurance requirements.

If you have any questions, please feel free to call me at (614) 644-2933 or email me at shawn.sellers@epa.ohio.gov.

Sincerely,

Shawn M. Sellers

Shawn M. Sellers, P.E.
Engineering, Remediation, and Authorizations Section
Division of Materials and Waste Management

SMS/jm

ec: Jess Stottsberry, UIC Unit Geologist, DDAGW

Notice:
Ohio EPA's failure to list specific deficiencies or violations in this letter does not relieve your company from having to comply with applicable regulations.

ATTACHMENT B

GEO-TECHNICAL INFORMATION

I. Geology Description - Overlying, Underlying Units, Injection Interval, Arrestment Interval, and Confining Zone

II. Core Testing Results - Warren County Core

III. Seismic - Discussion

6.0 GEOLOGY

Minimum siting criteria for Class I hazardous injection wells are specified in 40 CFR § 146.62, Subpart G and have been included by reference in OEPA Class I rules (OAC Rule 3745-34-51). The siting criteria require the demonstration of the geologic suitability of a site through analysis of the geologic structure, stratigraphy, and seismicity. The minimum siting criteria also require the analysis of the hydrogeology of a site. Section 6.0 of this repermit application provides information which demonstrates the geologic suitability of the AK Steel Middletown facility. Hydrogeologic and aquifer hydrodynamic information is included in Sections 7.0, 9.0, and 10.0 of this application. A detailed discussion of the local, regional, and well site lithology and stratigraphy; regional structure; and regional seismicity along with supporting maps and figures can be found in Volume II, Section III of the AK Steel 2006 UIC Petition document and subsequent updates submitted in 2007 (Subsurface, 2006, 2007). Section 6.0 of this repermit application document reproduces a significant portion of this USEPA approved UIC petition material and also presents updated material regarding the geology underlying the AK Steel Middletown facility.

Drawing 2 is a stratigraphic column of AK Steel UIC No.1. Drawing 2 illustrates the vertical extent of the injection interval, arrestment interval, injection zone, confining zone, and location of the lowermost Underground Source of Drinking Water (USDW) at the AK Steel injection well facility. Drawings 3 and 4 are north-south and east-west regional cross sections which demonstrate the regional lateral continuity of arrestment and confining strata.

The injection zone consists of the injection interval and the arrestment interval. The arrestment interval is the upper portion of the injection zone which prevents the upward movement of injected waste. The injection interval is the portion of the injection zone into which waste is directly emplaced. The injection interval at AK Steel consists of the lower 79 feet of the Cambrian Eau Claire Formation, the entire Mt. Simon Sandstone, and the upper 60 feet of the Middle Run Formation. The injection interval, 396 feet thick in UIC Well No. 1, is composed of sandstone.. The properties of the injection interval are discussed in detail in Sections 6.1.2 and 6.2.4.2 of this document.

The arrestment interval at the AK Steel Middletown Works site consists of the upper 477 feet of the Eau Claire Formation as measured in UIC Well No. 1. The properties of the arrestment interval are discussed in Sections 6.1.2 and 6.2.4.3 of this document.

The upper confining zone consists of the Knox Dolomite. Total thickness of the Knox Dolomite is 1251 feet in UIC Well No. 1. Buffering above the upper confining zone is provided by the Wells Creek Formation. The properties of the Knox and Wells Creek are described in Sections 6.1.2 and 6.2.4.4 of this document.

A total thickness of approximately 650 feet of Ordovician rocks exist in UIC Well No. 1 between the top of the confining zone and the base of the lowermost USDW. This interval consists of various units of shale, carbonate, and siltstone. Properties of the geologic units in this interval are presented in Sections 6.1.2 and 6.2.4.5 of this document.

Lower confinement is provided by the tight, lithic arenite of Middle Run Formation. This unit is described in detail in Sections 6.1.2 and 6.2.4.1.

Depositional environments during the Paleozoic Era in the region of AK Steel Middletown Works were suitable for the deposition of laterally continuous sedimentary units, as described in Section 6.1.1 of this document. In addition, the regional cross sections (Drawings 3 and 4) demonstrate the continuity of formations and illustrate the gentle dip of the strata across the region.

Construction of detailed subsurface maps, especially detailed local structure maps, in the vicinity of AK Steel was not possible because of the limited subsurface control available in this area. As stated in the 2002 permit reapplication and confirmed in 2011, of the wells drilled to a depth greater than 1000 feet in Butler, Warren, Montgomery, and Preble Counties, borehole geophysical logs are available for only ten wells, including the two AK Steel disposal wells. Further only eight sub-Knox wells occur in this four county area (Baranoski, 2004). For these reasons, the discussion of geologic structure is based upon published regional maps and reports covering this area.

Seismic activity within 100 miles of the AK Steel site is addressed in Section 6.3 of this document.

The stratigraphic nomenclature used throughout this report follows that established by and published by the ODNR's, DGS (e.g. Figure 6.0-1, Table 6.2.3-I).

The geology of the site and region, as documented here and in the USEPA approved UIC Petition (Subsurface, 2006, 2007) is suitable for injection and containment of the permitted wastestream. The waste remains contained and the geologic conditions provide long term containment to prevent a release outside the permitted interval.

6.1 Regional Geology

The following sections discuss the regional geologic setting in the vicinity of AK Steel and is presented to demonstrate the continuity and physical properties of critical geologic units.

6.1.1 Regional Geologic History

During the Middle Proterozoic of the Precambrian Era, felsic volcanic and plutonic igneous rocks were emplaced in western Ohio. These rocks have been radiometrically dated at approximately 1.5 billion years and comprise the units of the Granite-Rhyolite Province (also known as the Central Province).

A major rifting event occurred approximately 1.1 billion years ago during Keweenawan time (Dickas et al., 1992), in what is now the central region of the United States and Canada. This rifting resulted in the formation of a series of related rifts that are collectively referred to as the Midcontinent Rift System (MRS). The MRS extends from Kansas northeastward through Nebraska, Iowa, the Lake Superior region, and southward through the Lower Peninsula of Michigan and possibly into Ohio and Kentucky.

The Cincinnati Arch Consortium report entitled "The Geology and Geophysics of the East Continent Rift Basin" (Wickstrom, Drahoval, and Keith, 1995) reports the results of a study conducted to characterize the pre-Mt. Simon basin discovered during the coring of DGS 2627 that was continuously cored from 1987 to 1989. Evidence from this study indicates that this basin, referred to as the East Continent Rift Basin (ECRB), is a southern extension of the Mid Continent Rift System that exists farther to the north and west. More detailed information about the ECRB is presented in Section 6.1.2 - Regional Stratigraphy and Section 6.1.3 - Regional Structure where the relationship between the ECRB and the Middle Run Formation is discussed.

By the end of the Precambrian Era, Ohio was the site of continental-continental convergent plate margin activity. This activity which occurred between approximately 1.2 billion years and 950 million years ago precipitated the Grenville Orogeny. The western structural boundary of these Precambrian mountains is known as the Grenville Front. Precambrian rocks to the west of this boundary consist of unmetamorphosed felsic igneous and metasedimentary rocks of the Granite-Rhyolite Province. Precambrian rocks of the Grenville Province lie to the east of this boundary and consist of metamorphic rock. The thrusting and metamorphism related to the Grenville Orogeny occurred approximately 1.06 to 1.03 billion years ago (Dickas et al., 1992). In Late Precambrian time, uplift and erosion occurred.

Convergent plate margin activity continued to influence the rock record of Ohio during the Paleozoic Era, but this activity was centered farther to the east relative to the collisional activity associated with the Grenville Orogeny. Ohio was located close to the Paleoequator during much of the Paleozoic Era in a relative position similar to Brazil today (Schumacher, 1991). A volcanic island arc was southeast of Ohio during the Paleozoic which supplied volcanic and other terrigenous clastic material to the seas northwest of that arc.

Evidence of the high level of volcanism occurring in this island arc system is provided by the multiple bentonite beds (altered volcanic ash) in the Paleozoic stratigraphic section of Ohio (Schumacher, 1991). Paleo trade winds blowing from the southeast towards the northwest deposited volcanic ash into the area of present day Ohio. Two episodes of intense volcanism are recorded in Middle Ordovician-age strata. The first episode resulted in the deposition of the extensive Deike and Millbrig bentonites. These layers have been traced from the Mississippi River eastward through eastern North America, Europe, and the eastern portion of the former Soviet Union. The volumes of ash generated during these eruptions has been estimated at approximately 5000 times that of the eruption of Mount St. Helens in 1980. A second episode of intense volcanism occurred 5 to 10 million years later and resulted in the deposition of seven additional bentonite beds in Ohio. The lower four beds are known as the Westboro bentonite zone and the upper three as the Bear Creek bentonite zone. Continuing volcanism in the Devonian Period resulted in the deposition of bentonite beds of similar distribution during the Middle Devonian.

Early Cambrian time saw a continued erosion of the land mass. The seas began a slow transgression from the east. Large quantities of clastics and some carbonates were deposited in the Paleozoic Appalachian Basin. As the sea continued to encroach upon the land, dolomite and limestone were being deposited in deeper waters, while deposition of clastics was limited to near shore areas being fed by major drainage systems (Freeman, 1953). There was an uplifting of the Canadian shield near the end of Cambrian time, tilting the sediments of the area.

As the Cambrian Period ended and the Ordovician Period began, much of the land mass was covered by the sea. During the Ordovician Period, marine regression occurred exposing newly deposited sediments to erosion for the first time, resulting in the Middle Ordovician Knox unconformity. Another period of transgression began, resulting in a repeat of Cambrian history with one notable exception: Erosion of fresh sediments covering the land mass was occurring rather than erosion of igneous and metamorphic rocks of the Precambrian crust. Consequently, the lithology of these new deposits reflected the lithologies of the nearest source areas

(Freeman, 1953). A series of transgressing and regressing shallow seas, associated with periods of broad, gentle uplifting of the uplands and continued subsidence in the basins dominated the remainder of Ordovician time.

By early to mid-Silurian time, western Ohio was close to wave-base, while the basins to the west, north, and east were receiving a large amount of sediments (Janssens, 1967). During early Devonian Period, the seas retreated and uplifting occurred, followed by extensive erosion. The seas returned, depositing Devonian-Mississippian shales across the region.

Subsidence and uplift continued well into the Pennsylvanian Period. Movement became slower and more episodic from Late Pennsylvanian until the close of the Paleozoic Era. Erosion or non-deposition prevailed throughout the Mesozoic Era and into the Cenozoic Era. During the Pleistocene Epoch, the region was exposed to Illinoisan and Wisconsin glaciation (Figure 6.1.1-1). Post-glacial streams have deposited up to 400 feet of valley fill along stretches of the major river systems.

6.1.2 Regional Stratigraphy

The Precambrian basement of the Granite-Rhyolite Province (Central Province) consists of high grade metamorphic and igneous rocks. Typical lithologies include granites, rhyolite, trachylite, and quartzite. The Grenville Front, which runs north-south through west-central Ohio, is the structural boundary that separates the Granite-Rhyolite Province from the Grenville Province (Figure 6.1.2-1). The Grenville Province consists of highly folded, intruded, medium to high grade metamorphic rock that include schist, amphibolite, and gneiss.

Middle Run

Seismic reflection surveys conducted in several locations in western Ohio (e.g. Richard and Wolfe, 1995; Shrake et al., 1990; Baranoski et al., 2009; Wolf et al., 1993; Dean et al., 2002a and 2002b) indicate the presence of a thick sequence of pre-Mt. Simon stratified units consisting of clastic sedimentary layers and possibly layered volcanics. The topmost unit of this sequence in Western Ohio is the Middle Run Formation. That was first recognized as a new formation in the ODNR, DGS Core Hole No. DGS 2627 located in Warren County approximately 12 miles northeast of the AK Steel site. The type section for the Middle Run Formation is designated as the basal 1910 feet of DGS 2627 (Shrake, 1991; Shrake, 1990). The lithologic description of this section indicates that the Middle Run is a tightly compacted, fine to medium-grained, subrounded to subangular, reddish lithic arenite (sandstone) with lithic clasts composed of (in the order of increasing abundance) volcanic, metamorphic, plutonic, and sedimentary fragments. An 80-foot siltstone was also identified in the type section (Dickas et al., 1992). The contact between the Middle Run and the overlying Mt. Simon Sandstone is sharp where penetrated and cored in DGS 2627. Based on the 8 mile seismic line centered on DGS 2627, the depth to the base of the Middle Run was estimated to be about 7000 feet below the surface or 1620 feet deeper than the total depth (5380 feet) of the well.

Both the sandstone and the siltstone elements of the Middle Run at DGS 2627 were reported to have no identifiable porosity (Shrake et al., 1990). A thin section analysis of the Middle Run indicated an intergranular porosity of ~0.5% (Shrake et al., 1991). Wolfe et al. (1993) in describing the petrology of the Middle Run state that "[p]orosity is almost totally absent where we have observed it in cuttings and cores, and hence we hold little hope that the Middle Run sandstone itself could ever be a petroleum reservoir or a site for liquid waste disposal."

Lithologic, seismic, gravity, and magnetic data indicates that the Middle Run Formation was deposited in a rift-associated sedimentary basin during Late Precambrian time (e.g. Shrake et al., 1991; Shrake, 1991; Drahovzal et al., 1992; Dickas et al., 1992; Lucius and von Frese, 1988). Lithologic similarities with other red clastic sequences associated with the Precambrian MRS in Michigan and Wisconsin support the interpretation that the Middle Run is related to a rift basin. In addition to lithologic similarities, the seismic, magnetic, and gravity data suggest a genetic relationship between the MRS and the rift basin containing the Middle Run. This relationship further supports Late Precambrian age assigned to the Middle Run. Early investigators (e.g. Wolfe et al., 1993; Richard and Wolfe, 1995) suggested a younger Eocambrian or Early Cambrian age for the Middle Run and associated basin. Baranoski et al., 2009 pointed out that age dating of detrital zircon in the Middle Run in the East Continental Rift System of Ohio (Santos et al., 2002) supports deposition of Middle Run sediments at the end of the Grenville Orogeny; Baranoski et al. also show that the Middle Run was deposited in association with and following deposition of East Continent Rift System fill sequences, and may also have occurred in association with later foreland basin development (see Table 3 and Figures 4 and 5 in Baranoski et al., 2009). In short, recent work support a complex history associated with pre-Mt.Simon sedimentation that includes multiple sequences of sedimentary units culminating in the deposition of Middle Run-Foreland Basin sediment deposition followed by erosion prior to deposition of the Mt.Simon Formation. The structure is also discussed in Section 6.1.3.

Mt. Simon

The Cambrian-Ordovician Sauk sequence unconformably overlies the Middle Run Formation at the AK Steel site. The Sauk includes the Mt. Simon Sandstone, the Eau Claire Formation, and the Knox Dolomite.

The Mt. Simon is a thick sandstone present in several states including Michigan, Indiana, western Kentucky, and western Ohio (Baranoski, 2007). It is stratigraphically continuous in the AK Steel area and is approximately 300 feet thick in Butler County, thinning to less than 100 feet thick in Green and Clinton Counties to the east (Figure 6.1.2.2).

The Mt. Simon is a clear, very bright red to yellowish orange, or white, fine to coarse grained, poorly sorted, friable, hematinic, feldspathic quartzose sandstone. The sands generally consist of equal portions of quartz and feldspar. Isolated sandstone beds within the formations can be well-sorted and extremely permeable. Over the past decade, the Mt. Simon has been the target of numerous studies to evaluate its potential for carbon dioxide sequestration; as a result, the geology of the Mt. Simon has been extensively studied in sequestration target areas in Michigan, Ohio, and Kentucky (e.g. Medina et al., 2010, Wickstrom et al., 2005, Barnes, et al., 2009, MRCSP 2005, 2011). These studies verify the presence of the Mt. Simon throughout southern Ohio, although the unit is typically much thinner in southern Ohio and occurs at much shallower depths than in other locations in the Michigan and Illinois Basins. Barnes et al. (2009) indicate that the Mt. Simon in southeastern Michigan is composed of three basic units: a basal, arkosic unit, a middle quartz arenite-glauconite unit, and an upper shale-rich unit that grades conformably into the Eau Claire Formation. A lower and upper unit was identified by Baranoski (2007) in Ohio, and the description of this upper unit is generally consistent with the middle unit of Barnes et al. (2009). Recent studies (Baranoski, 2007) indicate that the Mt. Simon may be limited to the western part of Ohio, but is continuous within the AK Steel areas and western Ohio as a whole.

Near AK Steel Middletown Works, the lower Mt. Simon is conglomeritic and arkosic. It grades upwards into a sandstone or sandy dolomite. Thin green and red shale streaks parallel very porous and permeable red sands just above the base.

The middle/upper Mt. Simon contains medium to coarse-grained, poorly sorted, round to angular, frosted, poorly consolidated sandstone. Minor amounts of silica or carbonate cement with possible feldspar growth have been reported. Dolomite and hematite may act as additional cement. It becomes increasingly calcareous towards the top and contains a few marine fossils. Some siltstone layers and thin shales are present in the upper zone. Glauconite is only present where the Eau Claire overlies the Mt. Simon in western Ohio (Janssens, 1973).

Eau Claire

The Eau Claire Formation overlies the Mt. Simon at the AK Steel site. This formation consists of interbedded glauconitic sandstones, siltstones, shales, and dolomite. Siltstones and sandstones are light to medium greenish-gray, brown, or very light orange. Interbedded green and reddish-brown glauconitic shales are more prevalent near the top of the formation. Limestone may occur in trace amounts (Janssens, 1973). The contact of the Eau Claire with the Mt. Simon is transitional with the base of the Eau Claire being a glauconitic siltstone and very fine-grained sandstone.

The Eau Claire undergoes a facies change to the east where it becomes the Rome Formation and the Conasauga Shale (Figure 6.1.2-3). This facies change runs north-south near the top of the Findlay and Cincinnati Arch Axes, east of the AK Steel site and significantly outside the AK Steel AOR.

Thickness of the Eau Claire ranges from 200 feet in northwestern Ohio to over 550 feet in southwestern Ohio (Figure 6.1.2-4). At the AK Steel site, this formation is approximately 530 feet thick.

Knox

Overlying the Eau Claire Formation is the Cambrian-Ordovician Knox Dolomite. This formation consists of dolomite, shale, sandstone, and stratigraphically restricted limestone. Stromatolitic structures and fossils have been recognized in cores from the Knox (Botoman, 1975).

The lower and middle Knox are Cambrian in age. At the base, the Knox is micro crystalline to coarse crystalline dolomite with interbedded pyritic shale and clear sandstone. The middle Knox is micro crystalline to medium crystalline, partly sandy dolomite and silty dolomite with sand and occasional chert, shale, silicified oolite and pebbles.

The upper Knox is Ordovician in age. This part of the formation is porous to occasionally dense, fine crystalline dolomite. It may occasionally have associated shale, glauconite and chert.

The Knox Dolomite ranges in thickness from less than 100 feet in north central Ohio to more than 1,300 feet in southwestern Ohio, with an approximate thickness of 1,250 feet at the AK Steel site (Figure 6.1.2-5). This variation in thickness across the state can be attributed either to depositional thinning, erosion before the Middle Ordovician, or a regional truncation of individual units.

Wells Creek
The Cambrian-Ordovician Knox Dolomite is overlain unconformably by the Wells Creek Formation. A sharp contact is easily seen on gamma ray - neutron logs and in samples, between the clean Knox dolomite and the clastic, sandy dolomite of the Wells Creek. The Wells Creek consists of sandstone, siltstone, gray, green, and brown shale, and argillaceous and sandy dolomite. Sandstone interbedded with dolomite is generally fine-grained, but may be fine to coarse-grained.

The west-east cross section (Drawing 4) and the north-south cross section (Drawing 3) demonstrate that the Mt. Simon Sandstone, the Eau Claire Formation, the Knox Formation, and Wells Creek Formation are continuous across the AK Steel site. Lithology within these formations, characterized by curve signatures on the geophysical logs, are also continuous beneath the AK Steel site.

Black River
The Ordovician Black River Limestone conformably overlies the Wells Creek. This formation consists of lithographic limestone with sandstone, chert, and brown shales. Thin interbedded limestone is present in the upper section of the Black River, while the lower section contains lenses of fine-grained brown dolomite. The Black River Limestone terminates with a volcanic metabentonite zone (Botoman,1975).

Trenton
Overlying the Black River is the Ordovician Trenton Limestone or Lexington Limestone. The Trenton is a fine to medium-grained, fossiliferous, buff to light brown limestone and dolomitic limestone.

The Trenton Limestone is overlain by the Upper Ordovician Cincinnatian Series, a succession of fossiliferous limestone and gray calcareous shale or siltstones. The Cincinnatian Series is subdivided into the Kope, Fairview, Grant Lake, Bull Fork, and Drake Formations. In this document, these units have not been differentiated.

The west to east cross section (Drawing 4) and the north-south cross section (Drawing 3) demonstrate the continuity of the different formations of Ordovician age. Geophysical log calculations for porosity presented in Table 6.1.2-I indicate that the different formations that make up the middle and upper Ordovician section in AK Steel UIC Well No. 1 have the potential to serve as additional alternating buffer or confining units between the top of the Knox Formation and the base of the lowermost USDW. The porosities for the formations in the AK Steel UIC Well No. 1 are comparable to porosities in the DGS 2627 core test, indicating that the formation porosities are relatively continuous across the area of interest.

TABLE 6.1.2-I
Average Porosity From Well Log Calculation

	AK Steel No. 1		DGS 2627	
Formation	Porosity Interval (Depth in feet, KB)	% Por.*	Porosity Interval (Depth in feet, KB)	% Por.**
Trenton	600-635	14%	1030-1050	12%
Black River	660-1094	3%	1080-1550	1%
Wells Creek	1118-1152	13%***	1550-1600	15%
Knox	Deeper than 1193	6%***	1608-1650	5%

* AK Steel No. 1 calculations from sonic log using Schlumberger Chart Por.-3
** DGS 2627 calculations from neutron-density log using Schlumberger Chart CP-1c
*** Average of sonic and neutron porosity values

Pleistocene sediments which unconformably overlie the Cincinnatian Series consist of sand, gravel, and boulders deposited by glaciation. Surface material consist of fluvial unconsolidated deposits.

6.1.3 Regional Structure

Southwestern Ohio is part of a central craton characterized by broad sedimentary basins and arches. Prominent structural features include the Cincinnati Arch extending from southwestern Ohio into Kentucky, the Ohio-Indiana Platform, the Appalachian Basin to the east and southeast, and the Illinois Basin to the southwest (Figure 6.1.3-1).

The ODNR Division of Geological Survey (DGS, Hansen, 1997) described the Precambrian history of Ohio as beginning with the doming and subsequent emplacement of a vast granite and rhyolitic sheet about 1.4-1.5 billion years ago, forming the Granite-Rhyolite Province. Doming continued and caused the crust to rift or separate, creating the East Continent Rift Basin, as well as other basins. Volcanism and sedimentation occurred within the rift systems, including initial deposition of the Middle Run formation. Approximately 990-880 million years ago (mya) continental collision occurred east of Ohio, causing extensive crustal compression, thrusting, and development of foreland basins along the Grenville Front. Extensive sedimentation and deformation accompanied this compressive system. The Grenville Front demarks relatively undisturbed igneous rocks to the west of Ohio and greatly metamorphosed rocks east of this front line. Figure 6.1.2-1 shows the generalized location of the Grenville Front.

Occurrence of a Precambrian rift structure near the AK Steel site was identified by DGS 2627, which was cored from October 1987 and May 1989. This was a scheduled basement test located in Warren County near the town of Lytle, approximately 12 miles northeast of the AK Steel Middletown Works site (Shrake et al., 1990). The objective of the core hole was to gain geologic information on Lower Paleozoic and older rocks in western Ohio. Prior to drilling, it was anticipated that a crystalline basement would be encountered below the Mt. Simon Sandstone. However, a sedimentary formation (Middle Run Formation) was encountered at 3,470 feet below the surface and continued to the total depth of 5380 feet below the surface.

After 700 feet of the Middle Run Formation had been drilled in DGS 2627, it was decided to conduct an 8 mile (12.8 km) east-west seismic survey (Seismic Line ODNR-1-88) centered on the core hole. Because the purpose of the survey was to show as much detail as possible about the Lower Paleozoic section, survey parameters were chosen to optimize resolution between depths of 3000 and 6000 feet (Shrake et al., 1990). Interpretation of the seismic profile revealed a steep dip of the basement to the east with as much as 5000 feet of relief within the rift. Thrust faulting and normal faulting of the basement has been interpreted based on the seismic data; however, Shrake et al. (1991) did not show that the identified thrusts terminate at or within the Middle Run Formation and the thrusts do not extend to the Paleozoic Section. The seismic data show the Paleozoic strata to be dipping from east to west, indicating an angular unconformity at the contact between the Cambrian and Precambrian (Figure 6.1.3-2).

At about the same time OGS 2627 was drilled, seismic data was collected north of the AK Steel site to evaluate basement conditions and features. A Consortium for Continental Reflection

Profiling (COCORP) east-west seismic reflection profile was conducted in western Ohio in 1987 through Mercer, Auglaize, Shelby, Logan, Union, and Delaware Counties (Hansen, 1989). This seismic line, labeled Ohio Line 1 or OH-1, is located approximately 60 miles north of the AK Steel facility. The COCORP seismic profiling across Ohio was to gather information on the Precambrian basement rocks to a depth of 30 miles, the approximate depth of the Mohorovicic Discontinuity. Because of this, the 2,500 to 13,000 feet of sedimentary Paleozoic section appears as little more than a thin veneer overlying the Precambrian basement. Analysis of the western portion of the OH-1 seismic line from the Indiana border to Bellefontaine revealed an extensive sequence of stratified Precambrian rocks. A Precambrian rift zone approximately three miles deep was also identified extending from south of Celina in Mercer County to near Bellefontaine in Logan County. A series of east-dipping reflectors extending from a 30-mile wide zone just east of Bellefontaine can be traced from the top of the Precambrian rocks to mid-crustal depths. This is interpreted as the structural boundary known as the Grenville Front. The seismic signature across the near surface exposure of the Grenville Front in Canada is identical to what is interpreted as the Grenville Front in the COCORP OH-1 seismic line (Hansen, 1989).

To fulfill permit requirements in 1991, AK Steel acquired 28 kilometers of seismic reflection data to identify the presence or absence of geological structural features vertically in the sedimentary section above and below the Mt. Simon Sandstone and horizontally within the two mile AOR for their injection wells. The objective of the original processing of the seismic data did not include resolving the stratigraphic details of the Precambrian sedimentary section below the Mt. Simon Sandstone. However, the results of the AK steel survey did indicate a sequence of stratified units much thicker than anticipated. Several strong horizontal or gently dipping reflectors were identified under the AK Steel site. These reflectors were laterally continuous and were interpreted as boundaries between stratigraphic units of different character. Features in the seismic data that might suggest faulting were not apparent.

Richard and Wolfe (1995) examined information from the DGS 2627 core hole, the Consortium (OH-1) - Wright State University (WSU) seismic line and the AK Steel seismic data. Richard and Wolfe concluded that the Middle Run Formation is lithologically uniform and has experienced little deformation in the areas examined. The Middle Run averages 1800 feet in thickness and lies on complexly deformed Precambrian rocks. Richard and Wolfe concluded that these older rocks have experienced deformation by early normal faulting followed by thrusting from the lowermost portions of the Middle Run, the majority of the displacement on these faults appears to pre-date the deposition of the Middle Run Formation.

The Cincinnati Arch Consortium (CAC) consisting of the Ohio, Indiana, and Kentucky Geological Surveys conducted research funded by private industry to define the rifting complex referred to as the East Continent Rift Basin (ECRB)(Drahovzal et al., 1992; Wickstrom et al., 1992). The research of the CAC was conducted between September 1990 and December 1991. The CAC concluded that the ECRB is a Proterozoic rift basin and is likely the southern extension of the Keweenawan MRS that developed in Iowa, Wisconsin, Minnesota, Lake Superior region, and Michigan. This association is based on lithologic and stratigraphic similarities, geochemistry of associated basalts, structural style, and magnetic and gravimetric continuity.

The age, genesis, and structural history of the Phanerozoic Ohio systems and Middle Run Formation has been the subject of dozens of studies that were initiated after the aforementioned seismic data revealed the presence of deep basement structures. Most recently, Baranoski et al. (2009) examined reprocessed seismic data for a Ohio Consortium for Continental Reflection Profiling (COCORP) line OH-1, which is a west-east seismic reflection survey that was run through central Ohio from the Granite-Rhyolite province through the Grenville Front. The study clarified the timing of the East Continental Rift System (and Fort Wayne Rift) with respect to the Grenville Orogeny, which also shed light on the age of the Middle Run Formation that was deposited prior to Cambrian-age Mt. Simon sandstones. Baranoski et al. proposed that major regional unconformities associated with crustal shortening developed on the Eastern Granite-Rhyolite Province and Grenville terrains during the Precambrian, followed by development of extensive fault-bounded rift basins (e.g. Fort Wayne and Eastern Continental Rift System in Western Ohio) as continental collision took place in eastern Ohio. Westward-advancing Grenville thrusts then developed, as did new foreland basins over previously formed rift basins, including deposition of sedimentary sequences in those basins. Continued Grenville thrusting created segmented foreland basins that were thrust westward, along with earlier rift basins. This was followed by late Precambrian-Middle Cambrian erosion that removed much of the sequence, culminated by deposition of Cambrian sedimentary sequences (Mt. Simon) (Baranoski et al., 2009).

It should be pointed out that other authors such as Wolfe, et al. (1993), believe that data suggest the Middle Run formation is younger than both the Eastern Granite-Rhyloite or Grenville province because of observed seismic contrasts along the COCORP lines, and because of the presence of rhyolitic sands within the Middle Run, indicating granite-rhylolite sources. Also, Richard et al., 1995 do not believe the existing geophysical data support the genetic relationship between the western Ohio rifting and the MRS.

The other prominent structural features in southwestern Ohio are the elements of the Ohio-Indiana Platform, which has been described as a broad, relatively unwarped structural platform joining the Cincinnati Arch in southwestern Ohio with the Findlay Arch to the northeast and the Kankakee Arch to the northwest (Green, 1957). It is generally accepted that these positive features were derived from the subsidence of the surrounding Michigan, Illinois, and Appalachian basins beginning in the early Ordovician Period rather than uplift of these structural elements (Janssens, 1967). In southwestern Ohio, the Cincinnati Arch and the Ohio-Indiana Platform are important structural features. They are highly eroded, with the central portions consisting of rocks of the Silurian or Ordovician Systems overlain by Pleistocene glacial deposits. Progressively younger Paleozoic units are present on the flanks.

A review of regional structure maps shows a gentle southwest dip across Butler, Montgomery, and Warren Counties at the Precambrian surface (Figure 6.1.3-3) and on top of the Eau Claire Formation (Figure 6.1.3-4). At the top of the Knox Dolomite, the dip is very gentle toward the northeast across the same area (Figure 6.1.3-5). A review of available data indicates that there is no faulting of the Paleozoic section within the area of interest.

6.2 Local Geology

The following sections summarize site-specific geology of the AK Steel site. Table 6.2-I lists the historic well site used to evaluate local and wellsite geology at AK Steel.

Table 6.2-I
Historic Sources of Geologic Data

Well No.	Item	Location in 2012 Permit Application
AK Steel UIC No. 1	Sample Description UIC Well No. 1 and Well No. 2, American Industrial Disposal Systems, Inc., 1967 and 1968	Appendix 6.2.4-A
	Core Analysis and Description UIC Well No. 1, Geo-Engineering Laboratories, Inc. 1967	Appendix 6.2.4.2-A
	Geophyiscal Logs: Induction Electric Formation Density, Gamma Ray-Neutron, Sonic, March 1967	Not Provided; see previous permit applications
AK Steel UIC No. 2	Sample Description UIC Well No. 1 and Well No. 2, American Industrial Disposal Systems, Inc., 1967 and 1968	Appendix 6.2.4-A
	Core Analysis Report Armco; UIC Well No. 2, By Geo-Engineering Laboratories, Inc. 1968	Appendix 6.2.4.2-B
	Pressure Transient Test Report Armco Injection Well No. 2 and Falloff and Interference Test, J.O. Well Service, Inc. October 1989	Not provided, see Appendix 9.2-D of 1991 Repermit Application
	Logs: Compensated Density, April, 1968	Not provided; see previous permit applications
DGS 2627	Core Flow Study, Envirocorp Laboratory, 1990 (Table 6.2.4.2-I),Petrographic Study of Thin Sections, Terratek Geoscience Services, 1990	Not provided, see Appendix 6.2.4.2-D of 1991 Repermit Application
	Logs: Gamma Ray Neutron, Density (4-89)	Not provided, but reproduced in Drawings 3 and 4

6.2.1 Topographic Description

The two AK Steel Middletown Works injection wells are located in Section 8, Lemon Township, Butler County, Ohio, in Middletown, Ohio on the Dicks Creek Flood Plain about two miles east of the Great Miami River Flood Plain. Here the Great Miami River flood plain is 620 feet to 670 feet in elevation and the Dicks Creek flood plain is 610 feet to 670 feet in elevation (Drawing 1). These flood plains are located in valleys that were carved by Illinoisan and Wisconsin glaciation and filled with glacial drift. A mantle of alluvium was stream deposited over the glacial outwash.

Glaciation created rolling, rounded hills with maximum elevation of 900+ feet. Glacial deposits are less than 25 feet thick on the hills or plateaus and exhibit a maximum thickness of approximately 180 feet in associated valleys (Stout Ver Stug and Lamb 1943). At the AK Steel wells, glacial deposits are approximately 95 feet thick.

6.2.2 *Glacial Deposits*

The AK Steel Plant is located on glacial outwash deposits occupied by Dicks Creek. The plant site is located about two miles east of the Great Miami River flood plain in Middletown, Ohio. The Great Miami River is located in the Ancestral Great Miami River Valley and Dicks Creek is located in the Ancestral Todds Fork Valley (Drawing 1).

Prior to the Pleistocene Illinoisan glaciation, the region was a plain with surface streams flowing north to the Teays River. The Ancestral Todd Fork River flowed across this regional plain and was responsible for erosion and subsequent formation of the Todd Fork Valley (Drawing 1). Uplift just prior to glaciation caused the Todd Fork to become entrenched in its meanders, forming deep channels.

The Illinoisan ice sheet moved down from the north and overloaded the ancestral Miami River with coarse outwash from the melting front, causing the channel to become filled with sediment. Aggradation of the ancestral Miami River channel raised the outlet of the Todd Fork, resulting in channel fill. Finally, the advancing glacier blocked the mouth of the ancestral Todd Fork at Amanda, just south of Middletown, and caused the waters to back up and form a lake in the Todd Fork Valley. As the glacier advanced up the Todd Fork Valley toward the little Miami River, till was deposited. The backed-up waters of the Todd Fork were diverted southward into the Ohio River and the Todd Fork Valley was left without a through-flowing stream. Glacial melting followed and strong outwash streams resulted in deposition of vast amounts of sand and gravel in the Great Miami and Todd Fork Valleys.

The Illinoisan glaciation was followed by the Wisconsin glaciation. Aggradation again occurred in the Miami River channel and the valley at Amanda was blocked for a second time, forming another lake in the Todd Fork Valley. The advancing ice sheet deposited a second layer of till (Shoecraft et al., 1943). When the Wisconsin ice retreated, strong outwash streams resulted in the deposition and reworking of vast amounts of sand and gravel in the Great Miami River Valley. Later, the abandoned Todd Fork Valley was occupied by Dicks Creek and its tributaries (Layne, 1979).

The rocks underlying the alluvium and Pleistocene glacial drift range in age from Ordovician sedimentary rocks to the Precambrian basement complex. Younger Paleozoic rocks were either not deposited or were removed by erosion.

6.2.3 *Local Stratigraphy and Continuity*

Local stratigraphy is summarized in Table 6.2.3-I, which is based on information derived from the AK Steel disposal wells. Depths and thicknesses of geologic formations shown in Table 6.2.3-I are based primarily on electric logs, but sample picks (drill bit cutting descriptions) were used to pick shallow sequences if no log picks were available. All formation tops which are based on sample picks are indicated with an asterisk in Table 6.2.3-I.

No deep wells other than the two AK Steel wells are within the AK Steel Area of Review. Therefore, interpretations such as geologic dip and stratigraphic continuity are interpolated from regional data. Comparison of formation thickness in the AK Steel wells and the DGS Well 2627, using the formation tops reported in the CAC report, reveals the following variations:

Interval	Thickness(ft) DGS 2627	Thickness(ft) AK Steel	% Difference
Black River to Knox	520	491	-6%
Knox to Eau Claire	1068	1263	+18%
Eau Claire to Mt. Simon	554	540	-3%
Mt. Simon to Middle Run	228	280	+23%

Although these numbers indicate varying degrees of thinning and thickening of these formations at the AK Steel site relative to the DGS 2627 well, they do not constitute abrupt changes in the thickness of the intervals. Furthermore, except for a slight thinning in the Eau Claire, the thickening of the Mt. Simon and the Knox at the AK Steel site indicate favorable changes in the geologic conditions in terms of the injection activity (i.e. thicker injection zone and thicker confining zone).

TABLE 6.2.3-1
STRATIGRAPHIC NOMENCLATURE – DEPTHS - THICKENESSES

		ARMCO WDW NO. 1 GL - 659' KB – 8' KB ELEV – 667'					ARMCO WDW NO. 2 GL – 667' KB – 4' KB ELEV – 671'				
SYSTEM	FORMATION	KB DEPTH TO TOP	THICKNESS	MSL ELEVATION	DISPOSAL WELL UNIT		KB DEPTH TO TOP	THICKNESS	MSL ELEVATION	DISPOSAL WELL UNIT	
QUARTERNARY	RECENT ALLUVIUM	--	--	--			4'	5'	667'		
QUARTERNARY	GLACIAL DRIFT	8'	100'	659'			9'	91'	662'		
UPPER ORDOVICIAN	CINCINNATIAN GROUP	100'	422'	567'	OVERLYING UNITS 1164'		100'	424'	567'	OVERLYING UNITS 1176'	
UPPER ORDOVICIAN	TRENTON LIMESTONE	522'	144'	145'			524'	145'	147'		
UPPER ORDOVICIAN	BLACK RIVER LIMESTONE	666'	482'	1'			669'	489'	-2'		
UPPER ORDOVICIAN	WELLS CREEK FORMATION	1148'	24'	-481'			1158'	22'	-487'		
CAMBRIAN	KNOX DOLOMITE	1172'	1251'	-505'	CONFINING ZONE 1251'		1180'	1236'	-509'	CONFINING ZONE 1236'	
CAMBRIAN	EAU CLAIRE FORMATION	2423'	556'	-1756'	ARRESTMENT INTERVAL 477'	INJECTION ZONE 873'	2416'	555'	-1745'	ARRESTMENT INTERVAL 488'	INJECTION ZONE 868'
CAMBRIAN	MOUNT SIMON FORMATION	2979'	257'	-2312'	INJECTION INTERVAL 396'		2971'	258'	-2300'	INJECTION INTERVAL 381'	

6.2.4 *Wellsite Lithology*

The original descriptions of formations logged in AK Steel UIC Well No. 1 and UIC Well No. 2 are given in Appendix 6.2.4-A. These descriptions are similar to regional lithologies. Depths and thicknesses for each formation, as measured in AK Steel UIC Well No. 1 and UIC Well No. 2, are provided in Table 6.2.3-I.

6.2.4.1 Properties of Underlying Units

Neither AK Steel well was drilled deep enough to encounter the interval underlying the injection interval. Based on regional geologic data, it is assumed that AK Steel is underlain by Precambrian age sedimentary rock of the Middle Run Formation.

The Middle Run Formation was first identified as a distinct stratigraphic unit in the AK Steel Middletown Works area during the drilling of DGS 2627 in Warren County, Ohio, approximately 12 miles northeast of the AK Steel site. The drilling was conducted by a consortium comprised of the ODNR, DGS, University of Cincinnati, Wright State University, Paragon Geophysical, Inc., and Stocker and Silter, Inc. The test hole and an associated seismic reflection survey show up to 5,000 feet of pre-Mt. Simon sedimentary rock is present in northern Warren County. The Middle Run is further discussed in Section 6.1.2.

The Middle Run Formation is present beneath the AK Steel injection interval to an unknown depth, although correlation of data from the DGS 2627 well suggest the Middle Run is estimated to be about 1,100 meters thick (Shrake, 1991). Also, seismic data suggest an undetermined thickness of Pre-Middle Run sedimentary units would also be present in the area (Wolf et al., 1993). The portion of the Middle Run present in the AK Steel Wells exhibits decreased porosity with depth and provides lower confinement for the injection interval. Table 6.2.4.1-I provides a summary of Middle Run porosity calculations derived using the Sonic log for UIC Well No. 1. The very low porosity of the Middle Run at the bottom of AK Steel UIC Well No. 1 is consistently reported in multiple publications wherever the Middle Run Formation is encountered. It is this characteristic of the formation that led to its original mis-identification as crystalline basement.

TABLE 6.2.4.1-I
Middle Run Porosity Calculation for AK Steel UIC Well No. 1

Depth	Porosity
3240	14%
3250	8%
3260	8%
3270	10%
3280	3%
3290	3%

As shown in Table 6.2.4.1.I, from 3,280 feet to 3,290 feet, the calculated porosity is only 3%, using the sonic curve. This low porosity value is at the bottom of UIC Well No. 1 and presumably represents deeper Middle Run porosity.

An unconformity occurs between the Mt. Simon and the Middle Run Formations, and it is possible that the higher porosity values measured at the top of the Middle Run (Table 6.2.4-I) in UIC Well No. 1 could be due to weathering and erosional processes that are more effective at the top of a formation where an unconformity is developed. The measured porosities (3%) at 3280′ and 3290′, at the bottom of UIC Well No. 1, are more typical of those porosities measured for the greater portion of the Middle Run in other wells such as ODNR Well 2627 (Shrake et al., 1990). Core analyses were performed by K & A Laboratories on 20 Middle Run samples from ODNR Well 2627 (Shrake et al. 1990). Helium porosity measurements average 1.6% with less than 0.01 millidarcy (md) permeability. A mercury injection capillary pressure test revealed a porosity of 2.5% with air permeability of 0.0481 md. It was concluded that the mercury injection profile for this sandstone sample was characteristic of a very tight rock. Furthermore, it was concluded that the primary porosity of Middle Run sandstones has been reduced to zero by compaction and cementation. It is important to note that although the AK Steel injection wells are completed into the Middle Run, the majority of the injectate is accepted by the top of the injection interval.

Middle Run cementation was described for the ODNR Well 2627 based on lithologic data. Calcite cement of the Middle Run occurs in at least two generations. Early calcite cement is best developed in un-compacted sandstones, but is generally described as patchy in occurrence. A younger generation of calcite cement occurs as final pore filling and fracture-fills throughout the Middle Run. Quartz cement is also developed in the Middle Run in ODNR 2627 and is best developed where quartz grains are abundant. Feldspar and clay cements have also been identified in the Middle Run. Clay cements are common in both the ODNR well and the Texaco/Sherrer well (Jessamine County, Kentucky). Authigenic clay exhibits patchy distribution and where it occurs, often occludes all porosity.

In summary, the Middle Run Formation is characterized by low porosity and low permeability sandstones that are lithologically and laterally continuous in the AK Steel Middletown Works area. The Middle Run Formation provides lower confinement for injection activities.

6.2.4.2 Properties of the Injection Interval

The injection interval for the AK Steel site is defined as that interval between 2900 feet and 3296 feet KB, as measured in the AK Steel UIC Well No. 1The top of the injection interval is conservatively assigned to a depth of 2900 feet KB, as measured in UIC Well No. 1. The top of the injection interval in UIC Well No. 2 is at the equivalent depth of 2904 feet, corrected for KB elevation.

Formations present in the injection interval of AK Steel UIC Well No. 1 include the Eau Claire Formation from 2900 feet to 2979 feet KB, the Mt. Simon Sandstone from 2979 feet to 3236 feet KB, and the Middle Run Formation from 3236 feet to total depth (TD) (3296 feet KB). Characteristics of each are described below.

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The Middle Run Formation is a red and orange arkosic sand, with coarse, angular, weathered feldspar with red clay, quartz, and accessary biotite, magnetite and hornblende. ODNR prepared thin sections in 1988 from several cores originally taken from AK Steel UIC Well No. 2 at depths of 3233 feet, 3255 feet to 3260 feet, and 3275 feet to 3280 feet as described in the 2002 permit application. The section at 3233 feet appears to exhibit some lithologic characteristics of the Middle Run Formation. The other two sections appear to be Middle Run Formation with similar lithology to that seen in DGS 2627. The thin sections show a subangular to subrounded, fine to medium-grain lithic arenite with metamorphic, plutonic, and some sedimentary lithics that are well compacted and low porosity.

The Cambrian Mt. Simon Sandstone is a white to medium-red, fine to coarse-grained, subangular to subround, frosted or smokey, poorly sorted, poorly cemented to loosely consolidated, friable, porous sandstone. Occasional thin green and red, micaceous shale streaks are dispersed throughout the unit. The shale streaks are more abundant near the top of the unit. Pebbly conglomerate beds exist near the base of the unit (Appendix 6.2.4-A).

Within the injection interval in the AK Steel UIC Well No. 1, the average porosity is 12.8% as calculated from the geophysical logs. The porosities range from 6% to 18%. Porosities from the core taken in AK Steel UIC Well No. 2 average 13.5% with porosities ranging from 4.9% to 21.1%. In the modeling section, 13.5% porosity was used. Porosity is less variable than permeability and can be reasonably estimated from core data. The original core analysis report from AK Steel UIC Well No. 1 is provided in Appendix 6.2.4.2-A. The original core analysis report from AK Steel UIC Well No. 2 is provided in Appendix 6.2.4.2-B.

The net permeable thickness of the injection interval is 87.3 feet (see Section 9) as calculated from interference test data. The average permeability is 42 md as calculated from the interference test data (See Section 9). Core permeabilities from AK Steel UIC Well No. 2 ranged from <.10 to 8520 md. Core permeabilities are measured in very small localized samples, while the values of permeability determined from interference test data are based upon investigation of a large volume of in-situ rock. Interference test results will more accurately characterize the behavior of the whole reservoir than will core measurements.

Based on the value of 13.5% porosity, the correlation given by Hall (1953) is used to estimate the pore compressibility of the injection interval rock. The value from this correlation is approximately 4×10^{-6} psi^{-1}. The water compressibility is estimated from correlations published by McCain (1973). At 96°F, water has a compressibility of approximately 3×10^{-6} psi^{-1}. The pore compressibility and water compressibility are added together to obtain an effective compressibility of 7×10^{-6} psi^{-1}.

The viscosity of formation water is determined from the correlations by McCain (1973). At a bottom hole temperature of 96 degrees F, the brine viscosity is 0.71 cp.

Core data from DGS 2627 in Warren County, Ohio, 12 miles northeast of AK Steel, was tested to evaluate formation permeabilities. Six samples were taken from the vertical interval in the core hole that correlates with the injection interval at AK Steel; four of the samples were from the Eau Claire, one was transitional between the Eau Claire and the Mt. Simon, and one is

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within the Mt. Simon. Horizontal air permeabilities with overburden pressure range from 0.27 md to 7.6 md. Three of the six samples had no measurable vertical air permeability, while the other three had values of 1.3, 0.4, and 2.0 md. In all samples, horizontal air permeability exceeded vertical air permeability by at least a factor of 2.4.

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TABLE 6.2.4.2-I

CORE FLOW STUDY RESULTS, WARREN COUNTY CORE HOLE NO. 2627

Sample	Depth (Feet)	Length of Core (cm)	Air Permeability (MD) Horizontal			Porosity %	Fluid permeability (MD) Pulse Test	
			Ambient	Overburden	Vertical		Waste	Brine
1	2690.5 - 2691	3.378	0.021	0.005	—	0.3		
2	2714.5 - 2715	2.286	0.058	0.003	>.01	8.1		
3	2752.6 - 2753	1.914	0.040	>.001	>.01	2.3	1.4 x 10-4	1.3 x 10-4
4	2826.3 - 2827	2.062	0.023	>.001	>.01	0.2		
5	2869.4 - 2870	1.962	0.022	>.001	>.01	1.9		1.1 x 10-4
6	2900 - 2900.5	1.616	0.151	0.041	>.01	4.2		
7	2949.5 - 2950	2.142	0.072	0.025	>.01	4.2		
8	2999 - 2999.6	2.218	0.031	0.002	>.01	3.2	1.1 x 10-4	2.8 x 10-4
9	3015 - 3015.6	2.052	0.029	0.003	>.01	3.1		
10	3049 - 3049.6	2.204	0.025	0.002	>.01	3.0		
11	3078 - 3078.5	2.209	0.030	0.003	>.01	3.6		
12	3107 - 3108	1.984	19.4	18.9	0.86	14.0		
13	3127.2 - 3128	1.838	3.6	1.4	>.01	15.6		
14	3149.4 - 3149.9	1.537	0.015	>.001	>.01	1.3		
15	3160 - 3160.5	2.152	0.072	0.027	>.01	4.1		
16	3194 - 3194.5	1.737	0.074	0.029	>.01	9.9		
17	3210 - 3211	2.032	8.4	7.6	1.3	19.7		
18	3222 - 3222.8	1.492	0.669	0.298	0.04	7.4		
19	3238.3 - 3239	2.350	0.060	0.027	>.01	8.0	2.6 x 10-4	1.6 x 10-4
20	3243 - 3243.5	1.936	8.3	4.9	2.0	6.7		

For the purposes of petition modeling, it was assumed that the entire vertical extent of the injection interval (up to 2900 feet KB in AK Steel UIC Well No. 1) is in full pressure communication with the open hole interval. In fact, the core tests show that pressure attenuation is likely to occur, due to intervals with low permeability and also due to the anisotropy of higher permeability intervals.

Core flow study methods are presented in Appendix 6.2.4.2-C. The petrographic study conducted on samples from the Eau Claire and Mt. Simon is included in Appendix 6.2.4.2-D. Properties of the injection interval are summarized in Table 6.2.4.2-II.

TABLE 6.2.4.2-II
Summary of Injection Interval Characteristics

	UIC Well No. 1	UIC Well No. 2
Injection Interval	2900' – 3296' KB	2904' KB – 3285' KB
Porosity (%) from Geophysical	12.8%	
Porosity (%) from Core		13.5%
Calculated Net Permeable Thickness*	87.3 ft	87.3 ft
Calculated Permeability*	55 md	55 md
Calculated Compressibility	$7x10^{-6}$ psi	$7x10^{-6}$psi
Calculated Viscosity*	0.71 cp	0.71 cp

* See Section 9

6.2.4.3 Properties of the Arrestment Interval

The arrestment interval is defined as the interval from 2423 feet to 2900 feet KB depth as measured in UIC Well No. 1. The arrestment interval consists of the upper 477 feet of the Eau Claire Formation.

The Cambrian Eau Claire Formation is composed of sandstone and shale with minor amounts of siltstone, dolomite, and limestone. Shale becomes more dominant in the upper 200 feet of the formation. The sandstone facies is composed of white to dark gray, sometimes yellow, pink, or orange, fine to medium-grained, subangular to subrounded quartz grains with some glauconite and pyrite. It is slightly micaceous and calcareous. The shale facies is dark gray, greenish-gray or red, micaceous, glauconitic, and slightly calcareous. The dolomite is gray and crystalline and the limestone is gray.

Core permeability measurements taken from AK Steel UIC Well No. 1 provide site-specific information about the permeability of the Eau Claire. Fluid permeabilities measured in the cores range from 3.43×10^{-2} to less than 1×10^{-6} md. Eight of the ten samples tested had no measurable fluid permeability. Core permeabilities are presented in Table 6.2.4.3-I.

TABLE 6.2.4.3-I
Core Flow Study Results, Eau Claire Formation
AK Steel UIC Well No. 1

SAMPLE NO.	DEPTH	VERTICAL PERMEABILITY TO WATER (MD)
1	2858.9-59.3	3.43 X 10-2
2	2863.0-63.5	1.39 X 10-4
3	2869.5-70.0	<1.00 X 10-6
4	2870.0-87.5	<1.00 X 10-6
5	2875.0-75.6	<1.00 X 10-6
6	2876.4-76.8	<1.00 X 10-6
7	2877.4-77.8	<1.00 X 10-6
8	2878.3-78.7	<1.00 X 10-6
9	2879.0-79.6	<1.00 X 10-6
10	2880.4-80.8	<1.00 X 10-6

Source: Geo-Engineering Laboratories, Inc., Mt. Vernon, IL 1967

Samples of the Eau Claire from ODNR Well DGS 2627 were available for testing and study. The Eau Claire in DGS 2627 is correlative with the Eau Claire seen in the AK Steel wells.

A correlation between DGS 2627 and AK Steel UIC Well No. 1 is presented in Figure 6.2.4.3-1. The correlations shown in this figure were presented in the 2002 permit application and were retained for continuity. Neutron Gamma Ray logs were used to perform the correlation, based solely on the similarities of the log signatures, not on geologic time or lithological comparison of drill cuttings. At 2979 feet in AK Steel UIC Well No. 1, the Gamma Ray curve increases upward. This is accompanied by an increase in the neutron curve. These changes are also seen in the core hole at 3240 feet. In both wells, this is where the top of the Mt. Simon is picked. At 2422 feet in AK Steel UIC Well No. 1, the Gamma Ray curve decreases upward. This is accompanied by a decrease in the neutron curve. In the core hole, the Gamma Ray and Neutron logs decrease upward at 2678 feet. At 2510 feet in AK Steel UIC Well No. 1, the Gamma Ray curve decreases downward, with the boundary marked by a spike of 90 API (American Petroleum Institute) units. In the core hole, a corresponding decrease downward in the Gamma Ray is seen at 2773 feet with the boundary marked by a spike of 80 API units. In AK Steel UIC Well No. 1, the Gamma Ray decreases downward at 2845 feet. In the core hole, a corresponding Gamma Ray decrease downward is found at 3090 feet.

The arrestment interval in AK Steel UIC Well No. 1 is from 2423 feet to 2900 feet. The correlative interval in the core hole extends from 2678 feet to 3150 feet.

The measured core permeabilities of the Eau Claire and Mt. Simon in the DGS 2627 core hole are presented in Table 6.2.4.2-I. Of the 19 samples tested for vertical permeability, 14 are from the vertical interval 2678 feet - 3150 feet, which is correlative with the arrestment interval at AK Steel (Figure 6.2.4.3-1). Of these 14 samples, 1 sample had a measurable vertical air permeability, while the other 13 had values less than the 0.01 md detection limit. Three brine permeabilities were measured, ranging from 1.1×10^{-4} md to 2.8×10^{-4} md. Core test methods are discussed in Appendix 6.2.4.2-C.

In DDNR Well DGS 2627, three facies were identified from thin section within the arrestment interval. These are:

1. Bioclastic Oolitic Packstone/Grainstone facies (one sample: 2690.8 feet). This sample had a measured effective porosity of 0.3%.

2. Silty Dolomite/Dolomitic Siltstone facies (eight samples: 2714.6 feet - 3015.2 feet). All samples in this group had vertical permeabilities of less than the 0.01 md detection limit. Average effective porosity for the eight samples is 3.4%.

3. Glauconitic Fine-Grained Sandstone facies (5 samples: 3049 feet - 3149.9 feet). One sample had a measurable vertical air permeability. This was the sample 3107 feet - 3108 feet, which had a value of 0.86 md. The horizontal air permeability of 18.9 md for this sample under overburden pressure shows that the Eau Claire is anisotropic in this interval. An interval with a relatively high horizontal permeability provides a valuable buffer to attenuate possible fluid pressure buildup. According to the report on thin section examination of the test hole core (Appendix 6.2.4.2-D of the 1991 Repermit Application), porosity in the sample 3107 feet -3108 feet has developed due to dissolution of dolomite. Secondary fracture porosity was not noted.

The top of the injection interval at AK Steel correlates to a depth of approximately 3150 feet in the ODNR DGS 2627 test hole (Figure 6.2.4.3-1). From the 14 vertical air permeability measurements taken from the interval in the test hole correlative with the arrestment interval, an effective vertical permeability may be calculated. First, the conservative assumption is made that the permeable zone seen in sample 3107 feet - 3108 feet extends 90% of the vertical distance to each adjacent sample, or from 3081 feet to 3125 feet. Next, the remaining vertical extent of the arrestment interval (for which no permeabilities above detection limits were measured) is conservatively assumed to have a vertical permeability equal to the detection limit of 0.01 md. The effective vertical permeability of the units correlative with the arrestment interval is then equal to $472/(428/0.01+44/0.86) = 1.1 \times 10^{-2}$ md. This value is based entirely on air permeabilities, which are known to typically exceed fluid permeabilities by approximately two orders of magnitude for low permeability cores. Based on these results, the effective vertical permeability of the interval correlative to the arrestment interval will not exceed 1.1×10^{-2} md, and is more likely to be on the order of 1.1×10^{-4} md.

Core data for the Eau Claire is also available from Betty Leuenberger No. 1 well in Allen County, Indiana. Of the 169, one-foot intervals tested, 108 had fluid permeabilities of less than the 1.0×10^{-6} md detection limit. Only four tested intervals had fluid permeabilities higher than 10^{-2} md, and no samples exceeded 1 md. The full core test results for this well are presented in Appendix 6.2.4.3-A.

Core permeability measurements taken from AK Steel UIC Well No. 1, DGS 2627 and Betty Leuenberger No. 1 well (Appendix 6.2.4.3-A) show that the effective vertical permeability of the Eau Claire does not exceed 10^{-2} md, and is more likely to be 1×10^{-4} md or less. The effective vertical permeability of 10^{-1} md assigned to the arrestment interval in the model builds in a margin of safety of one to three orders of magnitude.

6.2.4.4 Properties of the Confining Zone

The confining zone at AK Steel Middletown Works consists of the Knox Dolomite. The confining zone extends from 1172 feet to 2423 feet KB depth as measured in AK Steel UIC Well No. 1, and is 1251 feet thick.

The Cambrian-Ordovician Knox Dolomite is primarily a dolomite. Based on AK Steel site-specific information, the upper 30 feet of the Knox is a sandstone that is comprised of light gray to clear, medium-grained, subrounded quartz grains, with some pyrite, chert grains, and hematite stains, becoming dolomitic toward the base. The next approximately 1130 feet of the Knox is composed of white to brown, very fine to coarse-grained, crystalline to sugary dolomite, containing pyrite, white and light blue oolitic chert, and dolomite rhombs with fossil fragments. Portions of the Knox are vuggy and thus the unit contains some intervals capable of acting as buffering units. Occasional frosted subangular quartz grains cemented with calcium carbonate are noted, as are glauconitic siltstones. The interval from 2340 feet to 2430 feet is composed of dark gray to black shale.

Based on calculations made using AK Steel UIC Well No. 1 geophysical logs, the Knox Dolomite porosity ranges from 0% to 4%. A few thin beds approximately 3 to 5 feet thick with porosities of approximately 9% are scattered throughout the formation. Interpreted porosities in the Knox Dolomite are presented in Table 6.2.4.4-I.

Porosities for the Knox were determined from geophysical logs in the following manner. The logs were divided into sections which had consistent logged density and neutron porosity values. The porosity and density were then cross plotted on Schlumberger Chart CP-1c, "Porosity and Lithology Determination from Formation Density Log and Compensated Neutron Log for Fresh Water Liquid Filled Holes." The cross plot yielded a value for formation porosity and general lithology.

TABLE 6.2.4.4-I
Calculated Porosities of the Knox
NEUTRON DENSITY

DEPTH	%N	Pb	CROSS PLOT POROSITY
1172-1202	7%	2.70	4%
1202-1310	0%	2.70	1%
1310-1365	1.5%	2.65	3%
1365-1370	10%	2.65	9%
1370-1520	2%	2.70	2%
1520-1523	7%	2.55	9%
1523-1560	2%	2.70	2%
1560-1600	1%	2.73	1%
1600-1630	2.5%	2.70	1.5%
1630-1820	0%	2.73	0%
1820-1860	1.5%	2.65	1.5%
1860-1890	0%	2.74	0%
1890-1950	0%	2.74	0%

DEPTH	%N	Pb	CROSS PLOT POROSITY
1950-1980	1%	2.70	1%
1980-2010	1%	2.67	0.5%
2010-2050	0.5%	2.73	1%
2050-2070	0.5%	2.75	0%
2070-2078	1%	2.65	1%
2078-2082	10%	2.60	9%
2082-2110	1%	2.67	0%
2110-2230	0%	2.74	0%
2230-2270	0%	2.75	0%
2270-2295	0%	2.73	0%
2295-2310	0%	2.70	0%
2310-2365	0%	2.75	0%
2365-2380	5%	2.64	2%
2380-2420	2.5%	2.64	3%

6.2.4.5 Properties of the Overlying Units

The confining zone is overlain by the Wells Creek Formation, Black River Limestone, Trenton Limestone, and Cincinnatian Group as well as unconsolidated glacial deposits. These units are approximately 1072 feet thick in total at AK Steel. Lithologic descriptions of the formations are based on AK Steel well cuttings data.

The Ordovician Wells Creek Formation is a light gray to clear sandstone that is; medium grained with subrounded quartz grains, some pyrite and chert grains, and hematite stains. The formation becomes dolomitic towards the base. The Wells Creek is permeable, and serves as a buffer unit at the top of the confining zone.

The Ordovician Black River Limestone is composed predominantly of limestone. It is a very light tan to brown, hard dense and crystalline, and argillaceous limestone with black chert, fossils, pyrite and free calcareous shale. There is some hematite staining. Beds of calcareous greenish gray shale are present. The lower 100 feet of the Black River becomes sandy and dolomitic with some pyrite, chert grains and hematite stains. The Ordovician Trenton Limestone is a light brown to dark crystalline limestone with brachiopod fragments, translucent pieces of gray chert, free calcite grains and silty calcareous shale.

Rocks of the Cincinnatian Series of the Ordovician System are composed of alternating units of shale and limestone. The limestone facies is gray to brown crystalline limestone, fossiliferous, sometimes shaley or silty, containing occasional disseminated pyrite and calcite. The shale facies is greenish gray, slightly calcareous shale, with interbeds of limestone that may be fossilferous.

The Cincinnatian Series is unconformably overlain by Pleistocene glacial and glaciofluvial sediments. The properties of the glacial materials are discussed in Section 6.2.2.

6.3 Seismicity

The following sections summarize information available regarding the lack of historic seismic events in the vicinity of the injection well facility.

6.3.1 Seismic Activity

The AK Steel site is located in an area of the United States which is classified as earthquake risk zone No. 2, where not more than moderate damage from earthquakes may occur (Figure 6.3.1-1). There have been 94 earthquakes (or seismic events) recorded within a 100 mile (160 kilometer) radius of the AK Steel site. Table 6.3.1-I lists the epicenter of each of the 94 seismic events. Earthquake intensities are given in the modified Mercalli Intensity Scale of 1931 (Table 6.3.1-II). All of the recorded earthquakes have had intensities that ranged from I to VIII on the Modified Mercalli scale. The nearest epicenter to the AK Steel site was approximately 9 miles (14 kilometers) to the north northwest. The event occurred in 1834, and had an intensity of IV. The most recent earthquake occurred on September 30, 2008, approximately 64 miles (103 kilometers) northeast of the AK Steel site, and had an intensity of IV. The only recorded earthquake with an intensity of VIII within 100 miles of AK Steel occurred on March 9, 1937, approximately 68 miles (110 kilometers) from AK Steel. No earthquake has ever been recorded which has had an epicenter in the AK Steel area of review, as calculated in Section 5.2. Locations of seismic stations located within a grid bounded by 80.5 to 88.0 degrees latitude and 36.5 to 42.5 degrees longitude are listed in Table 6.3.1-III. This list includes all seismic stations within 200 miles of the AK Steel facility as of August, 2011.

6.3.2 Induced Seismicity

Only one earthquake has been detected within 10 miles of the AK Steel site, which occurred long before the installation of the injection wells. It was reported in 1834, and was approximately 9 miles to the north northwest. No earthquakes have been detected within 10 miles of the AK Steel site after well installation or operation. There is no evidence that injection at AK Steel has ever induced seismicity or could induce seismicity in the future.

To determine if the falloff test portion of the June 1995 pressure transient testing showed any evidence of pressure boundaries within the injection interval, the following data was used:

Total Testing Time:	24 hours 12	=	t
Permeability:	42 md	=	k
Porosity:	13.5%	=	ϕ
Viscosity:	0.71 cp	=	V
Compressibility:	7.0×10^{-6} psi^{-1}	=	C
Radius of Investigation:			

$$r_i = \sqrt{\frac{k\,t}{948\phi VC}}$$

Based on the above formula (Sabet, 1991), the typical radius of investigation is approximately 890 feet from the injection well. The interpretation of this falloff test indicated no boundaries within the radius of investigation. The pressure falloff tests have shown no evidence of nearby boundary effects that could suggest fault related seals within the radius of investigation.

The absence of recorded or detected seismic activity in proximity to the AK Steel Middletown Works facility, and the absence of identifiable boundary effects in site-specific data, continue to support that the site meets all regulatory criteria of OAC Chapter 3745-34 regarding seismic areas and activity.

TABLE 6.3.1-I

Earthquakes Within 100 Miles (160 Kilometers) of AK Steel

Year	Month	Day	North Latitude	West Longitude	Magnitude		Intensity (Mercalli)	Radial Distance (km)
1817	9	5	38.5	84.5	3.1	MI	IV	110
1834	11	20	39.6	84.3	3.5	FA	IV	14
1839	9	5	38.6	83.8	3.1	MI	IV	109
1843	6	19	40.1	83.8	3.5	MI	IV	83
1848	4	6	39.65	82.53	3.7	FA	IV	157
1854	1	11	39.4	83.7	3.5	MI	IV	57
1859	9		39.1	84.2	2.5	FA	I	45
1864			39.1	84.2	2.5	N/A	I	45
1869	2	20	38.1	84.5	3.4	MI	V	155
1870	1	16	39.71	82.6	2.9	MI	II	152
1873	1	4	40.2	83	3.8	MI	IV	140
1873	4	23	39.7	84.2	3	MI	IV	27
1875	6	18	40.2	84	4.7	FA	VII	85
1876	6		40.4	84.2	3.4	MI	V	102
1877	1	23	38.8	83.5	3.4	FA	III	106
1881	8	30	39.2	83.7	2.9	MI	III	65
1882	2	9	40.4	84.2	3.1	FA	V	102
1884	9	19	40.7	84.1	4.8	FA	VI	137
1884	12	23	40.4	84.2	2.9	MI	III	102
1886	3	1	39	85.5	3	MI	IV	112
1886	6	10	39.34	85.48	2.9	MI	III	98
1889	9		40.4	84.2	2.9	MI	III	102
1892	4	15	40.55	84.57	3.8	MI	IV	120
1895	8	19	38.53	83.75	3.2	FA	III	118
1896	3	15	40.3	84.2	3.1	MI	IV	91
1899	11	12	39.3	83	3.1	MI	IV	118
1901	5	17	38.73	82.99	4.3	FA	VI	145
1902	3	5	38.14	83.76	3.8	MI	IV	158
1902	3	10	39.9	85.2	3	MI	IV	86
1902	3	10	39.9	85.2	3	MI	IV	86

TABLE 6.3.1-I

Earthquakes Within 100 Miles (160 Kilometers) of AK Steel

Year	Month	Day	North Latitude	West Longitude	Magnitude		Intensity (Mercalli)	Radial Distance (km)
1903	1	1	39.9	85.2	2.7	MI	III	86
1903	1	1	39.9	85.2	2.7	MI	III	86
1909	10	22	38.9	84.5	2.5	MI	II	66
1925	3	27	39.8	83.9	3.4	MI	V	52
1925	4	4	39.1	84.5	2.5	MI	II	45
1925	10		40.4	84.2	2.9	MI	III	102
1928	10	27	40.4	84.1	3	FA	III	104
1929	3	8	40.4	84.2	3.7	FA	V	102
1930	6	26	40.5	84	3.2	FA	IV	117
1930	6	27	40.5	84	3.1	MI	IV	117
1930	7	11	40.6	83.2	3.1	MI	IV	158
1930	9	29	40.3	84.2	2.9	MI	III	91
1930	9	30	40.3	84.3	4.2	FA	VII	91
1931	3	21	40.4	84.2	3	FA	III	102
1931	4	1	40.4	84	2.9	MI	III	106
1931	9	20	40.43	84.27	4.7	FA	VII	105
1931	10	9	40.4	84.2	2.9	MI	III	102
1933	2	23	40.4	84.2	3.3	FA	IV	102
1933	5	28	38.6	83.7	3.4	FA	V	114
1936	10	8	39.3	84.4	3.3	FA	III	21
1936	12	26	39.1	84.5	2.9	MI	III	45
1936	12	26	39.1	84.5	2.9	MI	III	45
1937	3	2	40.49	84.27	4.9	FA	VII	112
1937	3	3	40.7	84	3.2	FA	V	138
1937	3	3	40.7	84	2.9	MI	III	138
1937	3	9	40.47	84.28	5.4	FA	VIII	110
1937	4	23	40.7	84	3.1	FA	III	138
1937	4	27	40.7	84	3.1	FA	III	138
1937	5	2	40.7	84	3.1	MI	IV	138
1937	10	17	39.1	84.5	2.9	FA	III	45
1939	3	18	40.4	84	2.5	MI	II	106
1939	3	18	40.4	84	3.3	FA	IV	106
1939	6	18	40.3	84	3.1	FA	IV	95
1939	7	9	40.3	84	2.5	MI	II	95
1944	11	13	40.4	84.4	4.1	FA	III	102

TABLE 6.3.1-I

Earthquakes Within 100 Miles (160 Kilometers) of AK Steel

Year	Month	Day	North Latitude	West Longitude	Magnitude		Intensity (Mercalli)	Radial Distance (km)
1950	4	20	39.8	84.2	3.1	MI	IV	37
1956	1	27	40.5	84	3.7	FA	V	117
1956	1	27	40.4	84.2	3.7	FA	V	102
1957	7	23	38.7	83.8	2.9	MI	III	100
1967	4	8	39.65	82.53	3.7	FA	V	157
1968	7	26	40.43	84.18	3	N/A	III	106
1974	6	5	38.48	84.75	3.2	mbLg	VI	117
1977	6	17	40.57	84.67	3.3	mbLg	VI	123
1980	7	27	38.19	83.89	5.2	mbLg	VII	150
1980	7	31	38.19	83.93	2.5	mbLg	IV	149
1980	8	25	38.19	83.79	2.5	mbLg	IV	152
1980	10	4	39.8	83.75	2	mbLg	N/A	62
1980	12	30	38.2	83.91	3.1	FA	III	148
1983	7	5	40.43	84.1	2.1	mbLg	N/A	107
1986	7	12	40.55	84.39	4.5	mbLg	VI	118
1988	10	22	40.45	84.11	2.2	mbLg	N/A	109
1988	9	7	38.143	83.878	4.6	mbLg	VI	155
1989	7	15	38.606	83.569	3.1	mbLg	V	119
1990	4	17	40.46	84.852	3	mbLg	IV	116
1994	4	4	40.4	84	2.9	mbLg	III	106
1994	7	9	39.045	83.294	2.5	mbLg	III	104
1995	2	19	39.12	83.47	3.6	mbLg	V	86
2004	1	30	40.67	84.62	2.5	mbLg	III	133
2004	9	23	38.317	83.53	2.8	MI	N/A	148
2005	3	13	40.68	84.6	2.2	mbLg	I	134
2006	5	12	40.74	84.08	2.8	mbLg	III	141
2006	8	15	40.71	84.11	2.5	mbLg	I	138
2008	9	30	40.41	84.31	2.8	mbLg	IV	103

TABLE 6.3.1-II
MODIFIED MERCALLI INTENSITY (DAMAGE) SCALE OF 1931
(Abridged)

I. Not felt except by a very few under especially favorable circumstances. (I Rossi-Forel Scale).

II. Felt only by a few persons at rest, especially on upper floors of building. Delicately suspended objects may swing. (I to II Rossi-Forel Scale).

III. Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing of truck. Duration estimated. (III Rossi-Forel Scale).

IV. During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably. (IV to V Rossi-Forel Scale).

V. Felt by nearly everyone, many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbances of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel Scale).

VI. Felt by all, many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VII Rossi-Forel Scale).

VII. Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motorcars. (VIII Rossi-Forel Scale).

VIII. Damage slight in specially designed structures; considerable in ordinary substantial building with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed. (VIII+ to IX Rossi-Forel Scale).

IX. Damage considerable in specially designed structures, well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX+ Rossi-Forel Scale).

X. Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel Scale).

XI. Few, if any, (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.

XII. Damage total. Waves seen on ground surface. Lines of sight and level distorted. Objects thrown upward into the air.

TABLE 6.3.1-III

SEISMIC STATIONS WITHIN GRID BOUNDED BY LONGITUDES 36.5° AND 42.5 °N AND BY LATITUDES 80.5° AND 88.0°W AS OF AUGUST 17, 2011

Code	Location	Latitude	Longitude	Elev. (m)	Network
AAM	Ann Arbor, MI	42.3012	83.6567	172	ANSS
AAMC	Ann Arbor, MI	42.2780	83.7360	250	MICHSEIS
ACEO	Jefferson, OH	41.7387	80.7706	292	OHIOSEIS
ACSO	Alum Creek, OH	40.2323	82.9821	282	ANSS
BCSO	Carroll, OH	39.7941	82.5198	258	OHIOSEIS
BGSO	Bowling Green, OH	41.3794	83.6399	208	OHIOSEIS
BHKY	Lexington, KY	38.0350	84.5050	306	KGS
BHSO	Botkins, OH	40.4690	84.1790	304	OHIOSEIS
BLO	Bloomington, IN	39.1719	86.5222	246	ANSS
CLEO	Cleveland, OH	41.5131	81.6130	205	OHIOSEIS
COWO	Wooster, OH	40.8095	81.9368	328	OHIOSEIS
CSCO	Springfield, OH	39.8956	83.7974	323	OHIOSEIS
ECCO	Piqua, OH	40.1580	84.2115	289	OHIOSEIS
FLKY	Flemingsburg, KY	38.4260	83.7510	280	KGS
GPDO	Montville, OH	41.5831	81.0717	378	OHIOSEIS
HEKY	Henderson, KY	37.8150	87.5920		KGS
ISU	Terre Haute, IN	39.4716	87.4092	148	INDISEIS
KSUO	Kent, OH	41.1510	81.3510	346	OHIOSEIS
LCCO	Kirtland, OH	41.6374	81.3649	244	OHIOSEIS
LECO	Painesville, OH	41.7175	81.2530	204	OHIOSEIS
MOKY	Morganfield, KY	37.6470	87.9010		KGS
MOSO	Butler, OH	40.6115	82.3827	370	OHIOSEIS
MUCO	Alliance, OH	40.9040	81.1106	371	OHIOSEIS
NTLK	Nettle Lake, OH	41.6933	84.7286	293	OHIOSEIS
OGSO	Columbus, OH	40.0568	82.9654	268	OHIOSEIS
OSLO	Lima, OH	40.7375	84.0265	285	OHIOSEIS
OSMO	Mansfield, OH	40.7970	82.5790	397	OHIOSEIS
OSUO	Columbus, OH	39.9981	83.0109	226.1	OHIOSEIS
OUAO	Athens, OH	39.3226	82.0997	194	OHIOSEIS
PKKY	Grayson, KY	38.3830	83.0340	336	KGS
PLIO	Pelee Island	41.7510	82.6280	143	POLARIS
ROKY	Stanton, KY	37.9090	83.9260	433	KGS
SMKY	Sacramento, KY	37.4230	87.2760		KGS
SOKY	Sonora, KY	37.5260	85.9650		KGS
SSUO	Portsmouth, OH	38.7306	82.9931	162	OHIOSEIS

TABLE 6.3.1-III

SEISMIC STATIONS WITHIN GRID BOUNDED BY LONGITUDES 36.5° AND 42.5 °N AND BY LATITUDES 80.5° AND 88.0°W AS OF AUGUST 17, 2011

Code	Location	Latitude	Longitude	Elev. (m)	Network
UOCO	Cincinnati, OH	39.1333	84.5187	266	OHIOSEIS
UTLO	Toledo, OH	41.6594	83.6180	178	OHIOSEIS
WSCO	Celina, OH	40.5467	84.5092	270	OHIOSEIS
WSDO	Dayton, OH	39.7826	84.0633	289	OHIOSEIS
YSUO	Youngstown, OH	41.1043	80.6480	271	OHIOSEIS

ATTACHMENT C

WELL CONSTRUCTION

I. Background and Work Over and Well Repair History (Wells Number 1 and Number 2)

II. Operational Figures

  a. SPL surface facilities

  b. Surface equipment/near wellbore flow configuration

III. Well Diagrams (subsurface)

  a. Well Number 1

  b. Well Number 2

8.0 INJECTION WELL OPERATIONS

Information regarding historic and current construction and operation of the two UIC wells are provided in the following sections. In addition, the most recent demonstration of mechanical integrity and the contingency plan for well failure are discussed.

8.1 Summary

Proper injection well system design is critical to containment and "no-migration" of injected wastes. The design of the two waste injection wells at the AK Steel site has proven to be fundamentally sound through over forty years of successful operation. AK Steel Middletown Works personnel are knowledgeable of the well operations, and trained personnel conduct maintenance on the wells.

The first well was installed in 1967, and the basic design and operational standards are considered to be sound from a regulatory and environmental perspective. Based on successful and safe operation of the wells for this period of time, AK Steel requests that the permits to operate both Class I wells be renewed for a term of six years, as allowed and provided for by OAC Rule 3745-34-21(A).

Both injection wells were of similar construction initially. The primary difference between the wells is a 7" replacement liner from surface to 2933 feet in Well No. 2 that was installed due to damaged 9-5/8" protection casing. In each well, all USDWs are protected with a minimum of two (2) casing strings. All casing strings are cemented from the base to surface with cement that is designed to be compatible with its adjacent subsurface environment and the injection operation. The wells are completed with injection tubing and packers and are monitored on a continuous basis to ensure mechanical integrity at all times. Injection takes place into the deepest sedimentary formation possible. The 2009 three year and 2011 annual mechanical integrity tests continue to demonstrate the integrity of the packer, tubing, and casing and externally by the absence of vertical channels in the primary cement.

The specific construction features common to both wells include:

1) Surface casing
2) Protection casing
3) Injection tubing
4) Wellhead
5) Surface control system

Descriptions of the construction of both existing wells are presented in Section 8.3.

8.2 Background

The two active injection wells are the only Class I injection wells to have been installed at AK Steel. The first well was originally drilled as a test well, and was constructed in 1967. The second well was drilled and completed in 1968. Both wells are currently operated intermittently as needed.

The following sections summarize the history of both wells in chronological order, beginning with the original installation and continuing with each workover. Standard oilfield techniques and procedures were used to drill, complete and work over both wells using materials, where needed, which are matched to the waste being injected.

8.3 Well Construction

The following sections summarize the methods and materials used in the original construction of UIC Wells No. 1 and No. 2. Schematics of each well, illustrating their construction, were included in the 2011 OEPA approved MIT reports. Copies of the schematics are included in the MIT reports located in Appendix 9.1-A.

8.3.1 Underground Injection Control Well No. 1

Drilling of UIC Well No. 1 commenced on February 23, 1967. The well was drilled by Lohmann-Johnson Drilling Company's Rig No. 5. UIC Well No. 1 is located in Lemon Township, Butler County, Ohio. It is situated 1054.6 feet from the north line and 64.7 feet from the west line of the northwest quarter of Section 8. Surface elevation is 658.6 feet above sea level withkelly bushing (KB) at 666.6 feet above sea level. UIC Well No. 1 was drilled to a total depth of 3296 feet KB and is completed in a lower portion of the Eau Claire Formation, the Mt. Simon Sandstone, and the Middle Run Formation utilizing open hole completion techniques. The annulus is fluid filled. Except when the well is out of service for testing, repair or other maintenance, the annulus will be pressured such that at least a 50 psi positive pressure differential will be maintained throughout the length of the tubing string above the packer.

The surface casing is 310 feet of 13 3/8" O.D., 54.5 lb/ft, J-55, short thread and coupling (STC) pipe run in a 17 1/2" hole drilled to 303 feet KB. The surface string was cemented to within eight feet of the surface with 250 sacks of cement. The remaining open annulus was grouted to surface.

The protection casing is 2922 feet of 9-5/8" O.D., 36 lb/ft, J-55, STC pipe run in a 12 1/4" hole drilled to 2922 feet KB. The 9-5/8" protection string was cemented to within 57 feet of the surface. The first slurry of cement pumped down the casing and out the casing shoe was 850 sacks of 50/50 Pozmix cement containing 2% gel and 18% salt. The second slurry consisted of 50 sacks of densified, acid resistant cement. The remaining open annular space was grouted to surface.

The 9-5/8" protection casing was drilled out with an 8-3/4" bit and the open hole interval was drilled to a total depth of 3296 feet KB. During drilling of this well, deviation surveys were conducted at approximately 100 feet to 200 feet intervals to maintain and ensure a vertical hole. The wellbore is essentially vertical with maximum deviations of 1° recorded at depths of 1251 feet, 2167 feet, and 2468 feet.

Selected coring of the Eau Claire Formation and the Mt. Simon Sandstone was conducted to establish porosity and permeability values. A total of 153 feet of core was recovered which included 130 feet of the Mt. Simon Sandstone and 23 feet in the overlying Eau Claire Formation.

The logging program included the following suite of logs: Gamma Ray-Neutron, Compensated Formation Density, Induction Electrical and SP, Continuous Temperature and Sonic. A cement bond log was conducted on the 9-5/8" casing.

The well was originally completed with a 3-1/2" O.D. string of Penton Lined tubing set into a Baker Model "D" permanent packer. A fiberglass tail pipe extended about 73 feet below the packer.

Below the long string casing, injection takes place into an 8-3/4" open hole interval from 2922 feet to 3296 feet KB.

8.3.2 Underground Injection Control Well No. 2

Drilling of UIC Well No. 2 commenced on April 1, 1968. UIC Well No. 2 is located in Lemon Township, Butler County Ohio. It is situated 1190 feet from north line and 1365 feet from west line of the northwest quarter of section 8. Surface elevation is 667 feet above sea level with kelly bushing (KB) at 671 feet above sea level. UIC Well No. 2 was drilled by Burns Drilling Company to a total depth of 3285 feet KB and is completed in the Mt. Simon Sandstone and Middle Run Formation utilizing open hole completion techniques. The annulus is fluid filled. Except when the well is out of service for testing or repair, the annulus will be pressured such that at least a 50 psi positive pressure differential will be maintained throughout the length of the tubing string above the packer.

The surface casing is 299 feet of 13 3/8" O.D., 54.5 lb/ft, J-55, STC carbon steel pipe run in a 17-1/2" hole. The surface string was cemented with 350 sacks of Pozmix cement. Records are not available that indicate whether cement was circulated to the surface; however calculations for the volume of cement pumped and the required annular fillup suggest that circulation was achieved.

The protection casing is 9-5/8" O.D., 36 lb/ft., J-55, STC pipe run in a 12 1/4" hole drilled to 2946 feet KB. The 9-5/8" protection string was run and cemented in three stages. The first stage interval from 2946 feet to 1446 feet was cemented with a lead slurry of 550 sacks of Pozmix cement containing salt and friction reducers. The tail slurry was 50 sacks of densified, acid resistant cement. The second stage was cemented through a stage tool at 1466 feet to the surface with 550 sacks of Pozmix cement containing salt and friction reducers. The third stage was required due to a cement column drop to 414 feet into a lost circulation zone at the Cynthiana-Trenton Contact. The third stage cementing operation utilized 250 sacks of Pozmix containing friction reducer, salt to aid expansion characteristics, and calcium chloride to accelerate curing. No problems were encountered with the third stage cementing operation. A cement bond log, run on April 24, 1968, indicates good bonding across the lost circulation zone (Appendix 4.2.4-B of the 1991 UIC Petition document). The presence of this zone, which is well above the confining zone, has no effect on the waste injection operations.

The protective casing was drilled out with an 8-3/4" bit and the open hole interval was drilled to a total depth of 3285 feet KB. Three 25 foot cores were taken through the Mt. Simon Sandstone. UIC Well No. 2 was originally completed in a similar manner to the UIC Well No. 1 with 3-1/2" Penton lined injection tubing set into a Model "D" permanent packer. A tail pipe composed of three 20 feet sections of 3-1/2" Fibercast tubing was run below the packer.
Below the long string casing injection takes place into an 8-3/4" open hole interval from 2946 feet to 3285 feet KB.

8.4 Construction and Operational Changes of the Waste Disposal Wells

In 1972, the injection tubing of both wells was changed from coated steel to fiberglass. The change was made as a result of several well shutdowns which were caused by cracking of the internal tubing coating and deformation of the Teflon® seal rings at the tubing connections which resulted in tubular failures due to contact of the steel with spent pickle liquor (SPL). A full length 7" liner was cemented inside the 9-5/8" casing of the UIC Well No. 2 the same year due to damage during a workover and corrosion of the casing at the base of the long string. A caliper log, run on August 18, 1972, indicated possible corrosion of the 9-5/8" casing up to 2,670 feet (Appendix 4.2.4-B of the 1990 UIC Petition document). There have been no major problems with these wells since the introduction of the fiberglass tubing. However, the wells are serviced on a periodic basis to redress and inspect the seal assemblies.

In August 1991, a workover was conducted on UIC Well No. 1 as part of the operation to conduct a casing inspection log. During the course of the work, it was determined that the bottom 35 feet of the tailpipe was stuck. The tailpipe was cut off above this point and a new tailpipe was strung into the stuck portion of the old tailpipe via a 2 3/8 inch x 20 foot sub. A new Larkin wellhead was also installed at this time.

A new Larkin wellhead (7" x 3-1/2") was installed on Well No. 2 in August of 1992. The packer and seal assembly in Well No. 2 were replaced in August of 1994 as a routine maintenance operation. The new packer is a Ground Water Protection Systems, Inc. (GPS) Model 12 packer with wetted surfaces constructed from Grade 7 Titanium. The new seal assembly is also constructed of Grade 7 Titanium.

A chronological description of the construction and operational history of UIC Well Nos. 1 and 2 is given below. Included are the major workovers performed on each well. Figures included in the 2011 MIT reports (provided in Appendix 9.1-A) illustrate the current configuration of UIC Well No. 1 and No. 2.

Date	Description
2/23/67	Commenced drilling of UIC Well No. 1.
3/3/67	Completed construction of UIC Well No. 1.
3/2-13/67	Conducted geophysical logs.
4/67-5/67	Conducted initial injection tests into UIC Well No. 1 (Appendix 8.4.0-A).
4/1/68	Commenced drilling of UIC Well No. 2.
4/24/68	Completed construction of UIC Well No. 2. Conducted geophysical logs.
7/8-10/68	Conducted injection tests of UIC Well No. 2 down 9-5/8" casing (Appendix 8.4.0-B).

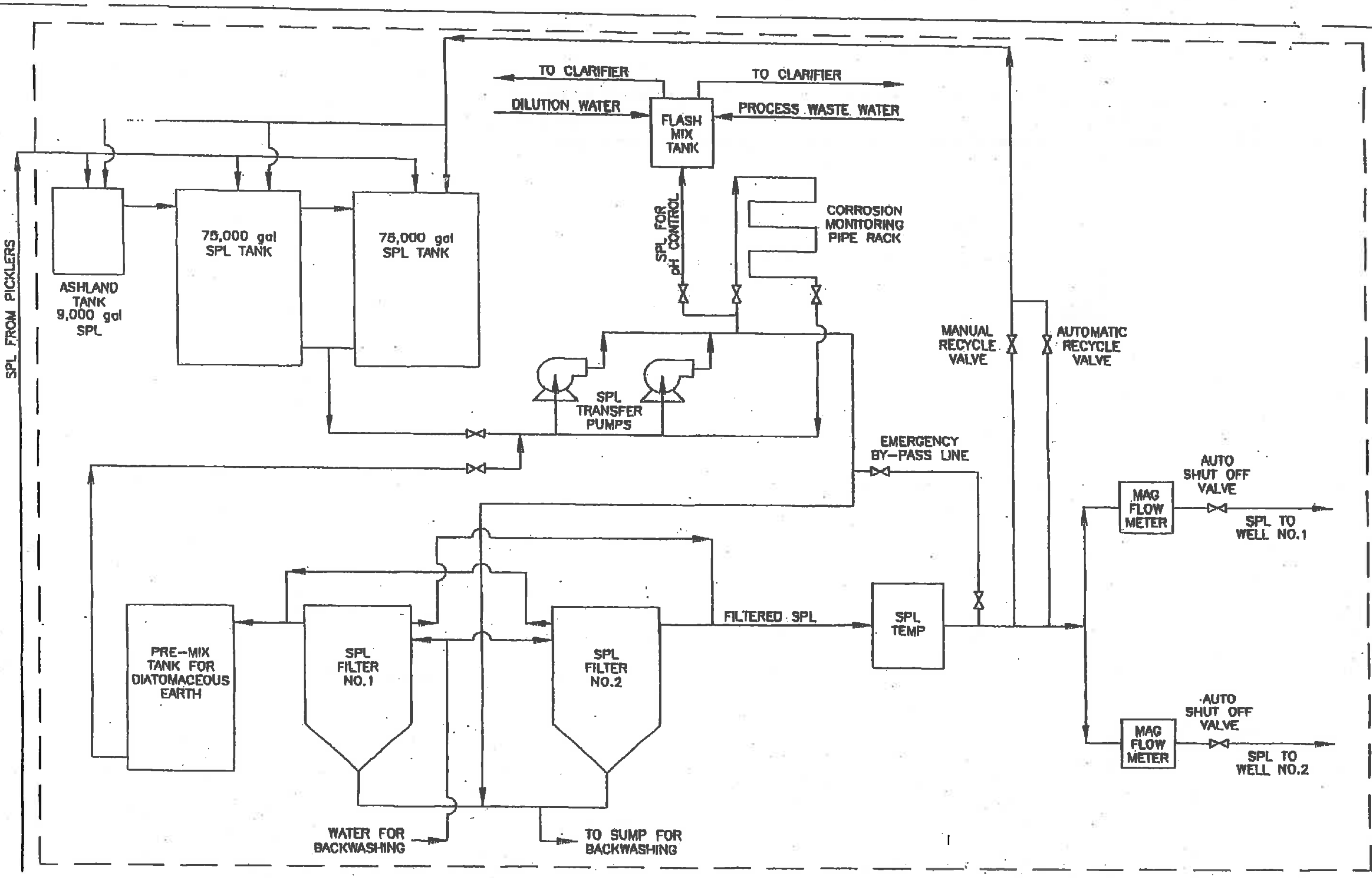
7/68	Installed Penton lined injection tubing and fiberglass tail pipe in UIC Well No. 1.
8/20/68	Installed Penton lined injection tubing and fiberglass tail pipe in UIC Well No. 2.
5/69	Began injection into UIC Well No. 2.
6/69	Began injection into UIC Well No. 1.
7/70-8/70	Loss of annulus pressure in UIC Well No. 1. Experienced packer seal corrosion problems. Seal assembly repaired. Well put back in service with oil buffer below packer.
11/5/70	Installed new Baker Model "D" packer in UIC Well No. 1 at 2875 feet GL (2883 feet KB) with 3-1/2", 9.3 lb/ft, J-55 Penton lined injection tubing with fiberglass tail pipe. Filled annulus with approximately 8000 gallons of mineral oil, plus approximately 500 gallons of oil buffer below packer.
3/72	Loss of annulus pressure in UIC Well No. 1. Hole in injection tubing. Ordered replacement tubing.
4/72	Loss of annulus pressure in UIC Well No. 2. Ran continuous water purge on annulus. Replacement tubing arrived for repair of UIC Well No. 1. A corroded coupling was found at 220 feet. Ran casing caliper log and set new packer at 2854 feet GL, (2862 feet KB). Put UIC Well No. 1 in service and shut down UIC Well No. 2.
5/72	Lost annulus pressure in UIC Well No. 1 due to corroded coupling in Penton lined injection tubing at 330 feet and 1650 feet. Used materials ordered for UIC Well No. 2 to repair UIC Well No. 1.
6/72	Reassembled UIC Well No. 1 with (unknowingly) excessive thread lubricant on

	tubing couplings. Research tests proved grease would deform teflon coupling rings causing injection tubing to fail at threaded connections. Disassembled well and removed excess lubricant. Reassembled well (with Penton and Kynar coated tubing) and put back in service. Lost annulus pressure and placed continuous water purge on annulus. Started disassembling UIC Well No. 2. Injection string parted and fell downhole. Fished injection tubing in UIC Well No. 2 down to a depth of 2200 feet. Moved in rotary rig to mill out balance of injection string to bottom of 9-5/8" casing.
7/72	Disassembled UIC Well No. 1. Found seal assembly had parted. Logged casing and set new packer at 2842 feet GL, (2850 feet KB). Place UIC Well No. 1 back in service.
8/72	Started milling out bottom of UIC Well No. 2 with rotary rig. Cleaned out hole, logged casing. Ran 7" liner inside 9-5/8" casing, to 2933 feet and cemented to surface on 8/26/72. Conducted cement bond log and set new Baker Model "F - 1" packer at 2916 feet GL. Lost annulus pressure on UIC Well No. 1 and took well out of service. Pulled UIC Well No. 1 injection tubing and found hole in body of a joint of tubing from a depth of 300 feet. Replaced joint, reassembled well and restored well to service.
9/72	Lost annulus pressure on UIC Well No. 1. Took well out of service while waiting on repair materials. Conducted cement bond and caliper logs of 7" casing in UIC Well No. 2. Reset packer in UIC Well No. 2 at 2916 feet GL.
10/72	Reassembled UIC Well No. 2 with Fibercast injection tubing. Pulled injection tubing from UIC Well No. 1 and replaced KYNAR coated steel with Fibercast tubing.

11/15/72	Fibercast injection tubing in use in both wells with 60 feet of fiberglass tail pipe beneath packer in each well. Thirty weight motor oil emplaced behind tail pipe of both wells to serve as corrosion barrier.
9/9-18/75	Pulled tubing and seal assembly from UIC Well No. 2. Replaced seal assembly and tail pipe. New seal assembly had nine seal units. Returned well to service.
5/9-25/76	Pulled tubing and seal assembly from UIC Well No. 2. Redressed seal assembly and reassembled well. Returned well to service.
5/4-31/78	Pulled tubing and seal assembly from UIC Well No. 1. Redressed seal assembly with combination Viton and HyCar seals. Reassembled well. Returned well to service.
8/1-27/79	Pulled tubing and seal assembly from UIC Well No. 1. Replaced six sections of seal assembly due to damaged coating. Reran ten-section coated seal assembly dressed with combination Viton and HyCar seals and a six-section centralized fiberglass tail pipe. Filled annulus with inhibited fresh water and topped with 500 gallons of oil. Returned well to service.
7/10-30/81	Pulled tubing and seal assembly from UIC Well No. 1. Redressed seal assembly and reassembled well with inhibited Freshwater and 170 barrels of oil in annulus. Returned well to service.
8/5-30/91	Attempted to pull tubing from UIC Well No. 1, and determined that the bottom 35 feet of 3-1/2" tailpipe was stuck. The 3-1/2" tailpipe was cut above the stuck portion and removed from the well along with the packer seal assembly. Installed new packer seal assembly. Replaced old national wellhead with new 7" x 3-1/2" Larkin wellhead. Reassembled well with fresh water containing corrosion inhibited sodium

	sulfite and biocide and 220 gallons of oil in annulus. Returned well to service.
8/10-17/92	Pulled tubing and seal assembly from UIC Well No. 2. Installed new packer seal assembly. Reassembled well. Installed new Larkin wellhead. Filled annulus with inhibited fresh water with a biocide. Oil was spotted to act as a fluid buffer below the packer.
6/20-30/94	Pulled tubing and seal assembly from UIC Well No. 1. The 3-1/2" tubing was inspected, and seven joints were rejected and replaced. The seals on each of the 11 individualized seal assembly units were replaced with Baker V-Ryte type seals. The steel, internally coated, landing joint was also replaced. Reassembled well with fresh water containing a corrosion inhibitor and biocide and 130 gallons of oil in annulus. Returned well to service.
7/30/94 - 8/16/94	Pulled tubing and seal assembly from UIC Well No. 2. The Baker permanent packer was milled and pushed into the open hole portion of the wellbore. A Ground Water Protection Systems, Inc. (GPS) Model 12 packer with wetted surfaces constructed from Grade 7 Titanium was installed. The injection tubing assembly was run into the well consisting of four joints of 2-7/8" Fibercast epoxy tailpipe, GPS Grade 7 Titanium seal assembly, 97 joints, and 2 pup joints of 3-1/2" Tubular Fiberglass epoxy tubing. The annulus fluid was changed from fresh water to brine. Reassembled well with 115 barrels of 10 ppg NaCl brine containing an oxygen scavenger and biocide and 66 gallons of oil for freeze protection.
04/23/98-05/07/98	Conducted acid stimulation of UIC Well No. 2 in two stages. Stage 1 included pumping 3,000 gallons of 28% hydrochloric acid (HCl) into the well, which was left in the openhole and near wellbore area overnight. The well was returned to injection the next day. Thirteen (13) days

	later, Stage 2 was conducted by pumping 5,000 gallons of 15% HCl and 10,000 gallons of 12% HCL + 3% hydrofluoric acid (HF) via 1 ¼ inch outside diameter coiled tubing placement. The 15% HCl stimulation mixture included 2 gallons per thousand-gallon (gpt) inhibitor, 4 gpt surfactant, and 18 gpt iron sequesterant. The 12% HCl + 3% HF mud acid contained 2 gpt inhibitor, 4 gpt surfactant, and 18 gpt iron sequesterant. The coiled tubing was run between 2980-3150 feet. The mud acid treatment was followed by injection of 5,754 gallons of brine containing 2 gpt of surfactant to displace oils.
06/23/99-06/25/99	Conducted acid stimulation of UIC Well No. 1 via coiled tubing in three (3) stages. Stage 1 included 2,500 gallons of 15% HCl with 18 gpt iron control agent, 4 gpt surfactant and 2 gpt corrosion inhibitor was injected. Stage 2 included a mud acid treatment, pumping 10,000 gallons of 10% HCL + 6% HF with 18 gpt iron control agent, 4 gpt surfactant and 2 gpt corrosion inhibitor. Stage 3 included pumping 2,500 gallons of 15% HCL with 18 gpt iron control agent, 4 gpt surfactant and 2 gpt corrosion inhibitor. Acid stimulation was followed by 8,000 gallons of displacement 9.7 pounds per gallon (ppg) brine through the tubing.
02/04/11-02/06/11	Conducted acid stimulation of UIC Well No. 1 via coiled tubing in 3 stages. The first stage consisted of 2,460 gallons of 15% HCl with 45 gallons of iron control agent, 10 gallons of surfactant, and 5 gallons of corrosion inhibitor. Stage 2 included 9,840 gallons of mud acid (12% HCl and 6% HF), with 180 gallons of iron control agent, 40 gallons surfactant, and 20 gallons of corrosion inhibitor. Stage 3 included 2,460 gallons of 15% HCl with 45 gallons of iron control agent, 10 gallons of surfactant, and 5 gallons of corrosion inhibitor. The stimulation fluids were displaced into the injection formation with 11,634 gallons of 10 ppg brine through the 3 ½" tubing.



ALL EQUIPMENT INSIDE DASHED LINE IS INSIDE CONTAINED AREA WITH SUMPS

SUBSURFACE

HOUSTON, TX.
SOUTH BEND, IN.
BATON ROUGE, LA.

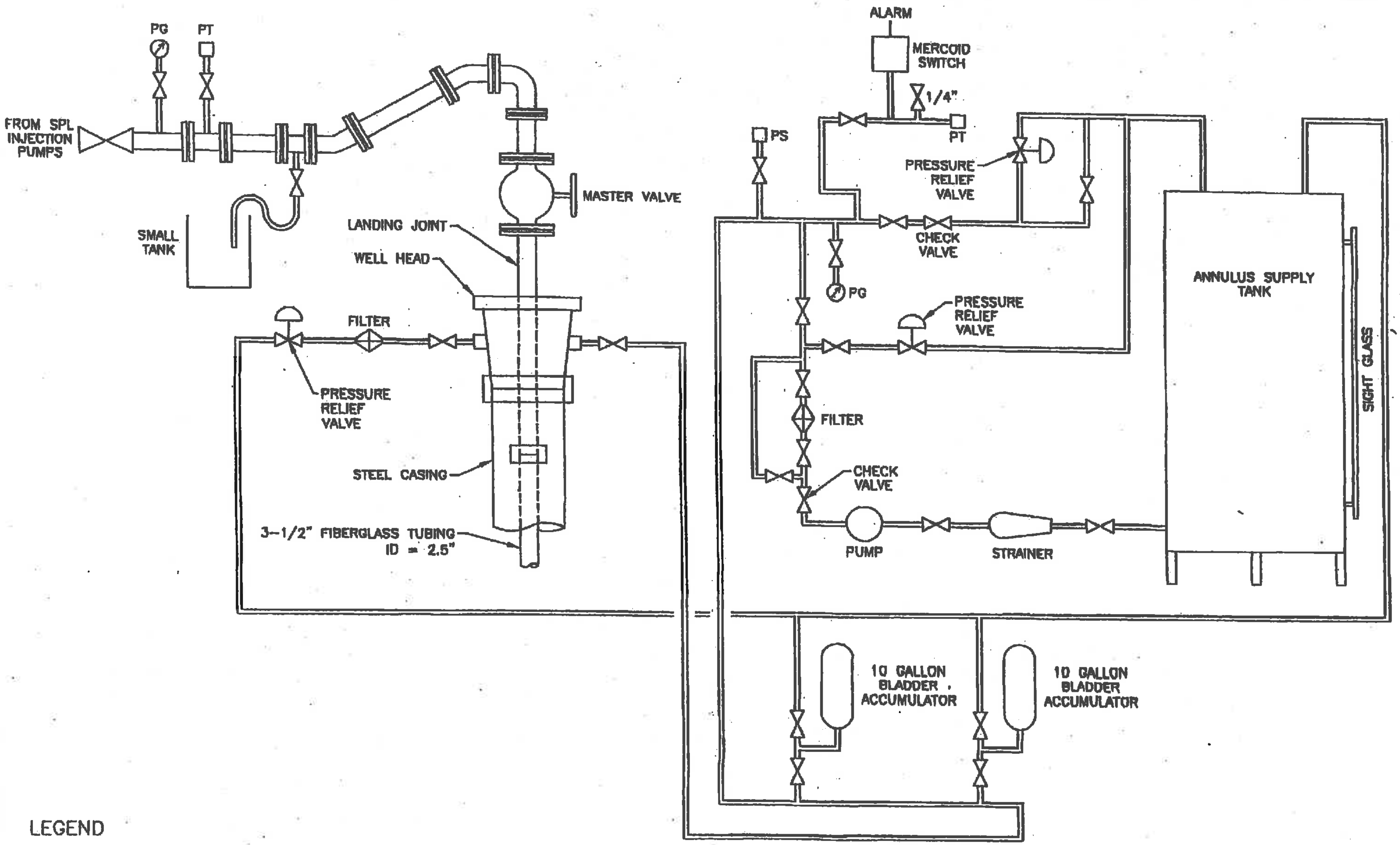
DATE: 9/30/02	CHECKED BY: DWJ	JOB NO: 60D5382
DRAWN BY: CRB	APPROVED BY:	DWG. NO:

FIGURE 3.2-1

AK STEEL CORPORATION

MIDDLETOWN, OHIO

SCHEMATIC OF SPENT PICKLE LIQUOR SURFACE FACILITIES



LEGEND

PG	PRESSURE GAUGE
PT	PRESSURE TRANSMITTER
PS	PRESSURE SWITCH
⋈	VALVE

SUBSURFACE

HOUSTON, TX.
SOUTH BEND, IN.
BATON ROUGE, LA.

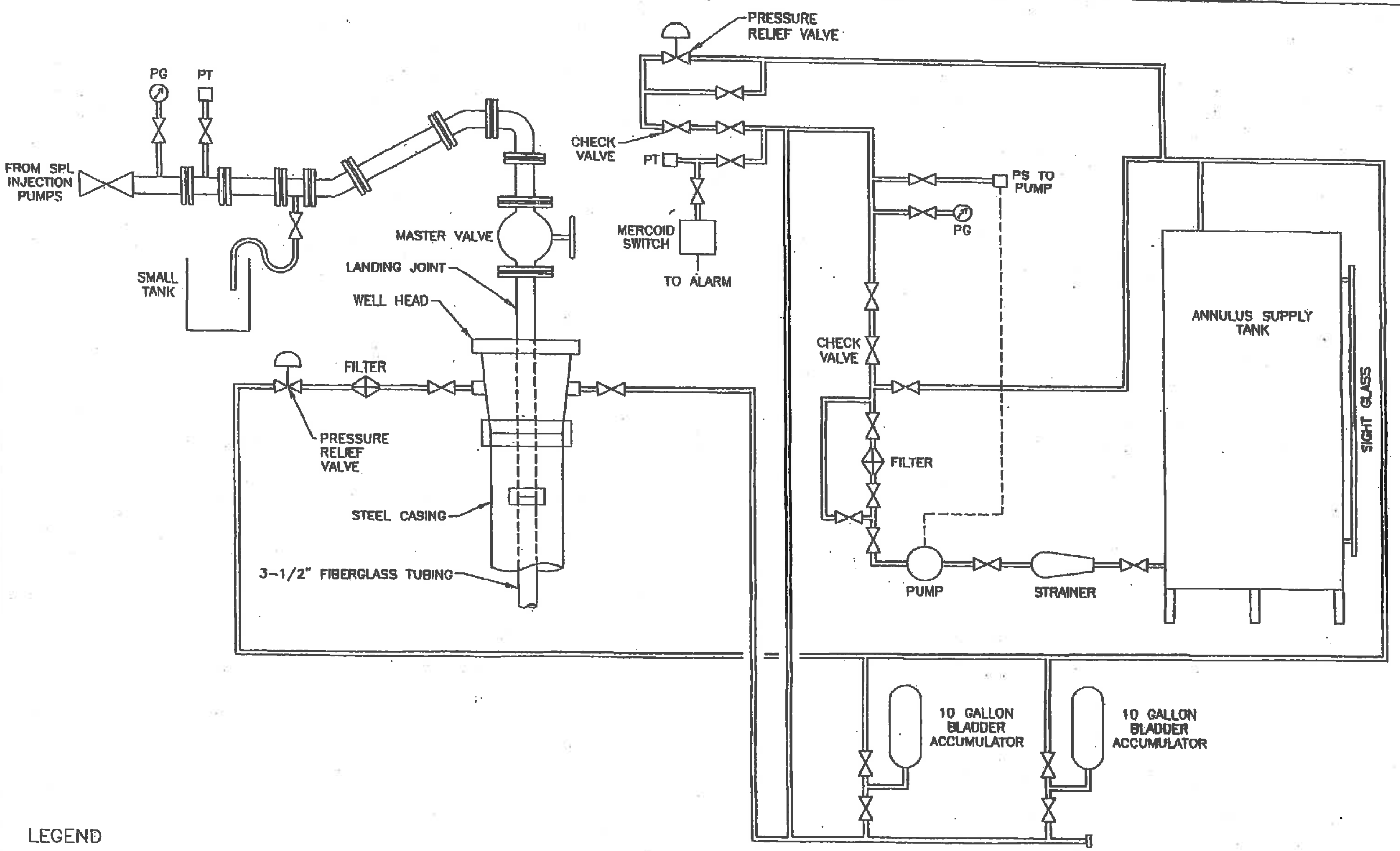
DATE: 9/30/02	CHECKED BY:	JOB NO: 60D5382
DRAWN BY: CRB	APPROVED BY:	DWG. NO:

FIGURE 3.2-2

AK STEEL CORPORATION

MIDDLETOWN, OHIO

SCHEMATIC OF UIC WELL NO.1
SPENT PICKLE LIQUOR SURFACE FACILITIES



LEGEND

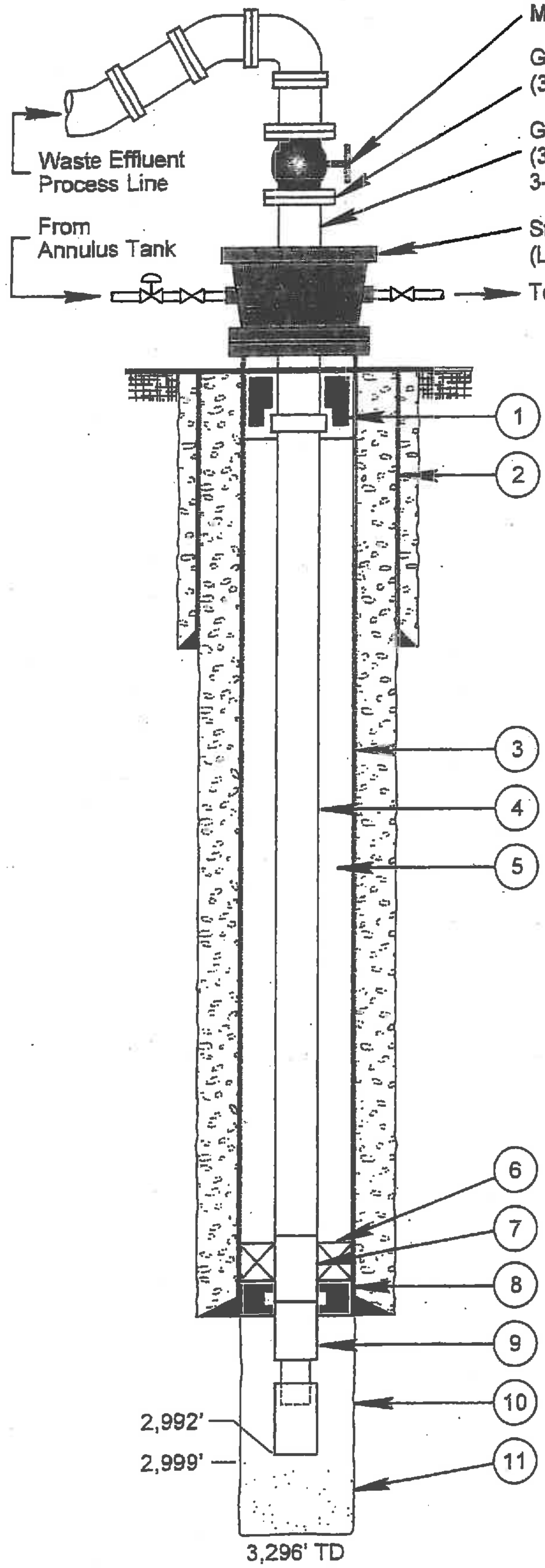
PG	PRESSURE GAUGE
PT	PRESSURE TRANSMITTER
PS	PRESSURE SWITCH
⋈	VALVE

SUBSURFACE

HOUSTON, TX.
SOUTH BEND, IN.
BATON ROUGE, LA.

DATE: 9/30/02	CHECKED BY:	JOB NO: 6005382
DRAWN BY: CRB	APPROVED BY:	DWG. NO:

FIGURE 3.2-3
AK STEEL CORPORATION
MIDDLETOWN, OHIO
SCHEMATIC OF UIC WELL NO.2
SPENT PICKLE LIQUOR SURFACE FACILITIES



1. Oil (Annulus Fluid-Upper) approximately 6 barrels for freeze protection
2. Surface Casing: 13-3/8" O.D., 54.5 lb/ft., J-55, STC carbon steel set to 303' in 17-1/2" hole and cemented to surface with 250 sacks cement
3. Protection Casing: 9-5/8" O.D., 36 lb/ft., J-55, LTC carbon steel set to 2,923' in 12-1/4" hole and cemented to surface with 850 sacks of 50/50 POZMIX (w/2% GEL and 18% salt) and 50 sacks densified acid resistant cement
4. Injection Tubing: 3-1/2" O.D., Fibercast
5. Annulus Fluid with 9.7 ppg brine water & 1.0% of Tretolite CRW0132F containing; Corrosion inhibitor, Biocide and oxygen scavenger
6. Model "D" Packer set at 2,855' KB, additional Model "D" Packers set at: 2,869' KB, 2,887' KB & 2,920' KB
7. Seal Assembly - 3 Seals, 6.15' Long (Grade 7 Titanium)
8. Oil (Fluid buffer below packer)
9. Tailpipe: 3-1/2" Fibercast; 92.91' Long and 1 joint of 2-3/8" Fibercast; 20.20' Long Stung into 36' of 3-1/2" Fibercast which is stuck
10. Open hole completed in Mt. Simon, Drilled 8-3/4" O.D., from 2,923' to 3,296'
11. Top of fill and/or bridge

Note: All depths are referenced to KB based on Gamma Ray-Collar Log dated August 24, 1991.

GL Elevation - 658.6'
KB Elevation - 666.6'

Injection Zone: 2,423' to 3,296'
Injection Interval: 2,900' to 3,296'

AK Steel

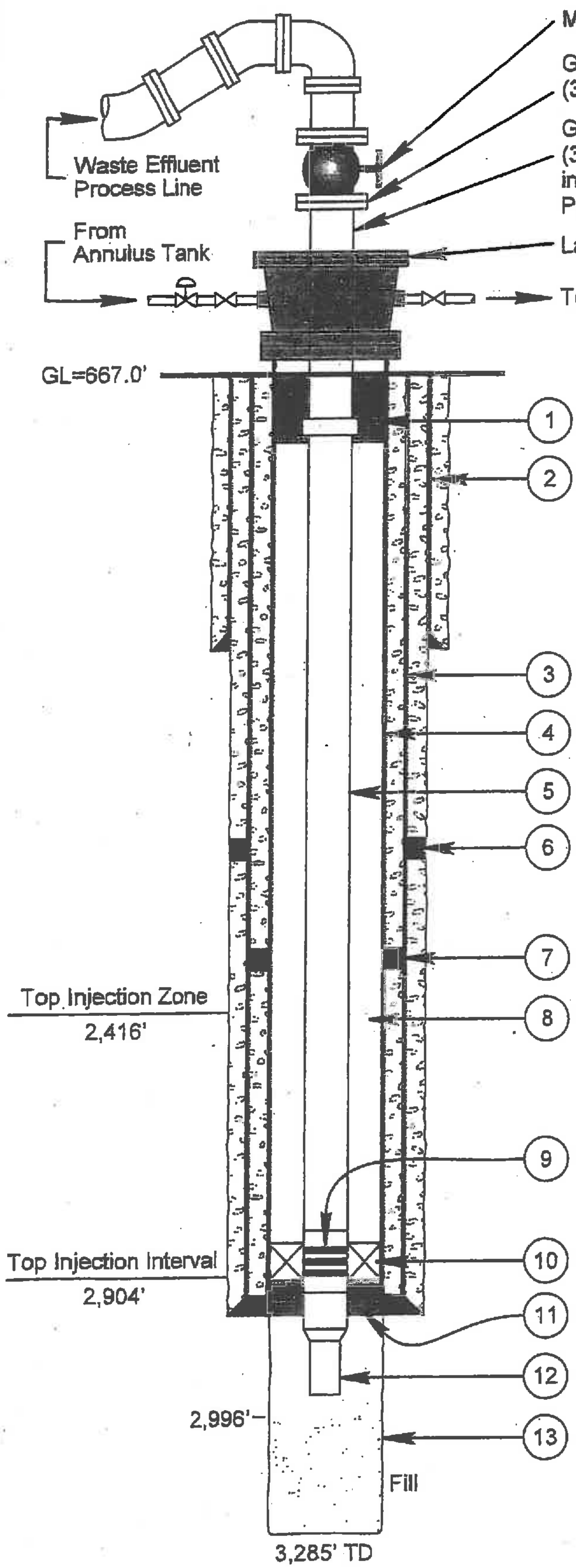
AK Steel Corporation Middletown Works

Figure 1
Underground Injection Control
Well No. 1 Schematic
2012 MIT Report

Scale: NTS	Date: July 2012
2012_AKS_Well No.1_Sch.ai	By: JLM — Checked: KC

Petrotek — Kemron Environmental Services

Well Construction current per AK Steel records as of June, 2009



1. Oil (Annulus Fluid-Upper) approximately 4 barrels for freeze protection
2. Surface Casing: 13-3/8" O.D., 54.5 lb/ft., J-55, STC carbon steel set to 299' in 17-1/2" hole and cemented to surface w/ 350 sacks Pozmix cement
3. Protection Casing: 9-5/8" O.D., 36 lb/ft., J-55, LTC carbon steel set to 2,946' in 12-1/4" hole and cemented to surface with 1,350 sacks of Pozmix cement with salt and friction reducer
4. Liner: 7" O.D., 26 lb/ft., carbon steel, installed 8/72 to 2,933' and cemented to surface
5. Injection Tubing: 3 1/2" tubular fiberglass epoxy-2,000 psi rating (8rd threads)
6. 9 5/8" Stage Cementing Tool at 1,466'
7. 7" Stage Cementing Tool at 2,610'
8. Annulus filled with 10 ppg NaCl brine with Biocide (Kathon 886MW) and Oxygen scavenger (Sodium Sulfite)
9. Grade 7 Titanium Locator type seal assembly with 3 seal units. Ten graphite filled teflon seals w/ a Viton center ring per seal unit.
10. GPS Model 12 Packer-Wetted surfaces are grade 7 Titanium. Packer set at 2,900' GL, 2,904' KB
11. Oil (Fluid buffer below packer)
12. Tailpipe: 2 7/8" Fibercast, 77.64' with Muleshoe
13. Open hole completed in Mt. Simon, Drilled 8-3/4" O.D., from 2,946' to 3,285'

GL Elevation - 667'
KB Elevation - 671'

Injection Zone: 2,416' to 3,285'
Injection Interval: 2,904' to 3,285'

Note: 1. Casing depths and open hole depths are to KB.
Tubing and packer depths were referenced from GL and corrected to KB.

2. Well Construction current per AK Steel records as of June, 2009

AK Steel

AK Steel Corporation
Middletown Works

Figure 1
Underground Injection Control
Well No. 2 Schematic
2012 MIT Report

Scale: NTS	Date: July 2012	
2012_AKS_Well No2_Sch.ai	By: JLM	Checked: KC

Petrotek
KEMRON ENVIRONMENTAL SERVICES

ATTACHMENT D

OPERATING, MONITORING AND REPORTING REQUIREMENTS

	LIMITATION	MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
Characteristic	Maximum	Frequency	Frequency
* Injection Pressure	Up to 618 psi and as limited in Part II (C)(2) of this permit	^continuous	monthly
** Bottom hole Pressure	2175 psi	daily maximum	monthly
*** Injection Rate	≤ 60 gpm combined Monthly average	continuous	monthly
**** Annulus Pressure	≥50psi differential	continuous	monthly
+ Specific Gravity	1.24	Daily	monthly
Cumulative Volume	N/A	continuous	monthly

Annulus Sight Glass Level		daily	monthly
Injectate Temperature		continuous	monthly
++.Chemical Composition of Injected Fluid		quarterly	quarterly

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

0.75 = applied fracture gradient in psi/ft
1.24 = fluid specific gravity
2900 = depth to the top of the injection interval in feet
.433 = pressure gradient of fresh water

Pressure Gradient of Injectate = (1.24 X .433) = .53692 psi/ft

MASIP = (.75 X 2900) - (.53692 X 2900) = 618 psi (Current MASIP = 100psi) or as specified in the most current Ohio EPA approved UIC Monitoring Plan.

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

BHP_{max} = (.75 X 2900) = 2175 psi

^ Continuous Monitoring: For the purpose of this permit, the required continuous monitoring equipment shall yield data of the required parameters at a frequency of five seconds.

***Injection Rate: Combined monthly average flow rate for both wells must be ≤ 60 GPM. or as otherwise approved in the most current USEPA Landban Exemption.

****Annulus Pressure Requirement: The pressure on the annulus shall be maintained continuously at ≥50 psi higher than the injection pressure throughout the entire length of the tubing.

+Specific Gravity: Specific gravity (S.G.) of the injectate shall be monitored and recorded daily. The daily measurement shall be reported monthly. As the S.G. measurement increases above 1.24 the maximum allowable injection pressure measured at the well head shall be adjusted downward accordingly such that a bottom hole pressure of 2175 psi is not exceeded.

++Quarterly Waste Analysis: Chemical analysis of the injectate shall be conducted quarterly for, at a minimum, the waste constituents listed in Part II (D)(2) of this permit and in accordance with the Waste Analysis Plan approved by the Director.

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 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 05-09-001-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.

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Date

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Authorized Agent Signature

For ____________________________
Name of Company