



January 7, 2013

Mr. David Barrett  
Director, Central Region  
Pipeline Hazardous Materials Safety Administration  
901 Locust Street, Suite 462  
Kansas City, MO 64106-2641

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**Reference:** CPF 3-2012-1011M  
**Dated:** December 8-10, 2010

Dear Mr. Barrett:

We have received your letter dated November 27, 2012 following an inspection on December 8-10, 2010. The inspection covered the PostRock KPC Pipeline, LLC, now renamed to KPC Pipeline, LLC (KPC). During the Integrity Management Program Annual Review in October 2012, the KPC Integrity Management Team decided to change their current to Integrity Management Plan from RCP's plan to a plan customized to KPC by The Compliance Group, Inc. The change to the new Integrity Management Program manual has resolved the stated inadequacies found by the PHMSA inspector.

1. **An identification of all high consequence areas, in accordance with §192.905.**

**§192.905 How does an operator identify a high consequence area?**

**Item 1A: (b)(1) Identified Sites. An operator must identify an identified site, for purposes of this subpart, from information the operators obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.**

PostRock's procedures for identifying new covered segments were inadequate because they did not ensure that information obtained from routine operations and maintenance activities, such as, patrolling, continuing surveillance, and similar functions, was incorporated into the integrity management program and evaluated for new high consequence are determinations.

**KPC Response:** KPC performs routine operations and maintenance activities as part of the KPC O&M Manual procedures. KPC will utilize the data gathered from these activities in the KPC Integrity Management Program.

- i. The following statement was pulled from page 1-2, §1.1 of the KPC 2012 Integrity Management Plan (Attachment A1): “KPC will perform an update to the HCA analysis when new data becomes available from either the class location house count survey or data gathering by field personnel for validating applicable PIR buffer zones used in determining any new identified sites.”
- ii. The following statement was pulled from page 1-5, §1.6 of the KPC 2012 Integrity Management Plan (Attachment A2): “Routine Operations and Maintenance activities should also be used to identify any pipelines that need to be included in the Integrity Management Program.”

2. **An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.**

**§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

**Item 2A: (a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2...**

PostRock’s procedures were inadequate because they do not contain an analysis or evaluation of the potential detrimental impacts on pipeline integrity that might occur due to the possibility of interaction between existing identified threats.

**KPC Response:** Section 3.1 of the KPC 2012 Integrity Management Plan includes a process for evaluating interactive threats. The process starts on page 3-2 and continues with Form 3.1 on page 3-3. This section is included in this response as Attachment B.

**Item 2B: (b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.**

PostRock's procedures were inadequate because they did not clearly define how existing data on the entire pipeline, including non-covered segments, was gathered, integrated, and applied to the risk analysis on similar covered segments. For example, procedures did not specify whether a leak on a non-covered segment of a pipeline contributes to the leak history of a covered segment on the same pipeline that experienced a similar operational, maintenance, and corrosion control history.

**KPC Response:** Section 3 of the 2012 KPC Integrity Management Plan goes into greater detail in the risk analysis data gathering process (Section 3 is included as Attachment C1). Below are a few examples from Section 3 and language pulled from Section 8 regarding corrosion data gathering.

- i. The following statement was pulled from page 3-5 of §3.2: "KPC will collect, manage, and integrate existing data and information on the entire pipeline that could be relevant to covered segments and non-covered segments where applicable."
- ii. The following statement was pulled from page 3-4 of §3.1: "Leak and incident history, repair history, and cathodic protection history (on covered segments and non-covered segments that share a similar operational, maintenance and corrosion history)"
- iii. The following statement was pulled from page 8-7 of §8.6 (included in Attachment C2): "Leak and incident history, repair history, and cathodic protection history (on covered segments and non-covered segments that share a similar operational, maintenance and corrosion history)."

**Item 2C: (e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat. (5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.**

PostRock's procedures were inadequate because they did not clearly require that both covered and non-covered pipeline segments with similar coating and environmental characteristics be evaluated and remediated when corrosion that could adversely affect the integrity of a covered pipeline segment is identified. The procedures currently link this evaluation to the Threat Severity Index, not to the identification of actual corrosion that could adversely affect pipeline integrity.

**KPC Response:** The Risk Assessment process no longer links the process to a Threat Severity Index. The following statement was pulled from page 3-6 of §3.3 in the KPC 2012 Integrity Management Plan (Attachment C3): "This process [Risk Assessment process] involves gathering data on the design, construction, operation, maintenance, testing, inspection and other information about the pipeline system (including non-covered segments with similar coating and environmental characteristics)."

3. Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence areas.

**§192.335 What additional preventive and mitigative measures must an operator take?**

**Item 3A: (a) General requirements.** An operator must take additional measure beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An Operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to...

PostRock's procedures were inadequate because they only required that additional preventive and mitigative measures be considered whenever the Threat Severity Index of a given threat exceeds 67% criterion. Preventive and mitigative measures may be valuable and appropriate to address identified threats and should be considered even though this threshold has not been met. PostRock's procedures were also inadequate because they did not consider a range of potential measures, but only those specifically listed in the regulations.

**KPC Response:**

- i. The KPC 2012 Integrity Management Plan does not limit the preventive and mitigative measures to only those lines with a specific threat level. The plan also considers a broader range of potential measures, not solely those listed in the regulations. Specifically, the following statement is pulled from §8.1 "KPC will take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a High Consequence Area." (Attachment D1)

**Item 3B: (c) Automatic shut-off valves (ASV) or Remote control valves (RCV).** If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

PostRock's procedures were inadequate because they did not delineate an evaluation process based on risk analysis even though the specified factors are to be considered. An analysis of remotely-controlled and automatic shutoff valves to reduce the consequences of a release on the KPC system was reportedly performed by Enbridge when they operated the system; however, that analysis was not available for review during the inspection.

**KPC Response:**

- i. The KPC 2012 Integrity Management Plan (§8.7) requires a risk reduction analysis to determine if either an ASV or RCV would be an appropriate means of providing additional protection in a high consequence area. (Attachment D2)

**4. A management of change process as outlined in ASME/ANSI B31.8S, section 11.**

**Item 4A:**

PostRock's procedures were inadequate because they did not ensure that physical changes to the pipeline system are evaluated for potential impact on the integrity management program **prior to implementation.**

**KPC Response:** KPC will evaluate changes planned to the KPC pipeline system prior to the changes being implemented. The following statement was pulled from page 11-1 of §11.2 in the KPC 2012 Integrity Management Plan (Attachment E): "Formal management of change (MOC) procedures has been developed in order to identify and consider the impact of changes to the KPC pipeline systems and their integrity prior to implementing the change."

**5. A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.**

**Item 5A:**

PostRock's procedures were inadequate because they did not adequately delineate the roles and responsibilities for key personnel in performing integrity management related activities. For example, the position descriptions for the Operations Manager and System Supervisor did not refer to integrity management even though these positions play a key role in developing and implementing the program.

**KPC Response:**

- i. The KPC 2012 Integrity Management Plan lists specific integrity responsibilities for key personnel in the Introduction, page Intro-4, §1.1. (Attachment F)

**6. A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, includes procedures for addressing safety concerns raised by –**

**(1) OPS; and**

**(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.**

**Item 6A:**

PostRock's procedures were inadequate because they only included provisions for responding to formal expressions of concern, such as Notice letters. The procedures did not provide guidance on how PostRock personnel should respond to safety concerns that are expressed through more informal means of communications, such as, via telephone call or email.

**KPC Response:**

- i. The KPC 2012 Integrity Management Plan provides guidance for responding to any concerns, not just concerns provided through formal Notice letters. The following statement is pulled from page 13-2 of §13.2 (Attachment G): “Any safety concerns noted by the PHMSA or state Pipeline Safety Authorities will be promptly addressed by the IMT to assure continued safe operations and compliance of the KPC pipeline system.”

It is toward KPC's continuing commitment to operate in a manner that not only complies with Federal regulations, but ensures the safety of all operating personnel and affected population that we appreciate this opportunity to address the items brought forth in your letter. Should specific items provided to evidence our compliance be found not sufficient, please advise so that we may remedy the issues as soon as possible.

If you should have any questions or require further information please contact me at (913)764-6015.

Sincerely,



Joe Fowler  
Operations Manager

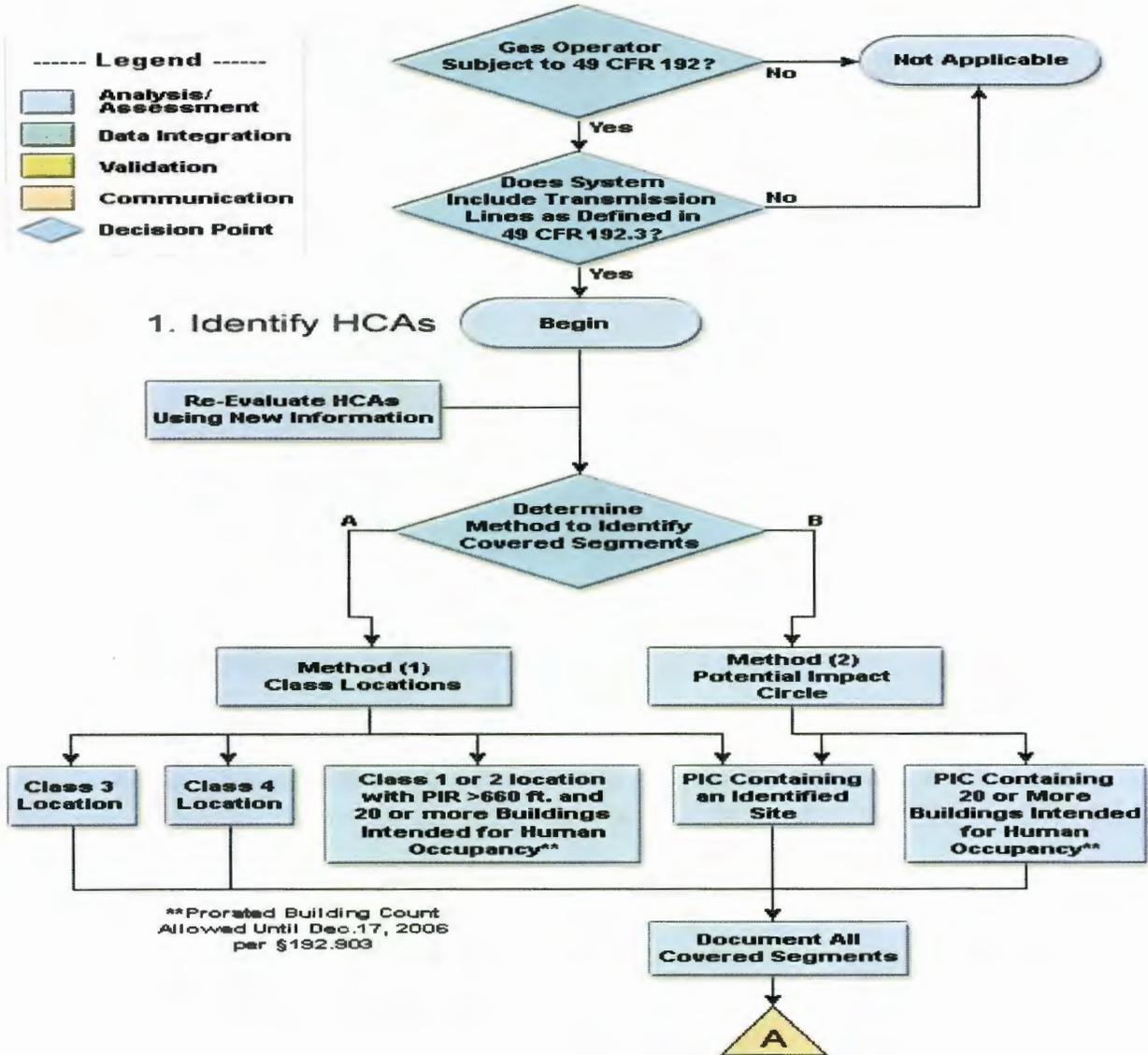
enclosures

**ATTACHMENT A1**

# SECTION 1 Identification of HCA's

## 1.1 HCA Identification Process

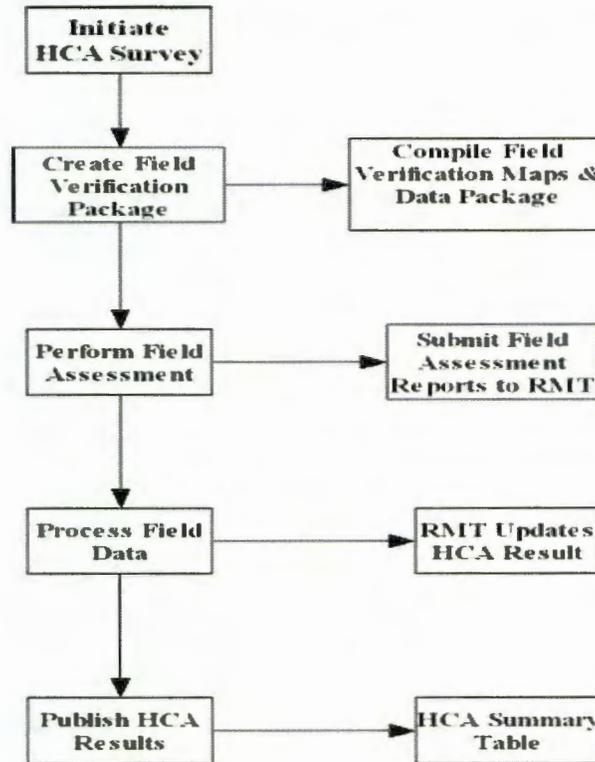
### Determine Rule Applicability



A high level definition of the process has been provided below. High Consequence Areas are identified through 5 primary phases. This process is to be completed annually.

# SECTION 1

## Identification of HCA's



KPC will perform an update to the HCA analysis when new data becomes available from either the class location house count survey or data gathering by field personnel for validating applicable PIR buffer zones used in determining any new identified sites.

Each HCA or identified site that could be affected will be uniquely identified and correlated to the segment(s) that could affect them.

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The various types of sites expected are listed below. Those that shall be treated as Identified Sites are noted as such in the table.

Site Type	Examples	Identified Site?
<b>Occupied Building</b>	Building occupied by 20 or more persons on at least five days a week for ten weeks in any 12 month period. The days and weeks need not be consecutive.  Examples include, but are not limited to: Religious facilities, office buildings, community centers, general stores, 4-H facilities, roller skating rinks, etc.	Yes
<b>Not Intended for Human Occupancy</b>	Structures that appear in aerial imagery, but are confirmed to not be intended for human occupancy. Examples include, but are not limited to: Gas station pump covers, water tanks, etc.	No
<b>Outside Public Assembly Area</b>	Where occupied by 20 or more persons on at least 50 days in any 12 month period. Examples include, but are not limited to: Parks, Playgrounds, camping grounds, outdoor theaters, beaches, recreation facilities, stadiums, areas by buildings of congregation such as churches, etc.	Yes
<b>Multi-Family Dwelling</b>	Where > 20 Dwellings are within PIR circle	Yes
<b>School</b>	Pre-K—12, college, university, trade school, business school, training facility, public, private, charter, or other place of learning	Yes
<b>Hospital</b>	Hospital, nursing home, assisted living, retirement homes	Yes
<b>Prison</b>	Prisoners contained to cells.	Yes
<b>Day Care</b>	Child care and Elder Care facilities	Yes
<b>Impaired Mobility Dwelling</b>	A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include, but are not limited to: Schools, day-cares facilities, retirement facilities, assisted living facilities, etc. Where occupied by 20 or more persons on at least 50 days in any 12 month period.	Yes
<b>Recreational Facility</b>	Park, arena, golf course club house, sporting complex, and any other place where people congregate for recreational activities. Where occupied by 20 or more persons on at least 50 days in any 12 month period.	Yes
<b>Public Official</b>	Office, satellite, building or other location of local public official.	Yes
<b>Emergency Responder</b>	Office, satellite, building or other location of emergency responder.	Yes
<b>Field Verified Outside of PIR</b>	Sites that are shown on the map to be within the <u>Extended Potential Impact Radius</u> , but have been verified by field survey to be outside of the Potential Impact Radius.	No

**ATTACHMENT A2**

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- Impact Circle contains 20 or more buildings intended for human occupancy; or  
 (iv) The area within the Potential Impact Circle contains an identified site.

## 1.5 Identification Using Potential Impact Radius (PIR) (Method 2)

$$\text{PIR} = \text{Gas Factor} \times \sqrt{(\text{Diameter} \times \text{MAOP}^2)}$$

Where: PIR = Potential Impact Radius (feet)  
 Gas Factor = 0.69 (factor for natural gas)  
 Diameter = Nominal diameter of the pipeline (inches)  
 MAOP = Maximum allowable operating pressure of pipeline segment (psi)

Using Method 2 as described in the HCA definition, the HCA sites listed in **APPENDIX A** were identified. In addition, an extended PIR shall be utilized to account for Image Accuracy Error. Extended PIR = PIR + Image Accuracy Error.

## 1.6 Identification and Evaluation of Newly Identified HCA's, Program Requirements

Procedure for Determining Newly Identified High Consequence Areas:

If any of the events below occur during the year following the RMT HCA annual review, KPC will document the event(s). That data shall be retained to serve as supporting documentation for the following year's HCA identification review.

- New site identified / Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
- Change in pipeline MAOP
- Line size modification
- Change in commodity transported or BTU heat value
- 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 use of existing site
- Installation of new pipeline
- Pipeline reroute
- Correction to erroneous pipeline centerline data

Routine Operations and Maintenance activities should also be used to identify any pipelines that need to be included in the Integrity Management Program. Any actions by KPC that could affect a change to the HCA list are to be communicated in writing to the RMT, prior to the effective date of the change. The RMT will then issue in a timely manner a revised list of HCAs subject to 49 CFR Part 192 so that changes required by

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this program can be made at the next scheduled annual update, either in-house or by contract services.

Historical documentation and verification of HCA mapping is the responsibility of the RMT. For pipeline locations that are taken from alignment sheets, aerial or pipeline maps, the RMT will address the reliability of the information and use other data sources if necessary to completely and accurately identify pipeline locations.

A GPS survey has been conducted to assure the location of pipeline HCAs are accurately identified. Pipeline operation and maintenance records will be used for visually integrating pipeline data affecting HCAs on a hard copy map or other equivalent record (leaks, third party damage, new construction activity, corrosion P/S survey data).

KPC will integrate any new or revised HCA mapping data for producing an updated map. See **FIGURE 1.1** 'HCA Segment Identification Process'. Redlined changes from field verification approved by the Risk Management Team may on a case-by-case basis require electronic mapping revisions.



**SECTION 1  
Identification of HCA's**

**Checklist – HCA Identification Method 2**

KPC will utilize Method 2 from the definition of High Consequence Areas in §192.903 to identify HCA's. See process flow chart below **FIGURE 1.1**.

No.	Task Description
1.0	<b>Initiate HCA Survey</b>
	<b>Responsible: Program Coordinator and Area Management</b>
	<input type="checkbox"/> Create listing of Systems for HCA assessment utilizing prior year results and newly added systems. <input type="checkbox"/> Schedule kick-off meeting with Risk Management Team to review list of systems to be assessed. Discuss Baseline Assessment Plan and define schedule/deliverable expectations.
2.0	<b>Create Field Verification Package</b>
	<b>Responsible: RMT</b>
	<input type="checkbox"/> Review HCA Summary Segment Lists to locate Missing or Unsubstantiated Data. <input type="checkbox"/> Create spreadsheet containing missing fields for Field Technicians to complete. The missing data may be mined from local field documents and SMEs. <input type="checkbox"/> Create Field Packages to Include as necessary, Centerline Maps, Structures, HCAs, PIR Buffers, and Aerial Imagery to assist field verification.
3.0	<b>Field Assessment</b>
	<b>Responsible: Program Coordinator and Area Management</b>
3.1	<b>Consult with Local Public Officials</b>
	<input type="checkbox"/> Meet with Field Office Personnel to: <ul style="list-style-type: none"> <li>• Discuss the need for Field Operations Personnel to maintain a current list of Local Public Officials.</li> <li>• Request that Field Operation Personnel create records of visits at Local Public Offices near the pipeline right of way. Reports must be created using Form 1.1.</li> </ul>
3.2	<b>Verify Current HCAs:</b> <input type="checkbox"/> Revalidating previously Identified Sites within the PIR buffer. This reevaluation shall only include the verification that the population remains sufficient to qualify the area as an HCA.
3.3	<b>Identify Potential New HCAs:</b> <input type="checkbox"/> Locate potential HCAs by identifying all potential Identified Sites and twenty or more buildings intended for human occupancy clusters within the PIR buffer. The potential HCA will extend axially from the outermost edge of the first potential impact circle touching an Identified Site or twenty or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle containing an Identified Site or twenty or more buildings intended for human occupancy. This file is only a preliminary identification of HCA boundaries. The final HCA is not defined until step 5.1 below.
3.4	<b>Field Verification Final Reports</b> <input type="checkbox"/> Compile and quality check all HCA Reports, Form 1.1, gathered above. <input type="checkbox"/> Plan to discuss Field Verification Results per system with RMT.
4.0	<b>Process Field Data</b>
	<b>Responsible: Program Coordinator and Area Management along with (Contract Consultant)</b>
4.1	<b>Process Field Data:</b> <input type="checkbox"/> Update maps and tables with Field Verified HCA Data.



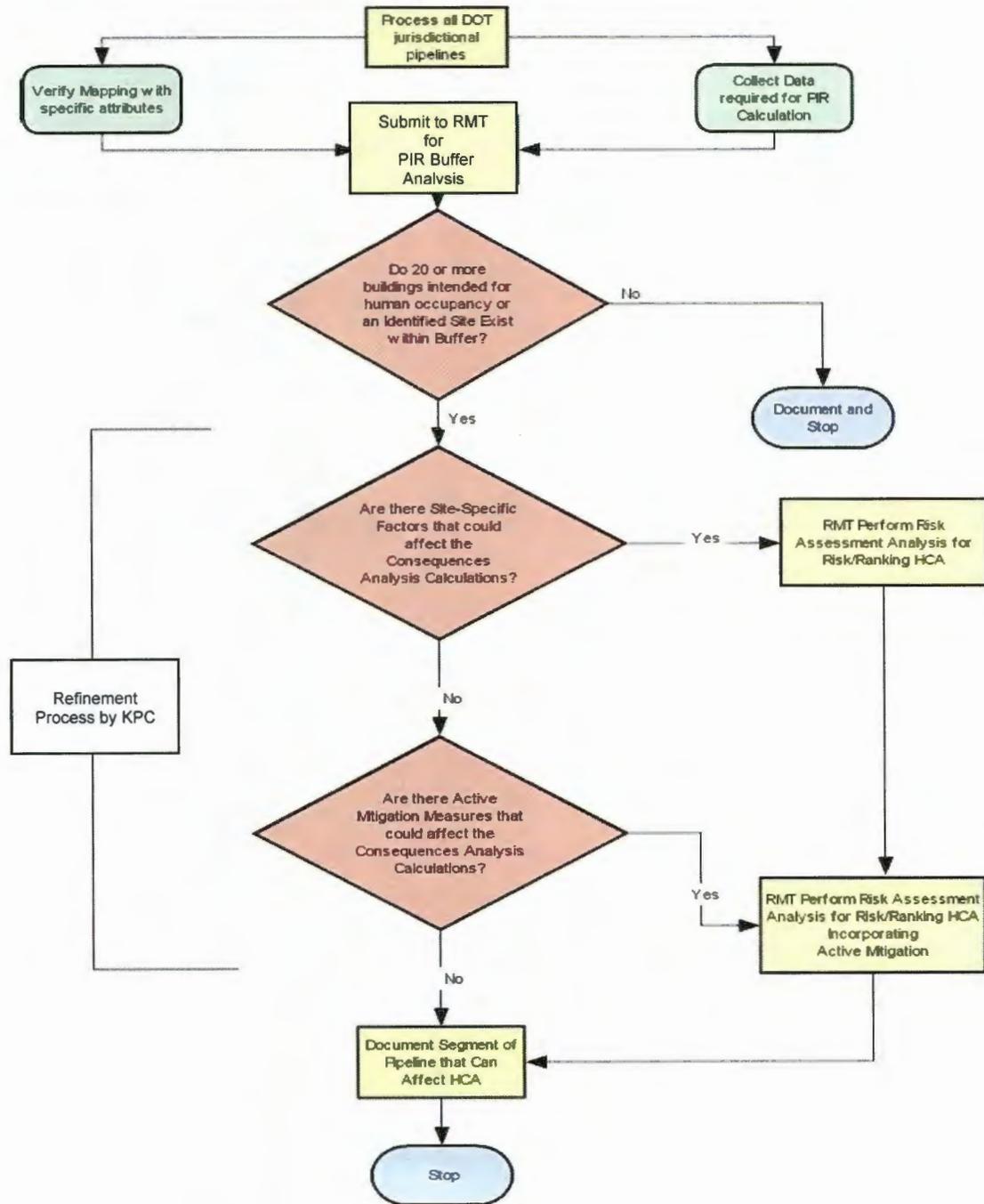
**SECTION 1  
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5.0	<b>Publish HCA Assessment Results</b>
	<b>Responsible: Integrity Management System Coordinator</b>
5.1	<b>Publish HCA Assessment Results:</b> <ul style="list-style-type: none"><li><input type="checkbox"/> Review quality of records for all newly identified and updated HCAs.</li><li><input type="checkbox"/> Compile final updates and clarifications into final HCA Results Table</li><li><input type="checkbox"/> Integrate final HCA Results Table to Threat/ Risk and Baseline Assessment Plans.</li></ul>

# SECTION 1 Identification of HCA's

Figure 1.1

## HCA Segment Identification Process Using Method 2



**ATTACHMENT B**

	<b>Integrity Management Program</b>	
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### 3.1 Threat Identification

**SECTION 3** defines the KPC Integrity Management Program Threat Identification, Data Integration, and Risk Assessment process. Section 192.917(a) requires all potential threats to each covered pipeline segment be identified and evaluated. The threat identification process includes consideration of the 21 threats [ASME B31.8S (latest PHMSA referenced edition), Section 2.2] associated with the first nine categories for this risk analysis:

ASME B31.8S (latest PHMSA referenced edition), Section.2.2 Integrity Threat Classification.

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed. One of the causes reported by operators is "unknown"; that is, no root cause or causes were identified. The remaining 21 threats have been grouped into nine (9) categories of related failure types according to their nature and growth characteristics and further delineated by three (3) time-related defect types. The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

#### (1) Time-Dependent

- External Corrosion (EC)
- Internal Corrosion (IC)
- Stress Corrosion Cracking (SCC)
- Cyclic fatigue or other loading condition (CF)

#### (2) Stable

- Manufacturing Related Defects (MD)
  - 1 Defective pipe seam
  - 2 Defective pipe
- Construction/Welding/Fabrication Related (CT)
  - 1 Defective pipe girth weld
  - 2 Fabrication weld
  - 3 Wrinkle bend or buckle
  - 4 Stripped threads/broken pipe/coupling failure
- Equipment (EF)
  - 1 Gasket O-ring failure
  - 2 Control/Relief equipment malfunction
  - 3 Seal/pump packing failure
  - 4 Miscellaneous

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**(3) Time-Independent**

- Third Party/Mechanical Damage (3PD)
  - 1 Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
  - 2 Previously damaged pipe (delayed failure mode)
  - 3 Vandalism
- Incorrect Operations (IO)
  - 1 Incorrect operational procedure
- Weather Related and Outside Force (WE)
  - 1 Cold weather
  - 2 Lightning
  - 3 Heavy rains or floods
  - 4 Earth Movements

**(4) All Other Potential Threats**

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has a third party damage dent. KPC utilized the following example matrix to assist the consideration of interactive threat analysis of each HCA:

**Form 3.1 – Interactive Threats**

	EC	IC	SCC	MD	CT	EF	3PD	IO	WE	CF
EC				X			X		X	X
IC	X*			X			X			
SCC										
MD							X			
CT				X			X			
EF										
3PD	X*	X		X	X				X	X
IO										
WE							X			X
CF							X		X	

\*Interactive threats are listed by reading the Column entries. For example, for the Column EC (External Corrosion), two interactive threats are shown – IC (Internal Corrosion) and 3PD (Third Party Damage).

Historically, metallurgical fatigue has not been a significant issue for gas pipelines. However, if operational modes change and pipeline segments operate with significant pressure fluctuations, KPC will consider fatigue as an additional factor.

KPC shall consider each threat individually, interacting, or in the nine categories when following the process selected for each pipeline system or segment.

The model is periodically updated whenever changes occur affecting the HCA attributes, identified site, or additional HCAs are identified. Gathering the input data, analyzing the nature and potential for interacting threats to the pipeline, ensuring consistent relative weighting factors are assigned, is the responsibility of the Risk Management Team. A slightly modified Muhlbauer risk ranking model was utilized, with plans for continuous improvement and refinement.



## SECTION 3

# Identify Threats, Data Integration, and Risk Assessment

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The output of the risk assessment model identifies the nature and location of the most significant anticipated risks, thereby allowing identified HCA segments to be risk ranked, prioritized, and scheduled for assessment accordingly. The model output may also indicate areas needing to employ additional preventive and mitigative measures as well as improvements to the Model itself. As additional pertinent data become available, the risk assessment will be updated to determine the effects, if any, on HCA segment rankings, subsequent assessments and other relevant measures to increase overall pipeline integrity.

After the risk model is run, the Risk Management Team will review the results for reasonableness. The review will primarily be a check of the reasonableness of the relative risk ranking of the segments in the IMP. Data will be re-verified if necessary.

The integrity management rule also requires that the operator must consider all information relevant to determining risk associated with pipeline operation that could affect HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. A list of some of the more important information that KPC will consider in an integrated manner is provided below:

- Results of previous integrity assessments, defect type and size that the assessment method can detect, and defect growth rate;
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness);
- Leak and incident history, repair history, and cathodic protection history (on covered segments and non-covered segments that share a similar operational, maintenance and corrosion history);
- Operating stress level;
- Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities, and development or planned development along the pipeline;
- Population density;
- Proximity of the population to the pipeline taking into account man-made or natural barriers that might provide protection;
- Proximity of the potential event to population with limited mobility (hospitals, schools, child-care facilities, recreational facilities, prisons) particularly in unprotected facilities;
- Property damage;
- Environmental damage;
- Effects of un-ignited gas releases;
- Public convenience and necessity;
- Potential for secondary failures;
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
- Geo-technical hazards;
- Physical support of the segment such as by a cable suspension bridge;

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- Corrosion control information (e.g., test station readings, close interval survey results);
- Operating parameters (e.g., maximum operating pressure, pressure cycle history);
- Information critical to determining the potential for, and prevention of, damage due to excavation;
- Data gathered in conjunction with inspections, tests, surveillance, and patrols, including corrosion control monitoring and cathodic protection (CP) surveys;
- Information about how a failure would affect a HCA; and
- Data gathered through near miss and incident investigations.

### **3.2 Data Gathering and Integration**

The Integrity Management Plan including the threat identification is an iterative process that involves data gathering and organizing and completion of the risk assessment of each threat and for each of the pipeline segments. KPC will collect, manage, and integrate existing data and information on the entire pipeline that could be relevant to covered segments and non-covered segments where applicable. Integrating newly arising information, applicable threats, and risks (including completed prevention and mitigation actions) that may require changes to the segment prioritization or assessment method is the responsibility of the Risk Management Team and will be performed annually unless the newly identified threats require immediate modification of the BAP. Typical data sources for pipeline integrity program include:

- Process and instrumentation drawings (P&ID)
- Pipeline alignment drawings
- Original construction inspector notes/records
- Pipeline aerial photography
- Facility drawings/maps
- As-built drawings
- Material certifications
- Survey reports/drawings
- Safety related condition reports
- Operator standards/specifications
- Industry standards/specifications
- O&M procedures
- Emergency response plans
- Inspection records
- Test reports/records
- Incident reports
- Compliance records
- Design/engineering reports
- Technical evaluations
- Manufacturer equipment data

**ATTACHMENT C1**

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### 3.1 Threat Identification

**SECTION 3** defines the KPC Integrity Management Program Threat Identification, Data Integration, and Risk Assessment process. Section 192.917(a) requires all potential threats to each covered pipeline segment be identified and evaluated. The threat identification process includes consideration of the 21 threats [ASME B31.8S (latest PHMSA referenced edition), Section 2.2] associated with the first nine categories for this risk analysis:

ASME B31.8S (latest PHMSA referenced edition), Section.2.2 Integrity Threat Classification.

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed. One of the causes reported by operators is "unknown"; that is, no root cause or causes were identified. The remaining 21 threats have been grouped into nine (9) categories of related failure types according to their nature and growth characteristics and further delineated by three (3) time-related defect types. The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

#### (1) Time-Dependent

- External Corrosion (EC)
- Internal Corrosion (IC)
- Stress Corrosion Cracking (SCC)
- Cyclic fatigue or other loading condition (CF)

#### (2) Stable

- Manufacturing Related Defects (MD)
  - 1 Defective pipe seam
  - 2 Defective pipe
- Construction/Welding/Fabrication Related (CT)
  - 1 Defective pipe girth weld
  - 2 Fabrication weld
  - 3 Wrinkle bend or buckle
  - 4 Stripped threads/broken pipe/coupling failure
- Equipment (EF)
  - 1 Gasket O-ring failure
  - 2 Control/Relief equipment malfunction
  - 3 Seal/pump packing failure
  - 4 Miscellaneous

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**(3) Time-Independent**

- Third Party/Mechanical Damage (3PD)
  - 1 Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
  - 2 Previously damaged pipe (delayed failure mode)
  - 3 Vandalism
- Incorrect Operations (IO)
  - 1 Incorrect operational procedure
- Weather Related and Outside Force (WE)
  - 1 Cold weather
  - 2 Lightning
  - 3 Heavy rains or floods
  - 4 Earth Movements

**(4) All Other Potential Threats**

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has a third party damage dent. KPC utilized the following example matrix to assist the consideration of interactive threat analysis of each HCA:



# SECTION 3 Identify Threats, Data Integration, and Risk Assessment

Form 3.1 – Interactive Threats

	EC	IC	SCC	MD	CT	EF	3PD	IO	WE	CF
EC				X			X		X	X
IC	X*			X			X			
SCC										
MD							X			
CT				X			X			
EF										
3PD	X*	X		X	X				X	X
IO										
WE							X			X
CF							X		X	

\*Interactive threats are listed by reading the Column entries. For example, for the Column EC (External Corrosion), two interactive threats are shown – IC (Internal Corrosion) and 3PD (Third Party Damage).

Historically, metallurgical fatigue has not been a significant issue for gas pipelines. However, if operational modes change and pipeline segments operate with significant pressure fluctuations, KPC will consider fatigue as an additional factor.

KPC shall consider each threat individually, interacting, or in the nine categories when following the process selected for each pipeline system or segment.

The model is periodically updated whenever changes occur affecting the HCA attributes, identified site, or additional HCAs are identified. Gathering the input data, analyzing the nature and potential for interacting threats to the pipeline, ensuring consistent relative weighting factors are assigned, is the responsibility of the Risk Management Team. A slightly modified Muhlbauer risk ranking model was utilized, with plans for continuous improvement and refinement.



## SECTION 3

# Identify Threats, Data Integration, and Risk Assessment

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The output of the risk assessment model identifies the nature and location of the most significant anticipated risks, thereby allowing identified HCA segments to be risk ranked, prioritized, and scheduled for assessment accordingly. The model output may also indicate areas needing to employ additional preventive and mitigative measures as well as improvements to the Model itself. As additional pertinent data become available, the risk assessment will be updated to determine the effects, if any, on HCA segment rankings, subsequent assessments and other relevant measures to increase overall pipeline integrity.

After the risk model is run, the Risk Management Team will review the results for reasonableness. The review will primarily be a check of the reasonableness of the relative risk ranking of the segments in the IMP. Data will be re-verified if necessary.

The integrity management rule also requires that the operator must consider all information relevant to determining risk associated with pipeline operation that could affect HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. A list of some of the more important information that KPC will consider in an integrated manner is provided below:

- Results of previous integrity assessments, defect type and size that the assessment method can detect, and defect growth rate;
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness);
- Leak and incident history, repair history, and cathodic protection history (on covered segments and non-covered segments that share a similar operational, maintenance and corrosion history);
- Operating stress level;
- Information related to determining the potential for, and preventing damage due to excavation, including damage prevention activities, and development or planned development along the pipeline;
- Population density;
- Proximity of the population to the pipeline taking into account man-made or natural barriers that might provide protection;
- Proximity of the potential event to population with limited mobility (hospitals, schools, child-care facilities, recreational facilities, prisons) particularly in unprotected facilities;
- Property damage;
- Environmental damage;
- Effects of un-ignited gas releases;
- Public convenience and necessity;
- Potential for secondary failures;
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
- Geo-technical hazards;
- Physical support of the segment such as by a cable suspension bridge;

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- Corrosion control information (e.g., test station readings, close interval survey results);
- Operating parameters (e.g., maximum operating pressure, pressure cycle history);
- Information critical to determining the potential for, and prevention of, damage due to excavation;
- Data gathered in conjunction with inspections, tests, surveillance, and patrols, including corrosion control monitoring and cathodic protection (CP) surveys;
- Information about how a failure would affect a HCA; and
- Data gathered through near miss and incident investigations.

### **3.2 Data Gathering and Integration**

The Integrity Management Plan including the threat identification is an iterative process that involves data gathering and organizing and completion of the risk assessment of each threat and for each of the pipeline segments. KPC will collect, manage, and integrate existing data and information on the entire pipeline that could be relevant to covered segments and non-covered segments where applicable. Integrating newly arising information, applicable threats, and risks (including completed prevention and mitigation actions) that may require changes to the segment prioritization or assessment method is the responsibility of the Risk Management Team and will be performed annually unless the newly identified threats require immediate modification of the BAP. Typical data sources for pipeline integrity program include:

- Process and instrumentation drawings (P&ID)
- Pipeline alignment drawings
- Original construction inspector notes/records
- Pipeline aerial photography
- Facility drawings/maps
- As-built drawings
- Material certifications
- Survey reports/drawings
- Safety related condition reports
- Operator standards/specifications
- Industry standards/specifications
- O&M procedures
- Emergency response plans
- Inspection records
- Test reports/records
- Incident reports
- Compliance records
- Design/engineering reports
- Technical evaluations
- Manufacturer equipment data

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### 3.3 Risk Assessment

The risk assessment that KPC will utilize is an analytical process by which KPC will evaluate its pipeline for various conditions that can affect pipeline integrity and the impacts or consequences that could occur following a pipeline leak or failure. This process involves gathering data on the design, construction, operation, maintenance, testing, inspection and other information about the pipeline system (including non-covered segments with similar coating and environmental characteristics). Additional industry wide data may also be obtained for data input into the risk model. These data are then combined and evaluated by the RMT utilizing a risk ranking model to determine the probability and consequence of failure for each defined HCA pipeline segment. The risk model will be capable of calculating relative ranking of risk factors associated with the likelihood of failure and the consequence of failure of a pipeline segment whenever KPC identifies multiple segments containing HCAs.

Risk based analysis of the pipeline and all associated facilities (storage field, meter and regulator stations, compressor stations, sales stations, etc.) will be performed using the following criteria:

#### Design data

Data may be gathered from original and revised drawings and specifications if available otherwise a site visit will provide much information. Design data includes:

- Design operating pressure
- Normal operating pressure
- Operating temperature
- Pipe data, including manufacturer wall thickness, grade, notch toughness, and manufacturing process
- Material compatibility
- Appurtenance data (flanges, fittings, etc.) including ANSI pressure ratings
- Piping location – above ground or below ground
- Piping connections – welded, flanged, or threaded
- Valves – manual, electric, or hydraulic operators
- Coating
- Relief devices
- Protective devices – control valves, pressure switches, and level alarms
- Oil/Water separators, scrubbers, drips
- Auxiliary piping and instrumentation tubing
- Equipment seals and seal leak containment
- Distances from equipment and piping to property lines
- Foreign Pipeline Crossings

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**Corrosion data**

Information must also be gathered about the nature and effectiveness of corrosion control.

Data Includes:

- Pipe coating, type, age, condition
- Corrosion mechanism and monitoring results
- Pipe insulation, type, age, condition
- Cathodic protection system, age, and condition
- Close interval survey results
- Aboveground paint and coating systems

**Security information**

Information includes:

- Fences
- Lighting
- Surroundings
- Visibility
- Signage

**Physical environment**

Information Includes:

- Soil types
- Soil gas surveys

**Information about environmental concerns near the facility**

- Population in vicinity
- Public Buildings
- Industrial Sites
- Public Roads and Highways
- Evacuation routes
- Commercially navigable waterways

**Information about the operating characteristics of the facility**

- Normal operating pressures
  - Man/unmanned status
  - Operating procedures
  - Frequency of facility visual inspections
  - Operator training
  - Operating error and near miss history
  - Preventive maintenance records
  - Pipe inspection reports
  - Equipment failure reports
  - Encroachments
-

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**Emergency response at the facility**

- Firefighting capability at facilities, including equipment and training
- Local fire departments, capabilities and location

The RMT concludes that of all potential threats listed in **SECTION 3.1** above that could affect these HCAs, corrosion and third party/mechanical damage would be the greatest threats. For unknown attributes, the highest risk condition was assigned. Many preventative and mitigative measures have been implemented over the years in accordance with the KPC Damage Prevention Procedures, and Operations & Maintenance Manual. An ongoing process to identify other measures is part of the IMP annual review. All recommended measures will be evaluated and a priority schedule developed. Highest priority measures include rebuilding or replacing main line block valves, installing new signs, painting all aboveground pipe, coating below ground to above ground risers, replacing gaskets, packing and diaphragms on the facility equipment, valves and regulators upgrade or replacement, implementing a GIS system, installation of additional RTU's and mainline emergency valves, installation of additional CP test leads, purchasing improved updated equipment (Flame Ionization Gas Leak Detector, ultrasonic (UT) instrument for measure remaining wall thickness), assuring adequate inventory for emergency repair sleeves / pre-tested pipe, and bonding/strapping dresser coupled pipe joints.

The RMT considered the following in their risk assessment analysis of the HCAs:

- Prioritization of pipelines/segments for scheduling integrity assessments and mitigating action;
- Assessment of the benefits derived from mitigating action including additional previous mitigating actions taken;
- Cost/benefit analysis. Unnecessary if improvements were required for assuring compliance and operational safety;
- Determination of the most effective mitigation measures for the identified threats (RMT determined the current damage prevention program and cathodic protection program to be the most effective mitigation measures for the identified threats. In general, KPC continuously strives to improve management, training and record keeping measures as necessary to assure identified threats are effectively identified and appropriate mitigation measures implemented;
- Assessment of the integrity impact from modified inspection intervals (not relevant – no modifications made to current inspection intervals);
- Assessment of the use of or need for alternative inspection methodologies (KPC has no plans to utilize alternative inspection methodologies at this time);
- More effective resource allocation (to be evaluated as additional operating and inspection data becomes available).

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### **3.4 Validation of Risk Assessment**

After the risk model is run, the Manager (or designee) and the Risk Management Team will review to assure the results are logical and consistent with KPC's and other industry experience. The review will primarily be a check of the reasonableness of the relative risk ranking of the segments in the IMP. Data will be re-verified if necessary.

### **3.5 Plastic Transmission Pipeline**

KPC does not operate any plastic transmission pipelines.

**ATTACHMENT C2**

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- Relocating the Pipeline

Review of data may show susceptibility to certain types of outside force damage. Outside force damage is a time independent threat, even with the absence of any of these indicators, and can occur at any time. Therefore, strong prevention measures are necessary, especially in areas of concern.

Observance of outside force damage is accomplished during patrols and leak surveys conducted as required by the operations and maintenance procedures. This damage may be evident in the case of heavy rains, drought conditions causing earth movement, or earthquake activity. KPC will investigate suspicious indications discovered by inspections that cannot be directly interpreted but may be correlated with weather related or seismic events. Mitigation of outside force damage is through preventative actions or repair of damage found as a result of inspections, examinations, or tests performed.

## 8.6 Corrosion

KPC's Operation and Maintenance Plans' Corrosion Control Procedures addresses actions that are taken to minimize the threat due to corrosion for both covered and non-covered segments. This section further addresses the corrosion threat in terms of both methods of integrity assessment and mitigation.

The data sets described in **SECTION 3.1** should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing a risk assessment analysis and for special considerations such as identifying severe situations requiring more or additional activities. Data is gleaned from sources such as:

- Corrosion control information (e.g., test station readings, close interval survey results)
- Leak and incident history, repair history, and cathodic protection history (on covered and non-covered segments that share a similar operational, maintenance and corrosion history)

Review of the data may show susceptibility to certain types of corrosion damage. This review will also consider pipeline segments with similar material coating and environmental characteristics. [§192.917(e)(5)] A schedule will be established by the RMT for evaluating and remediating, as necessary, deficiencies found in both the covered segment and similar segments (same type coating, soil conditions, age of pipe, etc.). The same process as established in KPC's operating and maintenance procedures under Part 192 for testing and repair will be followed. [§192.917(e)(5)]

**ATTACHMENT C3**

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### 3.3 Risk Assessment

The risk assessment that KPC will utilize is an analytical process by which KPC will evaluate its pipeline for various conditions that can affect pipeline integrity and the impacts or consequences that could occur following a pipeline leak or failure. This process involves gathering data on the design, construction, operation, maintenance, testing, inspection and other information about the pipeline system (including non-covered segments with similar coating and environmental characteristics). Additional industry wide data may also be obtained for data input into the risk model. These data are then combined and evaluated by the RMT utilizing a risk ranking model to determine the probability and consequence of failure for each defined HCA pipeline segment. The risk model will be capable of calculating relative ranking of risk factors associated with the likelihood of failure and the consequence of failure of a pipeline segment whenever KPC identifies multiple segments containing HCAs.

Risk based analysis of the pipeline and all associated facilities (storage field, meter and regulator stations, compressor stations, sales stations, etc.) will be performed using the following criteria:

#### Design data

Data may be gathered from original and revised drawings and specifications if available otherwise a site visit will provide much information. Design data includes:

- Design operating pressure
- Normal operating pressure
- Operating temperature
- Pipe data, including manufacturer wall thickness, grade, notch toughness, and manufacturing process
- Material compatibility
- Appurtenance data (flanges, fittings, etc.) including ANSI pressure ratings
- Piping location – above ground or below ground
- Piping connections – welded, flanged, or threaded
- Valves – manual, electric, or hydraulic operators
- Coating
- Relief devices
- Protective devices – control valves, pressure switches, and level alarms
- Oil/Water separators, scrubbers, drips
- Auxiliary piping and instrumentation tubing
- Equipment seals and seal leak containment
- Distances from equipment and piping to property lines
- Foreign Pipeline Crossings

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**Corrosion data**

Information must also be gathered about the nature and effectiveness of corrosion control.

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- Pipe insulation, type, age, condition
- Cathodic protection system, age, and condition
- Close interval survey results
- Aboveground paint and coating systems

**Security information**

Information includes:

- Fences
- Lighting
- Surroundings
- Visibility
- Signage

**Physical environment**

Information Includes:

- Soil types
- Soil gas surveys

**Information about environmental concerns near the facility**

- Population in vicinity
- Public Buildings
- Industrial Sites
- Public Roads and Highways
- Evacuation routes
- Commercially navigable waterways

**Information about the operating characteristics of the facility**

- Normal operating pressures
  - Man/unmanned status
  - Operating procedures
  - Frequency of facility visual inspections
  - Operator training
  - Operating error and near miss history
  - Preventive maintenance records
  - Pipe inspection reports
  - Equipment failure reports
  - Encroachments
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**Emergency response at the facility**

- Firefighting capability at facilities, including equipment and training
- Local fire departments, capabilities and location

The RMT concludes that of all potential threats listed in **SECTION 3.1** above that could affect these HCAs, corrosion and third party/mechanical damage would be the greatest threats. For unknown attributes, the highest risk condition was assigned. Many preventative and mitigative measures have been implemented over the years in accordance with the KPC Damage Prevention Procedures, and Operations & Maintenance Manual. An ongoing process to identify other measures is part of the IMP annual review. All recommended measures will be evaluated and a priority schedule developed. Highest priority measures include rebuilding or replacing main line block valves, installing new signs, painting all aboveground pipe, coating below ground to above ground risers, replacing gaskets, packing and diaphragms on the facility equipment, valves and regulators upgrade or replacement, implementing a GIS system, installation of additional RTU's and mainline emergency valves, installation of additional CP test leads, purchasing improved updated equipment (Flame Ionization Gas Leak Detector, ultrasonic (UT) instrument for measure remaining wall thickness), assuring adequate inventory for emergency repair sleeves / pre-tested pipe, and bonding/strapping dresser coupled pipe joints.

The RMT considered the following in their risk assessment analysis of the HCAs:

- Prioritization of pipelines/segments for scheduling integrity assessments and mitigating action;
- Assessment of the benefits derived from mitigating action including additional previous mitigating actions taken;
- Cost/benefit analysis. Unnecessary if improvements were required for assuring compliance and operational safety;
- Determination of the most effective mitigation measures for the identified threats (RMT determined the current damage prevention program and cathodic protection program to be the most effective mitigation measures for the identified threats. In general, KPC continuously strives to improve management, training and record keeping measures as necessary to assure identified threats are effectively identified and appropriate mitigation measures implemented;
- Assessment of the integrity impact from modified inspection intervals (not relevant – no modifications made to current inspection intervals);
- Assessment of the use of or need for alternative inspection methodologies (KPC has no plans to utilize alternative inspection methodologies at this time);
- More effective resource allocation (to be evaluated as additional operating and inspection data becomes available).

**ATTACHMENT D1**

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## **8.1 General Requirements (Identification of Additional Measures)**

KPC will take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a High Consequence Area. [§192.935(a)]

Preventive and Mitigative measures are generally non-prescriptive measures that may be selected for implementation as a result of evaluation and analysis of its cost and level of risk reduction in relation to other activities.

After the results of the HCA identification and risk assessment are available, the next step is to consider other opportunities to more efficiently control risks and determine what preventive or mitigative actions might be desirable. Identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by §192.917. The risk control and mitigation evaluation process involves the following steps:

- Identification of risk control options that lower the likelihood of a pipeline system incident (preventive)
- Reduce the consequences (mitigative activities)
- Systematic evaluation and comparison of those options to quantify the risk reduction impact
- Selection and implementation of the optimum strategy for risk control.

In order to find the optimum approach to risk control, it is important that a variety of options, and perhaps combinations of activities, be considered, rather than just taking the first idea that is proposed or continuing what has been standard practice. This allows for the consideration of innovative solutions and new technologies that may be more effective in addressing risk.

The KPC Integrity Management Plan includes mitigation activities to prevent, detect, and minimize the consequences of unintended releases. Mitigation activities do not necessarily require justification through additional in-line inspection data. Mitigative actions can be identified during normal pipeline operation and maintenance activities, during the initial risk assessment, during implementation of the baseline inspection plan, or during subsequent testing.

A spectrum of alternative measures exists such as, but not limited to:

- Installing Automatic Shut-off Valves or Remote Control Valves,
- Installing computerized monitoring and leak detection systems,
- Replacing pipe segments with pipe of heavier wall thickness,
- Providing additional training to personnel on response procedures,
- Conducting drills with local emergency responders and
- Implementing additional inspection and maintenance programs. [§192.935(a)]

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Suggested mitigation and prevention activities to consider are presented in tables in **APPENDIX E** titled 'Risk Matrix, Considerations of Options for Mitigative, P&M Measures Selection Flow Charts'. This matrix will allow for initial selection of appropriate measures that can be considered based on pipeline risk factors. This matrix lists specific action items that can be used as a preventive or mitigative action item to reduce risk to an HCA that can be affected by a leak from a pipeline segment.

The tables in **APPENDIX E** provide the considerations made by KPC while determining the feasibility of each of the listed measures. The following factors are noted relative to each measure within the tables:

Factor	Description
Benefit	Benefits related to reducing threat.
Cost	A relative ranking (significant, moderate, minor) of the cost associated with the implementation of the measure.
Effect to Public	The effect the implementation of the measure would have to the public.
Difficulty	Is it difficult to implement the measure (Not Difficult, Moderate, Very Difficult).
Feasibility	Based on the factors above (Very Feasible, Moderately Feasible, Low Feasibility)

The RMT shall identify threats that pertain to the KPC HCA's by the following procedures.

#### **Identify Common Threats**

Common Threats are those threats that are present to all HCA's. Their mitigations can be addressed through mitigation actions applied uniformly across all segments. The following procedure shall be used to identify Common Threats.

1. Obtain the tabulated results of the recently completed risk assessments.
2. Review Failure Likelihood Scores of each segment to determine which threats are the most significant to each segment. Identify the top 2 threats for each segment.
3. Review all segments to determine where trends exist. Determine which segments have the same top 2 threats.
4. Record these threats as Common Threats in **FORM 8.1**.

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### Identify Segment Specific Threats

Segment Specific Threats are those threats that are identified as significant to a limited subset of the segments. Their mitigations can be addressed through focused mitigative actions applied only to the subset. The following procedure shall be used to identify Segment Specific Threats:

- Review Failure Likelihood Score of each segment to determine if there are segments in which the top 2 threats for those segments are not the same as the top 2 threats identified in the Common Threats identification process.
- Record these threats as Segment Specific Threats in **FORM 8.1**.

### Selection of Measures for Common and Segment Specific Threats

After defining the threats that are relevant to the KPC HCA's, the Pipeline Integrity Engineer and Field Operations Manager shall:

- Review the measures of **APPENDIX E** that have been defined as Moderately Feasible and Very Feasible.
- Select appropriate preventative measures to be applied to Common Threats and Segment Specific Threats. The measures shall be selected which will have the greatest impact and are the most feasible. Record the selected preventative measures in **FORM 8.1**.

### Consequences of Pipeline Failures

The consequences of a failure must be reviewed, considering the impact the event will have to the public, the environment, and business operations. The impact is quantified in the calculation of a Consequence Score. The threat Identification and Risk Assessment procedure, details the method used to calculate the Consequence Score. Consideration is given to the nine factors defined in AMSE B31.8S (Latest PHMSA Referenced Edition), Section 3.3 through this scoring algorithm.

The overall risk of failure of any one segment is managed through adjusting inspection and maintenance frequencies, as the potential consequence of failure of that segment increases. To ensure that P&M measures are applied to those segments with the greatest consequence of failure, the RMT shall use the Consequence Scores to prioritize the preventative and mitigative measures.

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### Implementation of P&M Measures

Schedule for Implementation:

The RMT shall prioritize the implementation of P&M measures based on the Consequence Scores. P&M measures identified for the segments with the highest Consequence Scores shall be scheduled for completion first. This schedule shall be recorded in **FORM 8.1**. The record shall be made available annually for use in the revaluation of the pipeline Risk Assessments and P&M measure effectiveness.

This schedule will then be reviewed annually for adjustment as necessary based on the determination of effectiveness as well as the potential for new techniques or conditions along the ROW.

## 8.2 Third Party Damage

This section addresses the threat, and methods of integrity assessment and mitigation for third party damage. Third party damaged is defined in this context as third party inflicted damage with immediate failure, vandalism, and previously damaged pipe. This section outlines the integrity management process for third party damage in general, and also covers some specific issues.

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. Implementation of enhancements to the Damage Prevention Program (§192.614) with respect to covered segments to prevent and minimize the consequences of a release must be considered and should include:

- Qualified personnel (§192.915(c)) must be used for work being conducted that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [§192.935(b)(1)(i)]
- Overseeing the collecting, in a central database, location-specific information on excavation damage that occurs in covered and non-covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas is the responsibility of KPC. This information must also include recognized damage that is not required to be reported as an incident under Part 191. [§192.935(b)(1)(ii)] This data is collected in support of performing the risk assessment analysis, and for special considerations such as identifying severe situations requiring more or additional activities. Enhanced measures include, at a minimum:
  - Vandalism incidents
  - Pipe inspection reports (bell hole) where the pipe has been hit
  - Leak reports resulting from immediate damage
  - Incidents involving previous damage
  - In-line inspection results for dents and gouges at top half of pipe

**ATTACHMENT D2**

	<b>integrity Management Program</b>	
	<b>SECTION 8</b> <b>Preventive and Mitigative Measures</b>	PAGE NUMBER 8-8  LAST REVISION DATE October 31, 2012

## **8.7 Automatic Shut-Off Valves or Remote Control Valves**

Automatic shut-off valves or remote control valves (ASVs / RCVs) represent an efficient means of adding protection to potentially affected High consequence Areas. [§192.935(c)] One of the alternative action items to consider minimizing the consequences of a leak is to install either an automatic shut-off valve or a remote control valve. These devices that can limit the amount of gas released as a result of a leak or rupture. If either one of these devices is considered for use as a mitigative measure, the decision to use it must include the following factors:

- Swiftens of leak detection and pipe shutdown capabilities
- Type of gas being transported
- Operating pressure
- Rate of potential release
- Pipeline profile
- Potential for ignition
- Location of nearest response personnel

The RMT will conduct the risk reduction analysis to determine if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. The Manager (or designee) will review the recommendation, and will approve / disapprove the proposed recommendation. If the decision is not to approve installation, justification based on an engineering analysis must be documented.

## **8.8 General Requirements (Implementation of Additional Measures)**

The decision-making process that is in place to decide which measures are to be implemented involves input from all employees of the organization and the RMT. Outside sources, as necessary, will be contracted to augment areas of expertise not available within the organization. [§192.935(a)]

**ATTACHMENT E**

	<b>Integrity Management Program</b>	
	<b>SECTION 11</b> <b>Management of Change</b> <b>(MOC)</b>	PAGE NUMBER 11-1  LAST REVISION DATE October 31, 2012

## **11.1 Documentation and Notification of Changes to the Integrity Management Program**

Changes to the Integrity Management Program must be documented in accordance with §192.909. The reasons for program changes must be documented prior to implementation of the change(s) [§192.909(a)] and, for significant changes to the program, program implementation, or schedules, OPS must be notified within 30 days after the adopted the change. [§192.909(b)]

## **11.2 Attributes to the Change Process**

Formal management of change (MOC) procedures has been developed in order to identify and consider the impact of changes to the KPC pipeline systems and their integrity prior to implementing the change. The MOC process must be used for both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural and organizational changes to the system whether permanent or temporary.

The MOC process includes the following:

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

Any system changes can require changes in the Integrity Management Program and conversely, results from the program can cause system changes. The following are examples that are gas pipeline specific but are by no means all-inclusive:

- If a change in land use would affect either the consequence of an incident such as increases in population near the pipeline, or a change in likelihood of an incident such as subsidence due to underground mining, the change must be reflected in the Integrity Management Plan and the threats reevaluated accordingly.
- If the results of an Integrity Management Program inspection indicate the need for a change to the system, such as changes to the CP program or, other than temporary, reductions in operating pressure, these shall to be communicated to the IMT and reflected in an updated Integrity Management Program.

	<b>Integrity Management Program</b>	
	<b>SECTION 11</b>	
	<b>Management of Change (MOC)</b>	
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- If a decision is made to increase pressure in the system from its historical operating pressure to or closer to the allowable MAOP, that change shall be reflected in the integrity plan and the threats shall be reevaluated accordingly.
- If a line has been operating in a steady state mode and a new load on the line changes the mode of operation to a more cyclical load (e.g. daily changes in operating pressure), fatigue shall be considered in each of the threats where it applies as an additional stress factor.

Along with Management, the review procedure should require involvement of applicable staff that can assess safety impact, and if necessary, suggest controls or modifications.

Management of Change ensures that the Integrity Management process remains viable and effective as changes to the system occur and/or new, revised or corrected data becomes available. Any change to equipment or procedures has the potential to affect pipeline integrity. Most changes, however small, will have a consequent effect on another aspect of the system. For example, many equipment changes will require a corresponding technical or procedural change. All changes shall be identified and reviewed before implementation. Management of Change procedures provide a means of maintaining order during periods of change in the system, and helps to preserve confidence in the integrity of the pipeline.

System changes, particularly in equipment, may require qualification of personnel for the correct operation of the new equipment. In addition, refresher training should be provided to ensure that facility personnel understand and adhere to the facility's current operating procedures.



**ATTACHMENT F**

	<b>Gas Pipeline Integrity Management Program</b>	
	<b>Introduction</b>	
	PAGE NUMBER Intro - 3	LAST REVISION DATE October 31, 2012

KPC operates the gas transmission pipelines from its office in Olathe, Kansas. The Managers of KPC are responsible for the pipelines and their operation. The field technicians perform the day-to-day operation and maintenance of the pipeline. The Area Management and field technicians are on available for duty seven days per week. A Pipeline Consulting Engineer is available as needed to provide technical advice for the pipeline. A 24-hour Gas Control takes any calls from the public, and notifies the KPC personnel of any need to attend to the pipeline after-hours.

The final effective date of the DOT integrity management rule was December 15, 2003. For any existing or newly constructed pipeline, the effective date for compliance would be the date the pipeline was placed in service. KPC must assure that a baseline assessment of any newly-installed segments of pipe between December 15, 2003 and November 2009 that is covered by this subpart is completed within ten (10) years from this effective date or the installed date. Compliance dates within DOT's Integrity Management Rule for pipeline operators of jurisdictional pipeline are:

Industry Standards noted in this plan are those cited in the original Integrity Management rule. KPC will adopt and follow the most current Industry Standards that have been referenced in this plan and that have been incorporated by reference by PHMSA in 49 CFR Part 192.



# Introduction

## Integrity Management Compliance Dates

8/31/ 2004	An Operator must report to OPS indicating KPC has begun its preliminary assessments. Thereafter, an Operator must submit full reporting to OPS of the four overall performance measures using annual reports (Form PHMSA 7100.2.1) submitted each year, no later than March 15, for the preceding calendar year in accordance with §192.945.
12/17/2004	<p>An Operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment.</p> <p>The initial integrity management program must consist, at a minimum, of a framework that describes for each of the 16 elements identified in §192.911:</p> <ul style="list-style-type: none"><li>• The process for implementing each program element,</li><li>• How relevant decisions will be made and by whom,</li><li>• A schedule for completing the work to implement each program element, and</li><li>• How the information gained from experience will be continuously incorporated into the program.</li><li>• This framework will evolve into a more detailed and comprehensive program.</li></ul>

## KPC Pipeline, LLC Company Information

<b>KPC Pipeline, LLC</b>	19970 W. 161 <sup>st</sup> Street Olathe, KS 66062
<b>DOT Program Consultant</b>	The Compliance Group KW Pritchett Shelli Myers

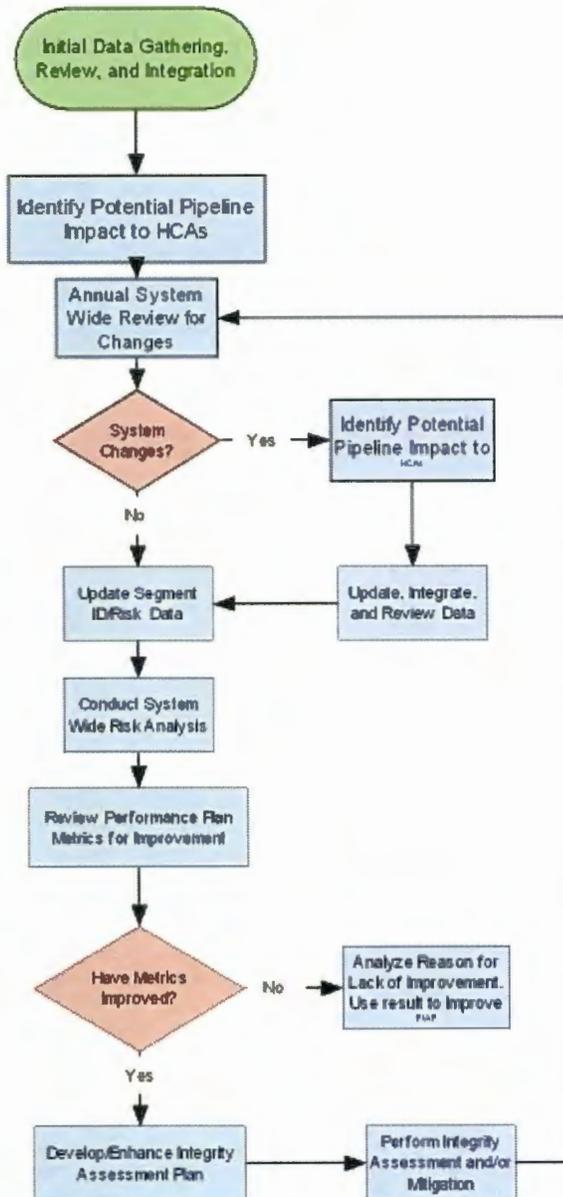
The **Managers** are responsible for approval of major maintenance activities, design, construction, corrosion control, operations and Pipeline Integrity Management Programs.

The **Program Coordinator (Senior Pipeline Inspector)** insures compliance with regulatory mandates, including field coordination of the integrity management process and integrity data integrations.

The **Risk Management Team (RMT)** consists of the Program Coordinator, Field Operation Managers, Site Managers, Integrity Management Program Consultant and DOT Program Consultant.

**Integrity Programs Goals**

**Figure II**  
**Pipeline Integrity**  
**Management**  
**Process**  
**Flowchart**



	<b>Gas Pipeline Integrity Management Program</b>	
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### **Organizational Responsibilities**

The Managers have overall responsibility for development and effectiveness of the integrity management plan and will:

- Determine required documentation
- Review the programs annually and make recommendations for improvement
- Verify that personnel involved in the plan are properly trained
- Arrange for internal or third party audits of the program
- Documentation of activities required by the plan
- Assigning trained persons to tasks required by the plan
- Supervision of persons engaged in tasks required by the plan
- Communications with OPS, including semi-annual reports of performance metrics

The RMT will meet as necessary to implement the provisions of the IMP. The team will also evaluate internal risk management processes and conduct benchmarking of industry peers to identify and apply "best practices". The team will also evaluate and confirm that processes identified and recommended for implementation are aligned with the KPC business plan. If the results are not consistent with the KPC's understanding and expectations of system operation and risks, KPC management will explore the reasons why and make appropriate adjustments to the method, assumptions, or data. The RMT's responsibilities include:

- Implement risk management processes
- Develop procedures for risk management application
- Administration of the Risk Based Index (RBI) model
- Review, updating and upgrading of the RBI model components

Other critical responsibilities of the Risk Management Team are to:

- Develop data management processes
- Communication and distribution of the RBI model and results
- Continual verification and validation of the risk model results
- Self-auditing of KPC for proper and timely application of the processes, and identification of better practices.

**ATTACHMENT G**

	<b>Integrity Management Program</b>	
	<b>SECTION 13</b>	
	<b>Communications Plan</b>	
	PAGE NUMBER 13-2	
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## 2. Local and Regional Emergency Responders

- Operator should maintain continuing liaison with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.
- Company name and contact numbers both routine and emergency.
- Local maps.
- Facility description and commodity transported.
- How to recognize, report, and respond to a leak.
- General information about KPC's prevention and integrity measures and how to obtain summary of Integrity Management Plans.
- Station locations and descriptions.
- Summary of operators' emergency capabilities.
- Coordination of operators' emergency preparedness with local officials.

## 3. General Public

- Information regarding operator's efforts to support excavation notification and other damage prevention initiatives.
- Company name, contact, and emergency reporting information including general business contact.

KPC will vigorously pursue any opportunity to have some dialogue with the public in order to convey confidence in the integrity of the KPC pipeline as well as to convey KPC's expectations of the public as to where they can help maintain integrity. Such opportunities should be taken advantage of in order to help protect assets, people, and the environment.

KPC's management and other appropriate personnel understand and support the Integrity Management Program. This buy-in is being accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures reviewed on a periodic basis (RMT meetings) and resulting adjustments to the Integrity Management Program are an integral part of the internal communications plan.

### 13.2 Addressing Safety Concerns

KPC has always placed a high priority on safety and compliance. KPC embraces the goals of improving pipeline safety and raising the public confidence with pipelines as it continues to ensure safe operations of its infrastructure. Any safety concerns noted by the PHMSA or state Pipeline Safety Authorities will be promptly addressed by the IMT to assure continued safe operation and compliance of the KPC pipeline system.

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