AEC Gas Gathering System

Integrity Management Plan

Horseheads, New York

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GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT PROGRAM

AEC GAS GATHERING SYSTEM
HORSEHEADS, NY

REVISION 0 – OCT. 15, 2010

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1.0 Introduction

AEC is a producer of indigenous natural gas whose natural gas activities in New York are limited to those specified in Public Service Law § 66-g(3) and, thus, AEC is subject to limitations on the jurisdiction of the commission as set forth therein. Anschutz Exploration Corp. (AEC) has developed a comprehensive, systematic and integrated management system that ensures the integrity of the facility's natural gas pipeline. The system assists the facility in identifying, assessing and mitigating potential threats to the pipeline and provides a process for continual integrity assessment and system improvements to ensure ongoing pipeline safety. This written Integrity Management Program (IMP) describes the implementation of this management system for each program element. The IMP also describes the requirements and site procedures related to the inspection, testing, and assessment and mitigation of risks related to the site's pipeline. As IMP information and experience is gathered and analyzed, its incorporation into the program results in a more detailed understanding of the pipeline condition and a more comprehensive IMP.

1.1 System Description

The AEC gas gathering system consists of two (2) 4-inch pipeline sections, two (2) 6-inch pipeline sections and one (1) 12-inch pipeline section. The 4-inch pipelines extend from two separate points of origin and both tie into a section of the reinstated 12-inch A-5 Pipeline, formerly operated by Columbia Gas Transmission Corporation, at two distinct locations. One 4-inch pipeline extends 1,273-feet from Ruger #1 Well (Ruger) (API #31-015-26304-00) located in the Town of Horseheads, approximately 750 feet southeast of New York State Route 13, about 175 feet north of a NYSE&G Right-of-Way and connects with the A-5 Pipeline just southeast of where it crosses beneath New York State Route 13. The second 4-inch pipeline commences from a well located on the east side of the Center at Horseheads complex (CAH) (API #31-015-26196-00) located in the Village of Horseheads, and traverses north-northeasterly 4,549-feet to a connection point southwest of the intersection of Wygant Road and Ridge Road. The 6-inch pipelines extend from the 12-inch A-5 pipeline at a point 25 feet (inlet pipe) and 70 feet (outlet pipe) west of Hickory Grove Road at the existing custody transfer site. The 6-inch inlet pipe to the proposed metering and regulating facility extends 27-feet north from the A-5 pipeline to the fence of the proposed metering and regulating facility. The 6-inch outlet pipe extends 30-feet south from the proposed metering and regulating facility fence back to the A-5 pipeline. The gas gathering system also includes a 2.7 mile section of the A-5 pipeline from New York State Route 13 to Hickory Grove Road. The Project lies within the Village of Horseheads and Town of Horseheads, Chemung County, New York. The A-5 pipeline and routes of the CAH and Ruger Lines are overlain on an aerial photograph provided in Figure 1. The proposed pipeline routes are shown on the topographic maps identified as Figure 2.

AEC has received a "Certificate of Environmental Compatibility and Public Need" (Case 09-T-0865, Feb. 8, 2010) for the construction, operation, and maintenance of two (2) underground natural gas transmission pipelines constructed of nominal 4-inch diameter, ERW, Grade B carbon steel pipe, coated, cathodically protected, and buried approximately 36-inches (typical) deep and two (2) underground natural gas transmission pipelines constructed of nominal 6-inch diameter, ERW, Grade B carbon steel pipe, coated, cathodically protected, and buried approximately 36-inches (typical) deep. The transmission pipelines will typically operate at 1200 pounds per square inch gauge (psig) with a certified maximum allowable operating pressure (MAOP) of 1235 psig for the 12-inch diameter and 6-inch diameter portions of the pipeline and 1300 psig for the 4-inch diameter portions of the pipeline.

1.2 Regulatory Structure

This IMP has been prepared by AEC to conform to the requirements set forth in 16 NYCRR Part 255.901 and was drafted using guidance provided by the USDOT Office of Pipeline Safety Gas Integrity Management Inspection Manual Inspection Protocols and American National Standard ASME B31.8S-2004, Managing System Integrity of Gas Pipelines. Where non-mandatory standards and best practices exist, it is the policy of AEC to address these non-mandatory statements on a case-by-case basis and they will be considered mandatory unless the facility determines that they are not practicable.

1.3 Roles and Responsibilities

The AEC Operations Manager maintains overall leadership responsibility for all aspects of facility operation, including implementation of the IMP and the Part 255 requisite pipeline Operating and Maintenance Plan (O&M Plan). Any deviations from the policies and procedures outlined in these programs are reviewed with the operation field staff or other appropriate designee. Administration and record keeping associated with AEC's IMP is managed within AEC's systems both on-site and in their offices in Denver, CO. Specific maintenance operations, tests and investigations are performed by AEC facility personnel and/or qualified contract service companies.

Roles and Responsibilities are shown on Table 1.1

1.4 Site Certifications

The AEC facility is operated and maintained in accordance with the NYCRR 16, Part 255.

1.5 Personnel Qualification

AEC has developed and implemented a written Operator Qualification program that details minimum requirements for operators' qualification to perform covered tasks. The AEC Operator Qualification Program is incorporated as Attachment 3 of this document.

AEC Gas Gathering System – Horseheads, NY Integrity Management Program Table 1.1 – Roles and Responsibilities				
Task Name	**Tool**	**Category**	**Responsible Person**	**Qualifications**
• Responsible for IMP Program • Provides support and resources • Monitors program performance		Review	Operations Manager (Jim Oursland)	Knowledge of or training received on the requirements of NYCRR 255.901
• Ensures compliance to time table set by codes • Ensures quality of assessments • Ensures appropriateness of assessment findings • Ensures actions taken are responsive to findings	NYCRR 255.915(a)	Review	Subject Matter Expert (John Heintz, PE)	• BS degree in engineering or other suitable education or experience • Knowledge of or training received on the requirements of NYCRR 255.901 • Knowledgeable in the design and repair of gas transmission pipelines
Conducts Integrity Assessment	NYCRR 255.915(b)(1)	Review and Documentation	Maintenance Supervisor (Greystar) Subject Matter Expert (John Heintz, PE)	• BS degree in engineering or other suitable education or experience • Knowledge of or training received on the requirements of NYCRR 255.901 • Knowledgeable in the design and repair of gas transmission pipelines

Reviews and analyzes results from integrity assessment or evaluation	NYCRR 255.915(b)(2)	Review and Documentation	Maintenance Supervisor (Greystar) Subject Matter Expert (John Heintz, PE)	• BS degree in engineering or other suitable education or experience • Knowledge of or training received on the requirements of NYCRR 255.901 • Knowledgeable in the design and repair of gas transmission pipelines
Makes decisions on actions to be taken based on integrity management assessments	NYCRR 255.915(b)(3)	Review and Documentation	Maintenance Supervisor (Greystar) Subject Matter Expert (John Heintz, PE)	• BS degree in engineering or other suitable education or experience • Knowledge of or training received on the requirements of NYCRR 255.901 • Knowledgeable in the design and repair of gas transmission pipelines
Supervise excavation work carried out in conjunction with integrity assessment	NYCRR 255.915(c)(2)	Documentation	Task Supervisor (Persons responsible for preventative and mitigative measures)	• High school degree or equivalent • Experience in operating and maintaining gas transmission pipelines • Familiarity with NYCRR 255.901
Implements preventive and mitigative measures (marking and locating, ROW surveys, signage, cathodic protection, etc)	NYCRR 255.915(c)(1)	Documentation	Task Supervisor (Persons responsible for preventative and mitigative measures)	• High school degree or equivalent • Experience in operating and maintaining gas transmission pipelines • Familiarity with NYCRR 255.901

2.0 High Consequence Areas Identification

The AEC gas gathering system is supplied by two conventional gas wells, Center at Horseheads #1 (CAH) & Ruger #1 (Ruger). The well head facilities are designed to flow 20 MMscfd (14 MMscfd from CAH and 6 MMscfd from Ruger) into the Millennium Pipeline Company (MPC) system through the Hickory Grove Measurement Station.

The CAH system consists of well head facilities and approximately 4,550 feet of 4-inch pipe. The Ruger system consists of well head facilities and has approximately 1,280 feet of 4-inch pipe. Both well lines are connected to a 12-inch pipeline leased by AEC from MPC. There are two sections of 6-inch pipe that tie the 12-inch pipeline to the M&R station located at Hickory Grove Road. The 6-inch pipelines extend from the 12-inch A-5 pipeline at a point 25 feet (inlet pipe) and 70 feet (outlet pipe) west of Hickory Grove Road at the existing custody transfer site. The 6-inch inlet pipe to the proposed metering and regulating facility extends 27-feet north from the A-5 pipeline to the fence of the proposed metering and regulating facility. The 6-inch outlet pipe extends 30-feet south from the proposed metering and regulating facility fence back to the A-5 pipeline.

The 12-inch pipeline is a 2.7 mile section of MPC's A-5 Pipeline that had been out of service since February 2009. AEC re-commissioned and re-activated this section in March 2010. The gas flows east to west into the MPC system. The entire pipeline system is located in either a class 1 or 2 location by definition.

NYCRR 16 Part 255.901 through 255.951 prescribes the minimum requirements for an integrity management program for gas transmission pipelines. AEC used these parts in its determination for the identification of high consequence areas (HCA's) located along the route for the 12-inch, 6-inch and 4-inch pipelines.

By the calculation for determining the potential impact radius (PIR) as stated in 255.903 (3) (i), AEC concluded the following:

- PIR for 12" – 290 feet
- PIR for 6" – 146 feet
- PIR for 4" – 100 feet

2.1 Potential Impact Radius

The AEC natural gas transmission pipeline system operates with a maximum allowable operating pressure of 1235 psig in the 12-inch and 6-inch diameter sections and 1300 psig in the 4-inch diameter sections.

The potential impact radius is therefore calculated to be:

$$r = 0.69 * d \sqrt{p}$$

where,

d = outside diameter of the pipeline, in.
p = pipeline segment’s maximum allowable operating pressure, psig
r = radius of the impact circle, ft

12-inch section

$r = 0.69 * 12 * \sqrt{1235}$

$r = 290$ feet

6-inch section

$r = 0.69 * 6 * \sqrt{1235}$

$r = 146$ feet

4-inch section

$r = 0.69 * 4 * \sqrt{1300}$

$r = 100$ feet

Although the PIR for the 12” was calculated at 290 feet, the 660 foot buffer was chosen since the pipeline was an existing system, previously installed, owned and operated by another company and details available regarding the integrity of the entire pipeline system could not be confirmed in an economically feasible manner. The 12” pipeline was re-commissioned by hydro-test prior to being put back into service under AEC operation.

The 4” CAH well line which is attached to the 12” A-5 has a PIR of 100 feet. However, in areas where the 4” line is located within the 660 foot buffer zone associated with the 12” A-5 line, it was determined that these locations would be considered an HCA. Approximately 3,800 feet of the CAH line is located with the 660 foot buffer of the A5 pipeline. Consequently that segment of the CAH line is considered an HCA.

The 4” Ruger well line is also attached to the 12” A-5 pipeline and has the same PIR of 100 feet. It does not encroach within the limits of the 660 foot buffer zone of the A5. There are no structures within the 4” 100 foot buffer zone, thus it was determined that the Ruger 4” well line is not within an HCA.

The 6” section of pipeline at the Hickory Grove M&R Facility is not within an HCA.

Please refer to drawings 45789001 and 45789002 attached as HCA documentation drawings.

2.2 Identified Sites

The facility HCA assessment reviewed the location of the pipeline, information from historical pipeline facility inspections and patrols, and satellite imagery of the transmission pipeline route. AEC personnel also reviewed pipeline survey and maintenance records, aerial photography of the area surrounding the facility and pipeline, results from previous neighborhood surveys, roadside surveys of the area adjacent to the pipeline and other pertinent data to identify the location and surrounding usages of the pipeline to asses the HCA. Based on the Subject Matter Expert (SME) review the areas shown on the drawings in Figure 3are the only §255 identified sites delineated. This determination was drawn from the fact that there are no other buildings or outside meeting areas that meet the criteria in 192.903 for identified sites.

2.3 Newly Identified HCAs

AEC employs many processes that would identify changes in the defined HCA or would identify a new HCA, if one were to be established. The Maintenance Supervisor will be responsible for training appropriate AEC personnel in developing an awareness of new HCAs along the pipeline and recognizing potential threats. Routine facility inspections and pipeline patrolling by AEC personnel would identify construction activities in the vicinity of the pipeline that could result in additional identified sites or a potential class change, as well as a change in signage or conditions that could constitute a 'change in current use'. The identification of any new HCAs would be documented on Form 2.1. Any modification that would be done on the pipeline or processes changes that would occur to the pipeline, such as an increase in operating pressure, modifications to the pipeline diameter, a change in the product transported, or pipeline rerouting, (all of which are very unlikely scenarios), would require a Management of Change (MOC) request, triggering the reassessment of the HCA. Additional detail on the MOC process is provided in Section 12, below.

New information that must be considered in the identification of a new HCA, or impact on a current HCA, includes but is not limited to the following: (255.905 (c))

- Changes in pipeline maximum allowable operating pressure (MAOP),
- Pipeline modifications affecting piping diameter,
- Changes in the commodity transported in the pipeline,
- Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites
- Change in the use of existing buildings (e.g., hotel or house converted to nursing home),
- Installation of new pipeline,
- Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
- Pipeline reroutes,
- Corrections to erroneous pipeline center line data.

Any pipeline segment newly identified as an HCA will be incorporated into the baseline assessment plan with in one year from the date it is identified. (255.905 (c)).

On a frequency not to exceed 3 years, AEC will perform a review of the pipeline corridor against the existing HCA inventory to ensure all HCAs have been identified and are included in the base line assessment plan.

For any newly identified HCA on newly installed segment of pipe, a base line assessment plan will be completed on the affected pipeline segment within ten (10) years from the date the area is identified (255.921 (f) & (9)).

AEC Gas Gathering System – Horseheads, NY
Integrity Management Program
Form 2.1 – Field Report on discovery of Potential New HCA Along Pipeline Corridor

Location of Potential HCA:

1. Pipeline Station No.: ___________________
2. Pipeline Drawing No.: ___________________
3. GPS Location: ___________________
4. Property Plot No.: ___________________
5. Street Address: ___________________

Description of Potential HCA (check all that apply):

1. Institutional (school, hospital, government) ☐
2. Commercial (stores, office building) ☐
3. Industrial (warehouses, factories) ☐
4. Residential ☐
5. New Building, Size – 3 stories or less ☐
   - 4 stories or more ☐
6. Recreational ☐

Drawing:

1. Display location of potential HCA relative to pipeline and provide dimensions.
2. Provide pipeline stationing and north arrow to determine orientation of sketch.

Date of Discovery: _____________________

Routing – Operations Manager: ___________________ Date: _________________
Subject Matter Expert: _________________ Date: _________________

Results of Review by Maintenance Supervisor:

3.0 Risk Assessment Planning

3.1 Assessment Methodology

AEC has developed the following risk assessment program, which consists of a baseline assessment plan and on-going assessment program to provide information to managers to help facilitate decision making and provide an understanding of the nature and locations of risks along the pipeline. AEC has gathered data related to the pipeline, the facility, and the risks to the pipeline, and has developed the following assessment tools appropriate for the pipeline operations at AEC.

3.2 Threat Identification, Data Integration and Risk Assessment

AEC has considered the full range of possible threats to the covered pipeline to assess possible threats to the integrity of the pipeline. Included in the initial threat baseline assessment was consideration of the following categories of potential threats:

- external corrosion,
- internal corrosion,
- stress corrosion cracking;
- manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects,
- welding- or fabrication-related defects,
- equipment failures,
- third party/mechanical damage,
- incorrect operations (including human error),
- weather-related and outside force damage,
- cyclic fatigue or other loading condition,
- all other potential threats.

Potential threats to the covered pipeline segment include internal and external corrosion related activity, defects that were incorporated into the pipeline during fabrication or construction, third party damage, and human error. Because the pipeline location is not historically susceptible to earthquakes, hurricanes, or other extreme weather events outside force damage is not further assessed.

In consideration of the approximately 20,100-feet of individual pipeline being operated by AEC, the risk assessment approach consists of information obtained from SMEs and ASME B31.8S-2004 section 5.5. SMEs are utilized to assess each HCA pipeline segment to identify the relative likelihood of failure for each threat and the related consequence of a failure. By calculation, a relative risk for each potential threat is assigned.

As new information relative to risks and interactive threats to the pipeline as well as other relevant factors are identified, the risk assessment would be revised and the IMP would be updated. Significant changes would be incorporated within 6-months of the identified condition and/or information.

AEC used many of the data sources identified in ASME B31.8S-2004, Table 2 to gather information for assessing risks to the pipeline as well as developing all aspects of the pipeline integrity management program. These sources included P&ID Drawings, original construction records including as-built drawings, material records and certifications, aerial photography, facility drawings and maps, operations and maintenance procedures, inspection records, test reports and records, industry standards, including ASME standards, design/engineering reports, technical evaluations and manufacturer equipment data. All of these records are maintained on site for reference and for inspection.

Using all available pipeline assessment data, including the construction data and historical information compiled for the pipeline, including corrosion control records, surveillance reports, patrolling reports, maintenance history, and the specific HCA, the risks were assessed and are numerically weighted as follows:

Threat Identification Matrix

Threat	Likelihood*	Consequence*	Relative risk**
External corrosion	2	2	4
Third party damage	2	2	4
Manufacturing defect	3	2	6
Internal corrosion	3	3	9
Stress cracking	3	3	9
Construction defects	3	3	9
Human error	3	3	9
Cyclical fatigue	3	3	9

* *1 - High, 2 - Medium, 3 - Low*
** *Product of Likelihood and Consequence*

For this analytical matrix, the range of relative risk can vary from the highest risk level (with a rating of 1) to the lowest risk level (with a rating of 9). Based on the compiled threat identification matrix, the highest relative risk to the AEC HCA pipeline integrity is external corrosion or third party damage with manufacturing defects indicating marginal threats.

The other threats have been determined during the baseline assessment to pose minimal likelihood of occurrence and have been eliminated from risk assessment. Prior to a threat being eliminated from risk assessment, the facility takes into consideration the following:

(a) there is no history of a threat impacting the segment;
(b) the threat is not supported by applicable industry data or experience;
(c) the threat is not implied by related data elements;

(d) the threat is not supported by like/similar analyses; or
(e) the threat is not applicable to the segment operating conditions.

The technical justification for elimination of these threats is discussed below.

Stress Corrosion Cracking
Stress corrosion cracking (SCC) has been eliminated from consideration. In accordance with §255.929, where specific thresholds are exceeded, the HCA segment requires assessment for SCC damage. The following thresholds are established for implementing SCC assessment, all thresholds must be exceeded:

- Age of pipe greater than 10-years
- Operating temperature greater than 100^{o}F
- Operating stress level greater than 60% SMYS
- Distance from compressor station less than 20-miles
- Coating type other than fusion bonded epoxy, FBE

The pipeline operated by AEC does not exceed these thresholds; therefore the threat from SCC has been eliminated. The pipeline operating temperature does not exceed 100^{o}F and has a coating consisting of FBE.

Internal Corrosion
Internal corrosion may occur as the result of fluid or electrolyte entering and/or accumulating in the pipeline. Internal corrosion can result from microorganisms, fluids containing carbon dioxide, oxygen, hydrogen sulfide or other contaminants. Internal corrosion can only occur with the presence of water and/or moisture. Gas components such as sulfur do not cause corrosion unless combined with water.

The gas quality within the AEC pipeline is monitored on a regular basis, is liquid free and considered to be dry natural gas. The potential for internal corrosion activity is monitored by analyzing natural gas samples from the pipeline for sulfur content and monitoring the gas supply 'knock-out pots' coalescing filters for liquids accumulation. The "knock-out" pots are located at the well heads and at the end of the pipeline. The gas velocities are consistently high enough through the line so as to keep any free water entrained in the gas flow and captured in the knock out pots.

AEC maintains records documenting the periodic inspection of the 'knock-out pots' and the absence of water.

External Corrosion
The 12-inch and 4-inch pipeline is coated with fusion bonded epoxy and cathodically protected with distributed magnesium anodes. Direct inspection methods are used to determine the presence or absence of external corrosion.

<u>Human Error</u>
Human error possibilities have been eliminated as there is no equipment between the well head and the metering station. In addition, the AEC Operations Manager maintains overall leadership responsibility for all aspects of facility operation, including implementation of the IMP and the Part 255 requisite pipeline Operating and Maintenance Plan (O&M Plan) inclusive of routine maintenance functions performed by qualified operation and maintenance personnel or outside vendors.

<u>Cyclical Fatigue</u>
Cyclic fatigue has been eliminated as the pipe is not subject to the conditions described in A9.3 of ASME B31 with the exception of a wetland crossing. However, there is no history of the pipeline being exposed and submerged during high water levels. Operational records (pressure charts) support that no cyclical fatigue, incorrect operations or equipment operations have occurred over the pipeline operational life.

<u>Construction Defects</u>
There has been no historical threat identified as related to construction defects. The pipe was installed by a qualified contractor in accordance with applicable construction standards in effect at the time of construction. Construction inspection of the pipeline installation was performed on a daily basis. The pipeline was successfully hydrostatically tested to 150 percent of the MAOP prior to being put into service. The pipeline was tested in February, March and April 2010.

3.3 Pipeline Assessment Approach

Based on the highest derived relative risks to AEC's HCA pipeline segment, the hydrostatic testing method is identified as the most conducive primary means of threat investigation for the 4-inch section of pipeline in an HCA and In-Line-Inspection (ILI) is considered the most effective method for the 12-inch pipeline. Using magnet flux technology and caliper tools, ILI can effectively identify pipeline anomalies caused by internal and external corrosion, pipe defects, and third party damage. There are currently no ILI tools on the market for 4-inch pipelines.

3.4 Pipeline Assessment Schedule

An initial baseline assessment of AEC's HCA pipeline segment was completed in February, March and April 2010 in accordance with 255.921(d) utilizing hydrostatic testing.

Following completion of the baseline integrity assessment program, AEC reassesses the HCA pipeline segment based on the baseline determination of Specified Minimum Yield Strength (SMYS) operating percentile. AEC's planned initial reassessment period is 7 years (2017) in accordance with §255.939, unless performed evaluations indicate earlier reassessment is requisite.

In the unlikely event that AEC installs a new pipeline or identifies a new HCA, the baseline integrity assessment program detailed above would also be used and would be conducted within ten (7) years from the date that the HCA is identified or that the pipeline is installed.

3.5 Data Gathering and Integration

AEC's Gas Gathering System Operations and Maintenance Plan incorporates many integrity management program activities that have been employed since the pipeline was installed in 2010. The information compiled from these activities constitutes a cohesive baseline for understanding the pipeline operating conditions for both the HCA and non-covered segments. The subject activities have been monitored and documented suitably for integration into the inspection, and pipeline integrity management, programs.

The routine tasks that have been completed on scheduled intervals, and/or as delineated in AEC's Operations and Maintenance Plan are identified as follows:

Parameter	*Task*	*Schedule*
Direct Buried Corrosion Control	• Cathodic protection evaluation • Close interval survey (CIS) • Soil resistivity assessment	Annually IMP Baseline Completed 2010
Internal Corrosion Control	Gas quality monitoring	Biannually
Atmospheric Corrosion Control	Coating maintenance	Annually
Patrolling	Observe surface condition on and adjacent to the transmission line ROW	Annually
Line Markers	Marker maintenance	Annually
Mowing ROW	Right of way maintenance	Biannually
Leak Detection Survey	HFID gas leakage survey of pipeline ROW	Annually

AEC maintains data on pipe maintenance activities since installation in 2010. This information is managed within the Maintenance Management Systems, MMS, facilitated by AEC operating personnel. These SME sources include the following:

Process and instrumentation drawings	Operator standards and specifications
Pipeline alignment drawings, both design and GPS confirmed	Industry standards and specifications
Pipeline aerial photography	Test reports and records
Facility maps and drawings	Incident reports
O&M procedures	Compliance records
Manufacturer equipment data	Engineering reports
Survey reports and drawings	Technical evaluations
Safety reports	

The data collected in the HCA may have been collected using different reference point or measurement systems such as pipeline stationing, mileposts or GPS. Once assembled, the information will be inventoried to a common reference system to aide in evaluating threats to the pipeline and potential compounding effects of multiple threats.

4.0 Direct Assessment Plan

AEC employs direct assessment to address identified threats for the HCA pipeline segment. ILI has been chosen as the direct assessment method for that portion of the pipeline accessible to in line tools. A pig launcher located at the point of interconnect with the Ruger 4-inch pipeline and receiver at Hickory Grove make the pipeline accessible for analysis by smart tools. The smart tools will be used for the entire length of the 12-inch portion of AEC's transmission pipeline, including those portions located both inside and outside of the HCA.

Internal anomalies within the HCA on the pipeline laterals will be determined with a magnetic flux leakage tool and caliper tool.

4.1 Pre-Assessment

4.1.1 ILI

4.1.1.1 Pipeline and Component Compatibility with Smart Tools

In preparation for the ILI, questionnaires should be provided by potential vendors(s) and an analysis completed of the pipeline to ensure its compatibility with the tool proposed by the vendor. The following list of items should be checked at a minimum:

- radius bends
- pipeline diameter
- valves, hot taps, tees and other component internals to assure passage of the tool
- any other internal diameter changes
- compatibility of launcher and receiver components with possible tools (barrel lengths, etc.)
- ability to produce required pressures and flows to achieve needed speed of tool
- determine cleanliness of pipeline to meet requirements of tool
- access and work space at launcher and receiver

The above items are to be checked to assure successful launch and free passage of the tool. Upon identification of the ILI vendor, specifications of the equipment proposed for the program should be checked against the attributes of the pipeline to again assure free passage of all tools.

The size of the kicker line should be reviewed to ensure it is adequate to propel the tool.

Removal of any pipeline probes (meters, sensors, etc) and all other devices that project into the pipeline should be reviewed to assure they can be removed prior to launching of any tools.

4.1.1.2 Contracting Considerations

Upon completing discussions of the pipeline attributes with the vendor and selecting a compatible ILI tool a contract should be developed with the vendor specifying the following:

- Scope
- Resource requirements
- Roles and responsibilities
- Schedule
- ILI Specifications ((ability of tool to identify certain size anomalies (size, quantity, depth), identify the type of anomaly (corrosion, manufacturing defect), whether internal or external defect, location along the pipeline against predetermined stations, location on the pipeline (6 o'clock, i.e.), location of pipeline features (girth welds, valves, etc))
- Deliverables at end of run

The scope of work for the ILI tool run should be discussed in detail before finalizing pricing and agreeing to a contract. Responsibilities and roles for handling and launching the ILI tool, identifying locations for the AGMs, tracking the tool, receiving and cleaning the tool, impact of schedule changes on contract pricing and standby and downtime charges should delays in performing or completing the tool run be encountered should be spelled out in the contract.

Responsibility for cost of shipping the tool to the job location, inspecting it upon receipt and assuming responsibility for its care and set up as well as readying the tool for shipping the tool to vendor's next job should be assumed by the tool vendor. The vendor should also take responsibility for all quality checks and certifications for the tool prior to its launch.

Agreement as to what deliverables the vendor will provide, the presentation and format of data collected, the accuracy of the data, the limits of the tool in detecting and identifying the types of anomalies and preliminary and final reports should be addressed in the contract.

The minimum qualifications and experience expected of key vendor personnel, including field and office personnel, should be defined.

4.2 Indirect Examination

4.2.1 Close Interval Survey, CIS

This assessment tool utilizes a data logger and chaining to measure the pipe to soil potentials along the pipeline with respect to a copper sulfate reference electrode. This tool is applicable to pipe sections that are buried under earthen cover.

CIS measures the effectiveness of the cathodic protection system on the pipe under study. The pipeline under consideration is a well coated pipeline with directly attached high potential magnesium anodes.

Analysis of the data obtained and subsequent certification of the cathodic protection system effectiveness is performed in accordance with NACE International Standard Recommended Practice RP0169, latest revision.

The following criteria are used to assess adequate levels of cathodic protection:

- A negative (cathodic) "on" voltage of at least -0.850 volt as measured between the structure and a saturated copper/cooper sulfate reference electrode ($CuCuSO_4$) contacting the electrolyte. For purposes of this analysis, determination of this voltage is made with the protective current applied.

The CIS technique can aid in identifying conditions, such as:

- Interference effects from other cathodic protection systems,
- An electrically shorted casing,
- Contacts with other metallic structures,
- Defective electrical isolating joints.

4.3 In Line Inspection (ILI) of Transmission Pipeline

4.3.1 Pre Field Program Preparations

Certain aspects of the program should be investigated in advance of field activities to assure efficient performance of the field program. Investigation of the following items will reduce the possibility of schedule delays, avoid unknown costs, aid in the establishment of effective communications.

- Coordination with gas or air flow requirements for the ILI run.
- Personnel requirements. The number of individuals needed to launch and receive tools, track tools along pipeline, etc should be determined ahead of the program and arrangements made to have sufficient quantities of personnel available with the appropriate qualification to perform the duties expected.
- Method of communication and to whom. Personnel responsible for tracking tool progress along the pipeline need to be equipped with the appropriate communication devices whether such as cell phones, radios, etc and it be identified to whom and when they communicate updates of the tools progress.
- Disposal of pipeline wastes accumulated during pipe cleaning process and for cleaning of tools. The services of personnel qualified in the cleaning, hauling and disposal of potentially hazardous wastes shall be contracted to clean tools and handle wastes associated with the pipeline cleaning prior to the ILI equipment runs.

- Determine right of way access. Access as required to launcher and receiver locations and points along the pipeline to accommodate tracking the cleaning and ILI tools shall be obtained before commencement of the field program. Access shall consider the needs of vehicles used in the performance of the program.
- Determine any permits needed. Assess special needs of any equipment or vehicles used in the program as they pertain to movement over public roads and highways and obtain permits as required.
- Location and type of above ground markers (AGMs). AGM locations are set in the field at known pipeline stations and GPS coordinates for use in tracking tools as they pass along the pipeline. Where possible, above ground valves and other pipeline features should also be located using pipeline stations and GPS coordinates. The ILI tool will recognize the AGM location and benchmarks and locate pipeline features and identified anomalies in reference to them. This allows for an effective means of locating anomalies in the field for inspection and analysis during the Direct Investigation phase of the program.

4.3.2 ILI Run Set Up

It is important that before the start of field activities that all participants know their roles, responsibilities, expectations and lines of communication. Delays in the efficient performance of the program can result in additional costs and preparations should be taken in advance to avoid such situations.

- Tracking of tools. Personnel capable of recognizing the response of the AGM to the tools passing the location and capable of performing calculations of the tools speed will be stationed at AGMs and other established reference points as necessary. The number of personnel assigned to this effort will be a factor of the speed of the tool and the ability of the personnel to remobilize to subsequent AGM locations.
- Cleaning tools. A program to clean the pipeline, if necessary, should be determined in consultation with the ILI vendor. Several runs with various tools may be required. Poly pig runs may be needed to remove any large items in the pipeline. Brush pigs equipped with scrapers and magnets may be needed to remove rust and other particulate from pipe walls. The cleaning should consider collection of particulate for chemical analysis. The vendor should assume responsibility for determining if the pipeline is sufficiently clean advanced tool runs.
- Gauging tool. A run consisting a tool with various sized plates may be necessary no restrictions exist in certain features of the pipeline. This will aid in ensuring free passage of the ILI tool.
- Caliper tool. A tool to thoroughly inspect internal pipeline geometry may be needed to identify dents and areas of change in pipeline diameter (ovality) that may be sources of restriction to the ILI tool.

- Dummy tool. A tool of similar size, maneuverability and weight may be run as a final check of the pipelines compatibility with the ILI tool and to ensure the tool will traverse the full length of the pipeline.

4.3.3. Perform the ILI run

The ILI run should be performed consistent with the plan established during the preplanning phase and to the ILI vendor protocols. The responsibilities of each person should be reviewed with all participants prior to the arrival of the tool at the launch site. Upon arrival of the tool, any additional concerns of the vendor should also be discussed. A safety meeting should be held to address potential hazards associated with the performance of the program as well as other pertinent safety procedures. The tool is then entered into the launcher.

Parties participating in the ILI run such as remote operation centers should be notified of the start of the program. Communications should be maintained with the center through out the launch and as necessary during the tool run. Confirmation should be made that communications exist with personnel at AGM locations. The tool is then launched and the time recorded.

Personnel stationed at the AGMs, and other established reference points as necessary, should be notified when the tool is launched and be prepared to record the time the tool passes their station. The information should be relayed to the person responsible for tracking the speed of the tool for confirmation that the tool is advancing as planned.

At the end of the run when the tool reaches the receiver and is removed, the vendor and company personnel should inspect the tool for any damage. Photos should be taken to confirm the tool's condition. A determination should be made by the vendor as soon as possible to determine the success of the tool run.

4.3.4 Confirmation of ILI Data Accuracy

Examination of the pipeline in an area exhibiting one or more anomalies will be performed to determine the accuracy of the data generated by the ILI tool. This can be at either an above ground or below ground location. The location of the anomalies in the field, through surface survey control, will be compared to the anomaly location indicated by the ILI tool. ECDA and ICDA will be performed on the anomalies, as applicable, and the readings obtained compared against those generated by the ILI tool. Once the data has been compared and a determination has been made of the accuracy of the ILI data, discussions will be held with the vendor to discuss if discrepancies in data are within the accuracy of the tool and if the ILI program data can be validated.

4.4 Post-Assessment

4.4.1 External Corrosion

Remaining life calculations are required when corrosion defects are found in the pipeline. If no defects are found the remaining life of the pipe can be taken as that of a new pipeline. Where calculations are performed to determine the remaining life, reassessment intervals must be taken as one half the remaining life.

4.4.2 Internal Corrosion

If internal corrosion is detected within the HCA, continued monitoring will be performed. This will be accomplished through the use of both electrical resistance monitoring probes and corrosion coupon evaluation techniques.

Electrical resistance devices utilize calibrated elements made from the same material as the gas pipeline. As the calibrated element experiences corrosion, the cross sectional area resistance of the element changes. Through the calibration and correlation of the instrument, a corrosion rate can be determined. Where no corrosion occurs, the resistance of the probe remains constant.

Corrosion coupons utilize steel components that are introduced into the monitored space. The coupons are pre weighted prior to installation on special holding racks. Following exposures of different time periods, the coupons are cleaned and measured. Weight loss data is then converted into corrosion rate information.

In addition to corrosion rate determination within the casing, water and moisture levels would be determined. The pipe was installed with rubber casing seals on both ends of the casing. These are designed to prevent water migration into the casing.

Data accumulated from these processes will be reviewed annually and a determination made as to whether the time period proposed for reassessment should be adjusted.

4.4.3 In Line Inspection

In the areas of the HCA where passage of the smart tool is possible, data retrieved from this process can be used to determine if any internal corrosion exists in areas where it is most susceptible. If these locations most susceptible to internal corrosion exhibit no defects, the integrity of the balance of the pipeline has been assured.

4.5 Other Assessment Methods

During the direct examination of the pipe, other types of defects may be evident that have not been identified in this program. Where other types of defects are found, such as mechanical damage and stress cracking, alternative methods would be considered for assessing the impact of these defects.

5.0 Remediation

Based on the results of periodic assessments, surveillance work, routine inspections, pipeline patrols, internal or external audits or inspections, additional work may be necessary to ensure the integrity of the pipeline is assured. This repair work is closely managed by AEC to ensure that timely responses to integrity issues are conducted to remedy or eliminate unsafe conditions, establish preventative measures to reduce or eliminate threats to the integrity of the pipeline and to provide an opportunity to reassess inspection intervals or assessment methods if needed. Generally, responses to integrity issues are ranked in the following way:

Immediate: indication shows that defect is at failure point
Scheduled: indication shows defect is significant but not at failure point
Monitored: indication shows defect will not fail before next inspection

The response time frames indicated above shall be used for ILI as well, with the exception that the review for immediate response indications shall be performed upon the receipt of characterization of indications discovered during a successful ILI run. Other indications shall be reviewed within 6 months and a response plan developed. The plan should address both the methods and the timing for the response.

Additional detail on establishing timeframes for remediation is provided below.

5.1 Remediation Work

Following the identification of an integrity issue with the pipeline, a work order is generated within AEC's Maintenance Management System (MMS). This record within the computerized MMS notes the date the issue was identified (which sets forth the actual date of discovery), a scope of the repair work and a tentative schedule and includes a priority ranking of the issue. Resolution of the issue is tracked using the MMS.

Any leak or damage that impairs the serviceability of the pipeline found during the integrity assessment process is permanently repaired as soon as is feasible. If it is not feasible to initially make a permanent repair, a temporary repair may be implemented and followed by more comprehensive repairs that are implemented as practicable.

Should it become necessary AEC can contract the performance of any substantial transmission pipeline repair work to a qualified firm, such as Gas Field Specialists, Inc.:

Gas Field Specialists, Inc.
224 N. Main St. Bldg. 17-2
Horseheads, NY 14845
(607) 796-2523

As their core business this firm maintains all necessary material, parts, tools and personnel required for the prompt corrective repair of any expected transmission pipeline concern.

Permanent field repairs and the testing of permanent field repairs would be implemented in accordance with Parts 255.713 through 255.719.

5.2 Integrity Issues

5.2.1 General

AEC would take prompt action to address anomalous conditions that are discovered during the pipeline integrity assessment. AEC would document the actual date of discovery of any anomalous condition, the condition would be evaluated and any condition that could reduce the pipeline's integrity would be remediated. Documentation would be established demonstrating that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

AEC would schedule remediation of anomalous conditions within specified time restraints as related to the condition. Where AEC is unable to respond to the anomalous condition within the acceptable limits as set forth in §255.933, AEC would temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. Pressure reduction cannot exceed 365 days without technical justification demonstrating that continuation of the pressure reduction will not jeopardize the integrity of the pipeline. Any issue identified as requiring immediate repair would require a temporary pressure reduction or pipeline shut down upon discovery.

All repairs and schedules are documented through the MMS. In the event that a remediation activity cannot be completed within an established timeframe, AEC will document the reason and provide a basis for the reason and will provide detail related to how the revised schedule will not jeopardize public safety. In the event that AEC cannot meet the schedule and cannot provide a temporary reduction in operating pressure or other action, AEC will notify NYS DPS and OPS.

5.2.2 Anomalous Conditions

AEC will implement immediate repair(s) were the following conditions are found on the operating pipeline:

- A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly calculated by acceptable methods.

- A dent that has any indication of metal loss, cracking or a stress riser.

- An indication or anomaly that requires immediate action.

Discovery occurs when an operator has sufficient and adequate information about a threat to determine that the threat presents a potential threat to the integrity of the pipeline. The conditions that present a potential threat include, but are not limited to, the conditions listed in this section as well as the conditions and acceptable threat prevention and repair methods as identified in ASME B31.8S, Table 4.

AEC must obtain sufficient information promptly, but no later than 180 days after conducting an integrity assessment, about the threat to make that determination, unless AEC demonstrates that the 180-day period is impracticable.

AEC provides repair for the following conditions within one year of discovery of either of the following conditions:

- A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

AEC would not schedule the following conditions for remediation, but would record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

- A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

- A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size(NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses would consider weld properties.

6.0 Continual Evaluation and Assessment

6.1 Periodic Evaluations

AEC has developed several procedures in which the pipeline is assessed. These include patrolling, leakage surveys, quality and environmental auditing and site reviews. Each of these evaluation periods provides AEC an opportunity to reassess the integrity management plan and to continuously improve the program using additional data and risk information gleaned from the evaluations. During the review phase of each of these evaluations, improvements can be made to the integrity management program, considering the results of the evaluation, additional data and risk information that is gleaned during the evaluation, remediation decisions that may have been made and consideration is given to additional preventive and mitigative actions. AEC will apply for a waiver from DPS, should it become necessary, to deviate from the required reassessment interval.

6.2 Evaluations during Proposed Changes

Managing and controlling other than 'like-kind' changes made to equipment, facilities, procedures and organizational structure is essential to the safety, health and environment at the facility. AEC is expected to properly manage change in order to minimize risks associated with their implementation. This policy, including the associated checklists and reviews, present guidelines for the proper review, communication, and documentation of critical process and other changes at AEC.

6.3 Minimizing Environmental and Safety Risks

During all assessment and reassessment processes, precautions have been integrated into the process guidelines which detail the assessment work to be done, to ensure that workers are protected, that the public is protected and that the environment is protected. For work conducted by AEC personnel, these safety and environmental precautions are detailed in the standard operating guideline or the maintenance procedure which is used to guide the process. Before work begins, pre-job briefings are held with involved personnel to review the work procedures, as well as safety and environmental precautions. In the event that a contractor is used for an assessment or reassessment, AEC reviews the contractor's work plan for appropriate safety and environmental precautions.

6.4 Confirmatory Direct Assessment

Confirmatory Dire**c**t Assessments **(CDA)** will be performed at the intervals stated in Section 3.4 unless prior assessments and analysis demonstrate a longer period is acceptable or a shorter period required.

Data gathering to be used for CDA should include data collected before, during and since any prior assessments. That data should include information collected from prior corrosion surveys and ongoing threat and risk identification.

7.0 Preventative and Mitigative Measures

AEC has worked with operations, maintenance and engineering personnel to assess the threats to its pipeline and has developed appropriate procedures and measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. The assessment of the threats is provided in Section 4 of this plan and the decision for additional measures considered both the likelihood and the consequences of pipeline failures. The results of all assessments and preventive and mitigative actions, including those detailed throughout this plan, are used in the further development of the IMP and pipeline safety methods.

7.1 Third-Party Damage

AEC has several procedures and programs to decrease the probability of damage to the HCA pipeline segment by third party excavation. These measures are described in detail as part of AEC's pipeline operations and maintenance plan (O&M plan). The procedures and programs described below are employed for any 'excavation' including digging, blasting, boring, tunneling, backfilling, and the removal of above ground structures by either explosive or mechanical means, and/or any other earth moving operations.

- Participating in Dig Safely New York, Incorporated, a one-call underground damage prevention program.

- Ensuring that only qualified site personnel and contractors are involved with pipeline operations, maintenance, repair and assessment or excavations considered in the pipeline/HCA.

- Maintaining information about excavation damage, if it occurs, and the root cause of the damage to develop additional preventative and mitigative measures in HCA.

- Monitoring by qualified personnel of any excavations in the pipeline area

- An annual letter to residents/neighbors along the pipeline right-of-way educating them on the importance (and requirement) of calling dig safely, how to do so, and how to report a pipeline incident or emergency.

- Use qualified personnel for the marking, locating and direct supervision of known excavation activities.

- Patrolling the right-of-way, and noting excavation activities.

- Taking action to prevent and remove encroachments on the right-of-way.

The following maintenance programs are implemented in performing preventive and corrective maintenance on the transmission pipeline. Any portion or segment of pipeline that becomes unsafe to operate will be repaired, replaced, or removed from service.

7.1.1 Patrolling

AEC has implemented a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity and other factors affecting safety and/or operation. Facility personnel additionally observe the right-of-way en route to and from AEC and while performing normal duties.

Following each patrol a report is completed and managed through the AEC Maintenance Management System (MMS). The Maintenance Supervisor (See Table 1.1) initiates any corrective or remedial actions resulting from patrol findings through the MMS. Should a gas leak be detected it is investigated as described in AEC's Pipeline O&M plan, and repaired as indicated. Unauthorized construction activity and/or other encroachments are handled as described in AEC's Pipeline O&M plan.

The pipeline right-of-way is patrolled at least once each calendar year at intervals not exceeding 15 months. Road and railroad crossings are patrolled 2 times each year at intervals not exceeding 7 ½ months. An inspection report is completed during each review and is maintained through the MMS. During the patrol the Maintenance Supervisor inspects conditions for the following:

- Gas leaks
- Washouts or damage to erosion control devices
- Normally covered exposed pipe
- Unauthorized construction activity
- Unusual surface conditions
- Vandalism
- Damaged vents
- Missing or damaged signs or markers
- Increased population
- Indications of construction near the pipeline or in the vicinity of the facility
- Signs or other indications of a change in land use adjacent to the pipeline
- Changes in color of vegetation located over the pipeline

7.1.2 Pressure-Limiting and Pressure–Regulating Stations

In order to prevent accidental over pressurization, AEC's natural gas transmission pipeline was designed and installed to be congruent with the gas wells feeding it. AEC's transmission pipeline has pressure regulating at each well head.

7.2 Corrosion

As detailed above, AEC has a program related to assessing corrosion threats to the pipeline, to ensure that proper assessments are made about whether corrosion exists on a covered pipeline that could impact the integrity of the line. If corrosion is identified, AEC evaluates and remediates the affected section and a schedule is developed to evaluate and remediate, if necessary, similar segments.

8.0 Performance Plan and Measures

AEC monitors the effectiveness of the IMP in protecting the HCA segment as well as the pipeline in general and on a semi-annual basis reports the program results using the DOT Office of Pipeline Safety (OPS) Pipeline and Hazardous Materials Safety Administration (PHMSA) web-based IMP report electronic form.

Four performance measures are monitored and reported on a semi-annual basis. Performance measurements are for the periods January 1 thorough June 30, and July 1 through December 31 for each year. Reports are submitted by February 28th and August 31st each year. The following performance measures are evaluated:

- Number of miles of pipeline inspected verses program requirements.
- Number of immediate repairs completed as a result of the IM inspection program.
- Number of scheduled repairs completed as a result of the IM inspection program.
- Number of leaks, failures and incidents, classified by cause.

Additionally, performance is measured semi-annually in accordance with the threat-specific metrics of ASME B31.8S-2004, Appendix A, which include:

- External corrosion threat
- Internal corrosion threat
- Stress corrosion cracking threat
- Manufacturing threat
- Construction threat
- Equipment threat
- Third-party damage threat
- Incorrect operations threat
- Weather-related and outside force threat

Records of all submittals are maintained on-site. At this time the facility is not choosing to demonstrate exceptional performance in order to not deviate from any requirements of the rule.

Using the MMS AEC additionally monitors additional performance metrics such as gasket failures or leaks that could represent an additional level of risk to the HCA pipeline segment integrity.

AEC's planned initial reassessment period is 7 years (2017) in accordance with §255.939, unless performed evaluations indicate earlier reassessment is requisite. AEC plans to perform direct assessment of external corrosion and internal corrosion threats during the seven-year reassessment.

Where direct assessment evaluations confirm that risks are being controlled, AEC would determine reassessment intervals that do not exceed the maximum intervals (refer to Protocol F) established in §192.939, as follows:

10 years for pipeline segments operating at SMYS levels greater than 50%
15 years for those segments operating between 30 and 50% SMYS
20 years for those segments operating below 30% SMYS

9.0 Record Keeping

AEC maintains records demonstrating compliance with Part 255 IMP requirements for the useful life of the pipeline. IMP records maintained include the following:

- The written Integrity Management Plan
- Operator Qualification Plan
- Gas Pipeline O&M Plan
- Documents supporting revisions to IMP threat identification and risk assessment
- Written baseline assessment plan as incorporated into the written IMP
- Baseline assessment inspection reports
- MOC documents to support any changes used to implement or evaluate the baseline assessment plan or IMP
- Personnel training qualification records
- Schedules that prioritize any conditions found during an assessment that require evaluation and/or remediation including technical justification for the schedule change
- Direct Assessment Plan documentation
- Confirmatory assessment documentation
- Reports and documents needed to carry out the direct and confirmatory direct assessment plan
- Copies of semi-annual monitoring reporting to NYSPSC and OPS, and any other IMP required notification

10.0 Management of Change Process

Managing and controlling changes made to equipment, facilities, procedures and organizational structure are essential to the managing at AEC. Change must be properly managed to minimize risks associated with those changes. The MOC process is a critical component to the facility's quality management system and has been fully integrated into the facility operations.

The MOC process is a formal process that begins when facility personnel contemplate any change in technical, physical, procedural or organizational changes at the facility. The process begins with a complete "MOC Request". The information gathered relates to the reason for the proposed change, equipment needs or modifications necessary, process or procedural changes, document changes, assessment of safety or environmental risks, staffing or contractors needed to conduct the change as well as qualification levels, and financial details. After the completion of the request, the facility conducts review meetings with potentially affected personnel to discuss the proposed change, and then decides whether or not to go forward with the change and sets forth a plan for implementation. Progress on the change is tracked and documented. The AEC Operations Manager manages and oversees the MOC process and tracks the projects through a database.

Included in the MOC process is a review of any project that would impact upon the pipeline or involved that pipeline. No proposed process or operational change can be conducted without this review, and this extends to process or operational changes related to the pipeline. In the event of a modification to the pipeline, the MOC relating to the change would be the documented process through which measures to protect the high consequence area and enhancements to public safety would be identified.

As required in ASME B31.8S-2004 Section 11, the AEC MOC process, includes the following components:

- Reason for change
- Reason for approving changes
- Analysis of implications
- Acquisition of required work permits
- Documentation
- Communication of change to affected parties
- Time limitations
- Identification and qualification of staff

The full MOC process, including documentation of all decisions and considerations, would be conducted prior to implementing any change in the system. Documentation of all MOC process requests is maintained on-site.

11.0 Quality Assurance Process

AEC has fully developed and continues to improve its documented quality management system (QMS). The Operations Manager has overall responsibility for quality.

Guidance provided in ASME B31.8S-2004, Section 12, indicates that pipeline operators that have a quality control program that meets or exceeds the requirements of the ASME standard can incorporate the integrity management program activities into the existing quality program. The requirements are as follows:

- Identify the processes that will be included in the quality program
- Determine the sequence and interaction of these processes
- Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective
- Provide the resources and information necessary to support the operation and monitoring of these processes
- Monitor, measure and analyze these processes
- Implement actions necessary to achieve planned results and continued improvement of these processes.

12.0 Communications Plan

AEC has developed a Public Awareness Program (Attachment 2)in order to keep affected facility personnel, regulators and the public informed about the work the facility does to ensure effective pipeline integrity and the procedures to be taken in an emergency situation.

The AEC Operations Manager is responsible for the overall operation of the facility and implementation of the Public Awareness Program, acting as the administrator for the program. He assures that:

- Target audiences are identified;
- The public awareness message, medium of conveyance, and frequency of delivery is appropriate for each target audience;
- The plan is implemented, and revised as necessary;
- The effectiveness of the program is periodically evaluated; and
- The plan is modified to reflect changes in circumstance.

The sections below detail the components of the Public Awareness Program.

12.1 External Communications

The facility has assessed the need and desire to communicate with interested external parties, including adjacent landowners and public officials. The site has identified abutting property owners and public officials as key interested parties. As part of the Public Awareness Program, there are signs on the pipeline markers which provide details on the pipeline and facility ownership and emergency contact information.

12.1.1 Routine Communications

Since the construction of the gas gathering system, AEC personnel have developed good working relationships with local officials, including the local emergency planning commission, town officials and emergency responders. AEC will continue to maintain these relationships and provide these officials with pertinent information about the facility, the pipeline, and the integrity management program.

On an annual basis, abutting landowners are informed of AEC's efforts to support damage excavation notification and damage prevention initiatives.

Public inquiries about the pipeline integrity management program are welcomed and will be responded to by the AEC Operations Manager or his designee as appropriate.

12.1.2 Communication of an Emergency

Both employees and contractors are trained to initiate a response to any emergency by notifying the AEC Operations Manager. Once notified, the Operations Manager responds in accordance with the procedures to classify the event and implement an appropriate response.

Any environmental emergency associated with the gas pipeline would be managed and responded to by the AEC Maintenance Supervisor. Appropriate communication with local fire, police and other public officials is coordinated by the Maintenance Supervisor, and is supported by AEC's Operations Manager.

12.1.3 Liaison with Public Officials

The Maintenance Supervisor serves as the incident commander for responding to a pipeline or emergency at the AEC Site. Local fire and police are appropriately notified of any emergency which may have potential significant impacts.

12.1.4 Communication with Regulatory Officials

AEC works with regulators to ensure a safe and compliant facility. All concerns raised by OPS and/or the DPS are taken seriously by the facility and site personnel work with regulators to discuss and remedy concerns.

12.2 Internal Communications and Training

It is critical to the safe operation of the pipeline that facility employees understand the components of the IMP and their responsibilities within the program. AEC has developed an Operator Qualification Program, which details the manner in which initial and on-going training are conducted and how the facility ensures that operators are qualified to conduct work related to pipeline operations. The plan also details the manner in which the facility conducts performance measures on an annual basis to ensure the continued competence of employees working with the pipeline.

In addition to the Operator Qualification Program, the Gas Pipeline Operations and Maintenance Plan details training associated with gas pipeline operations and maintenance activities, including training of the emergency response personnel. Both plans are available for inspection upon request.

13.0 Submittal of Program Documents

13.1 General

AEC has developed provisions to submit, upon request, documentation related to the risk analysis and the development and maintenance of the integrity management program. All necessary documentation is maintained on site and is available for inspection by the NYSDPS Office of Gas and Water.

13.2 Document Submittal

AEC submits required IMP notifications and semi-annual reports using the DOT OPS PHMSA web-based IMP reporting electronic form, and by emailing a .pdf report copy to the NYSDPS Office of Gas & Water at (safety@dps.state.ny.us). In the event of a substantial change or significant modification to the IP program or schedule for carrying out the program elements, AEC is required to notify NYSDPS within 30 days of adoption.

13.3 IMP Submittal

Upon request, AEC will submit its integrity management plan to the Department.

FIGURES

FIGURE 1

GENERAL NOTES	REFERENCE DRAWINGS		REFERENCE DRAWINGS		DRAWING STATUS				REVISIONS		
	DWG. NO.	DESCRIPTION	DWG. NO.	DESCRIPTION	NO.	DATE	BY	DESCRIPTION	NO.	DATE	DESCRIPTION
									A	12/08/09	ISSUED FOR CLIENT REVIEW
									0	12/09/09	ISSUED FOR PERMIT

SCALE 1" = 200'		
DRAWN EMS	DATE 12/08/09	
CHK'D EMS	DATE 12/08/09	
APPROVED EMS	DATE 12/09/09	
EMS JOB NO. 4578		
AFE/P.O.NO.		
CLIENT FILE NO.		
EMS FILE NO.		

ENERGY MANAGEMENT & SERVICES CO.
109 FIELDVIEW DRIVE
VERSAILLES, KENTUCKY 40383
TEL:(859) 873-0076 • FAX:(859) 873-5872
9990 RICHMOND AVE. SUITE 202 SOUTH
HOUSTON, TEXAS 77042
TEL:(713) 456-7880 • FAX:(713) 456-7881

ANSCHUTZ EXPLORATION CORPORATION

ACCESS ROADS
LOCATION MAP
RUGER #1/A-5 TIE-IN
HORSEHEADS GAS GATHERING SYSTEM
CHEMUNG COUNTY, NEW YORK

NO. 45781103 REV. 0

GENERAL NOTES	REFERENCE DRAWINGS		REFERENCE DRAWINGS		DRAWING STATUS				REVISIONS		
	DWG. NO.	DESCRIPTION	DWG. NO.	DESCRIPTION	NO.	DATE	BY	DESCRIPTION	NO.	DATE	DESCRIPTION
									A	12/08/09	ISSUED FOR CLIENT REVIEW
									0	12/09/09	ISSUED FOR PERMIT

SCALE	1" = 200'		
DRAWN	EMS	DATE	12/08/09
CHK'D	EMS	DATE	12/08/09
APPROVED	EMS	DATE	12/09/09
EMS JOB NO.	4578		
AFE/P.O.NO.			
CLIENT FILE NO.			
EMS FILE NO.			

EMS
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ANSCHUTZ EXPLORATION CORPORATION

ACCESS ROADS
LOCATION MAP
CAH #1/A-5 TIE-IN
HORSEHEADS GAS GATHERING SYSTEM
CHEMUNG COUNTY, NEW YORK

NO. 45781102 REV. 0

GENERAL NOTES

PIPELINE LOCATIONS ARE APPROXIMATE

REFERENCE DRAWINGS

DWG. NO.	DESCRIPTION

REFERENCE DRAWINGS

DWG. NO.	DESCRIPTION

DRAWING STATUS

NO.	DATE	BY	DESCRIPTION

REVISIONS

NO.	DATE	DESCRIPTION
A	12/08/09	ISSUED FOR CLIENT REVIEW
0	12/09/09	ISSUED FOR PERMIT

SCALE	1" = 50'		
DRAWN	EMS	DATE	12/08/09
CHK'D	EMS	DATE	12/08/09
APPROVED	EMS	DATE	12/09/09
EMS JOB NO.	4578		
AFE/P.O.NO.			
CLIENT FILE NO.			
EMS FILE NO.			

EMS
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ANSCHUTZ

ACCESS ROADS
SITE LOCATION
ANSCHUTZ/MILLENNIUM CUSTODY TRANSFER STATION
HORSEHEADS GAS GATHERING SYSTEM
CHEMUNG COUNTY, NEW YORK

NO.	REV.
45781101	0

FIGURE 2

FIGURE 3

SYMBOLS LEGEND

ANODE; TEST STATION; RECTIFIER; REGULATOR STATION; MAIN LINE VALVE; CHECK VALVE; VALVE; METER; GAS WELL; EQUATION; CASING; PIG LAUNCHER; WATER METER; WATER VALVE; WATER WELL; FIRE HYDRANT; MANHOLE; TELEPHONE PEDESTAL; STORM INLET; UTILITY POLE; UTILITY POLE WITH LIGHT; TRANSMISSION TOWER; GUY ANCHOR; IRON PIN; TRAVERSE POINT; SURVEY MONUMENT; BENCHMARK; CEMETERY; MILE POINT; WARNING SIGN; TREE; OVERHEAD CABLE (C); OVERHEAD ELECTRIC (E); OVERHEAD TELEPHONE (T); OVERHEAD ELECTRIC AND CABLE (EC); OVERHEAD ELECTRIC AND TELEPHONE (ET); OVERHEAD CABLE AND TELEPHONE (CT); OVERHEAD ELECTRIC, CABLE AND TELEPHONE (EC&T); STORM SEWER (S); UNDERGROUND CABLE (UC); UNDERGROUND ELECTRIC (UE); UNDERGROUND TELEPHONE (UT); UNDERGROUND ELECTRIC AND CABLE (UEC); UNDERGROUND ELECTRIC AND TELEPHONE (UET); UNDERGROUND CABLE AND TELEPHONE (UCT); UNDERGROUND ELECTRIC, CABLE AND TELEPHONE (UEC&T); SANITARY SEWER (SS); WATER LINE (W); GAS LINE (G); PROPERTY LINE (PL); FENCE LINE (X); RAILROAD; STREAM/CREEK; WOODS; WETLANDS

GENERAL NOTES

MATERIAL SUMMARY

MK. NO.	QTY.	DESCRIPTION

MATERIAL SUMMARY

MK. NO.	QTY.	DESCRIPTION

REVISIONS

NO.	DATE	BY	DESCRIPTION

SCALE	1" = 200'
DRAWN REP	DATE 10/08/10
CHK'D	DATE
APPROVED	DATE
EMS JOB NO.	4578
AFE/P.O.NO.	
CLIENT FILE NO.	
EMS FILE NO.	4578-Greystar100810a.mxd

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ANSCHUTZ EXPLORATION CORPORATION

TITLE
HORSEHEADS GAS GATHERING SYSTEM
HCA DOCUMENTATION MAP
CHEMUNG COUNTY, NEW YORK

NO. 45789001 REV. 2

SYMBOLS LEGEND	GENERAL NOTES

MATERIAL SUMMARY

MK. NO.	QTY.	DESCRIPTION

MATERIAL SUMMARY

MK. NO.	QTY.	DESCRIPTION

REVISIONS

NO.	DATE	BY	DESCRIPTION

SCALE 1" = 200'	
DRAWN REP	DATE 10/08/10
CHK'D	DATE
APPROVED	DATE
EMS JOB NO. 4578	
AFE/P.O.NO.	
CLIENT FILE NO.	
EMS FILE NO. 4578-Greystar100810a.mxd	

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ATTACHMENTS

1.0 Operation and Maintenance Plan

2.0 Public Awareness Program

3.0 Operator Qualification Program

4.0 Annual Corrosion Report