genesisenergy

May 23, 2012

Mr. Wayne Lemoi
Director, Southern Region, PHMSA
Pipeline and Hazardous Materials Safety Administration
233 Peachtree Street NE, Suite 600
Atlanta, GA 30303

RE: CPF 2-2012-5002M
Genesis Pipeline USA, L.P. (Genesis) Audit, November 2, 2011 – February 16, 2012
Response to Notice of Amendment, April 19, 2012

FedEx Tracking No.: 798431283835

Dear Mr. Lemoi:

A comprehensive safety evaluation was performed on pipeline facilities operated by Genesis Pipeline USA, L.P. (Genesis), from November 2, 2011 to February 16, 2012. As an outcome of the inspection, alleged inadequacies were identified relative to the Genesis Liquid Operations, Maintenance, and Emergency Procedures Manual referred to as the LOM&E Manual. In response, Genesis is proposing an amendment to 17 items identified within the LOM&E Manual in accordance with Title 49 CFR 195.

Item 1 – Revisions made to Genesis LOM&E Manual, Section 4.6, Accident and Other Reporting

- Paragraph "*Telephonic Notice*", includes:

  Required information for a telephonic report must include:

  1. Name, Operator ID Number, and address of operator.

Item 2 – Revisions made to Genesis LOM&E Manual, Section 3.1, Reporting Safety Related Conditions:

- Paragraph "*Safety Related Condition*", includes:

  2. Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, subsidence, geologic creep, slump, or flood that impairs its serviceability.

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Item 3 – Revisions made to Genesis LOM&E Manual , Section 3.1, *Reporting Safety Related Conditions:*

- Paragraph *"Safety Related Condition"*, includes:

  6. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in nominal operating pressure or shutdown of operation of a pipeline.

Item 4 – revisions made to Genesis LOM&E Manual, Section 3.1, Reporting Safety Related Conditions:

- Paragraph *"Reporting a Safety Related Condition, When to Report"* includes:

  - Is an accident that is required to be reported under §195.50 or results in such an accident before the deadline for filing the safety-related condition report; or
  - Is not corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report (See "Deadline for Reporting" below), except that reports are required for all conditions under paragraph 195.55(a) (1), See "Safety Related Conditions" above of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

Item 5 – Revisions made to Genesis LOM&E Manual, Section 3.1, Reporting Safety Related Conditions:

- Paragraph *"Reporting a Safety Related Condition, Documentation"* includes:

  All safety-related condition evaluations must incorporate the date of discovery, filing date, and documented accordingly.

  Note: The Safety Related Condition Report example at the back of Section 3.1 now includes filing and discovery date.

Item 6 – Revisions made to Genesis LOM&E Manual, Section 2.17 Manual, Pipeline Integrity Testing:

- Paragraph "*Conducting the Test*" includes:

  If the pressure decreases, test medium may have to be added. A pressure decrease may indicate a temperature decrease or a leak. See Genesis Hydrotest Standard 1000, Section 10.0, Pressure-Temperature-Volume Relationships, for determining if a volume change can be attributed to a temperature change. If a volume change cannot be attributed to a temperature change, suspect a leak.

  If the pressure increases, test medium may have to be removed to avoid over pressuring the pipe, especially at low elevations. A pressure increase probably indicates a temperature increase. When removing the test medium, be sure that the pressure does not fall below the required test pressure.

  Important Point: Record the volume of any test medium that is added or removed.

  See "Genesis Hydrotesting Standard 1000", Section 10.0, Pressure-Temperature-Volume Relationships

  Deviations in pressure, especially during the leak test phase of the pressure test, can sometimes be explained as a result of changes in the temperature of the environment. Refer to AS/NZS 2885.5:2002 *Australian/New Zealand Standard "Pipelines – Gas and Liquid Petroleum, Part 5: Field Pressure Testing"* for a method to determine the impact on pressure and volume due to variations in temperature.

Item 7 – Revisions made to Genesis LOM&E Manual, Section 2.3, *Immediate Response P/L Identification* includes:

Genesis' Integrity Management Plan details which pipeline facilities are located in high consequence areas, or areas requiring an immediate response in order to prevent hazards to the public if the facilities failed or malfunctioned. Pipelines requiring immediate response will be listed in Section 10.0, *Pipeline Segment Status Reports*.

High Consequence Areas (HCA's), as determined through the Asset Integrity Management defines the pipeline segments and facilities that would require an immediate response by the operator to prevent hazards to the public. Maps and/or records as provided by Company personnel or third party companies indicating these areas may be located with the Local Operating Office, on strip maps, third party "as built" maps, and/or other drawings (P& I D drawings, Local Operations Isometrics, etc.).

Item 8 - Revisions made to Genesis LOM&E Manual, Section 2.5, Line Markers and Signs includes,

- Paragraph *Visibility, Exceptions*:
  Line markers are not required in the following circumstances:
  - Offshore or at crossings of or under waterways and other bodies of water; or
  - In heavily developed urban areas such as downtown business centers where
    - The placement of markers is impractical and would not serve the purpose for which markers are intended; and
    - The local government maintains current substructure records.

Item 9 – Revisions made to Genesis LOM&E Manual, Section 2.11, Breakout Tank Inspection includes:

- Paragraph "*Routine In-Service Tank Inspections*"
  - [API 653 Sections 6.3.2.1] All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every 5 years or RCA /4 N years (where RCA is the difference between the measured shell thickness and the minimum required thickness in mils, and N is the shell corrosion rate in mils per year) whichever is less. Tanks may be in operation during this inspection.

- [API 653 Sections 4.3.2.1] For determining the controlling thicknesses in each shell course when there are corroded areas of considerable size, measured thicknesses shall be averaged in accordance with procedure (see Figure 4-1) Inspection of Corrosion Areas and should be documented for follow-up action by an authorized inspector.

- [API 653 Sections 6.4.1.2] All tanks shall have a formal internal inspection conducted at the intervals defined by 6.4.2 or 6.4.3. The authorized inspector who is responsible for evaluation of a tank must conduct a visual inspection and assure the quality and completeness of the NDE results. If the internal inspection is required solely for the purpose of determining the condition and integrity of the tank bottom, the internal inspection may be accomplished with the tank in service utilizing various ultrasonic robotic thickness measurement and other on-stream inspection methods capable of assessing the thickness of the tank bottom, in combination with methods capable of assessing tank bottom integrity as described in 4.4.1. Electro-magnetic methods may be used to supplement the on-stream ultrasonic inspection. If an in service inspection is selected, the data and information collected shall be sufficient to evaluate the thickness, corrosion rate, and integrity of the tank bottom and establish the internal inspection interval, based on tank bottom thickness, corrosion rate, and integrity, utilizing the methods included in this standard. An individual, knowledgeable and experienced in relevant inspection methodologies, and the authorized inspector who is responsible for evaluation of a tank must assure the quality and completeness of the in-service NDE results.

- Alternative Internal Inspection Interval

[API 653 Sections 6.4.3]

Table 6-1 — Bottom Plate Minimum Thickness	
Minimum Bottom Plate Thickness at Next Inspection (in.)	Tank-Bottom/Foundation Design
0.10	Tank bottom/foundation design with no means for detection and containment of a bottom leak.
0.05	Tank-bottom/foundation design with means to provide detection and containment of a bottom leak.
0.05	Applied tank bottom reinforced lining
> 0.05	in accordance with API RP 652

- Genesis "*Monthly Tank/Vessel Inspection Report*" Form includes the following inspections, Section *Visual Inspection Criteria*:
  - Paint in Good Condition
  - Foundation in Good Condition
  - Tank/Vessel Appurtenances in Good Condition
  - Tank Chime in Good Condition
    - The chime is the flat plate at the bottom of a welded vertical oil storage tank.
  - No Tank Shell Distortion
  - No Damage/Dents in Tank Vessel
  - No Are there any Apparent Leaks
  - Catwalk/Ladder in Good Condition

Item 10 – Revisions made to Genesis LOM&E Manual, Section 2.1 Design & Construction, and 2.19 External Corrosion:

Section 2.1, Design & Construction

- Paragraph "*Acceptable Coating Materials*" includes:

The coating material must be constructed to mitigate corrosion, have adequate adhesion to the metal to prevent under film moisture migration, sufficiently ductile to resist cracking, strong enough to resist damage from handling or soil stresses, support cathodic protection, and if an insulating type, have low moisture absorption and provide high electrical resistance. Company approved external coating systems are as specified in *GEN CP 41, "Coatings Selection and Application"*. Joints, welds, fittings, air to soil interface, and tie-ins will be coated with materials compatible with the coatings on the pipe.

- Paragraph *"Preparation and Application"* includes:

  All existing coating in the designated sections shall be removed from the pipeline per *GEN CP 41, "Coatings Selection and Application" and GEN CP 42, Protective Coatings for New Construction and Maintenance, Onshore and Offshore Procedure"*. The Contractor shall remove coating in a manner that does not cause an unsafe condition or damage the pipe. Any method of coating removal that may scar, dent, or damage the pipe surface is strictly prohibited.

Section 2.19, External Corrosion

- Paragraph *"Coating Inspection"* includes:

  The pipe must be inspected and/or repaired just prior to lowering the pipe into the ditch or submerging the pipe to ensure there is no damage to the external coating. If coating damage is discovered, then an appropriate repair to the coating shall be conducted prior to backfill. Furthermore, the coating shall be protected from damage resulting from adverse ditch conditions, backfill or damage from supporting blocks. Coating inspection and repair procedures are included in *GEN CP 41, Coating Selection Application and Maintenance* and *GEN CP 42, Protective Coatings for New Construction and Maintenance, Onshore and Offshore Procedure.*

  - Procedural steps regarding *"Application"* are found in Section 8 of *GEN CP 42, Protective Coatings for New Construction and Maintenance, Onshore and Offshore Procedure.*

  - Procedural steps regarding *"Inspection and Quality Control"* are found in Section 9 of *GEN CP 42, Protective Coatings for New Construction and Maintenance, Onshore and Offshore Procedure.*

Item 11 - Revisions made to Genesis LOM&E Manual, Section 2.19 External Corrosion:

- Paragraph *"Inspection when the Pipe is Exposed"* includes:

  When a pipeline is exposed for any reason, it must be examined for evidence of external corrosion and repaired. If external corrosion is found, the surface of the pipe in the near vicinity must be inspected to determine the extent of the corrosion. External corrosion control shall be mitigated by referring to the *GEN CP 39, "External Corrosion Control Program"*. If external corrosion is found, requiring corrective action under 195.585, we must investigate circumferentially and longitudinally beyond the exposed pipe (by either visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the area.

  - Procedural steps regarding *"Application"* are found in Section *GEN CP 39, "External Corrosion Control Program"*

Item 12 – Revisions made to Genesis LOM&E Manual, Section 2.19 External Corrosion:

- Paragraph *"Close Interval Survey Consideration"* includes:

  To accomplish the objectives of 49 CFR 195.573 (a)(2) and paragraph 10.1.1.3 of NACE RP 0169, identify not more than 2 years after cathodic protection is installed, the circumstances in which a close interval survey or comparable technology is practical and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE SP 0169 – 2007. Each pipeline system shall be evaluated and documented per:
  - GEN CP 5, *Close Interval Survey Pipe to Soil Potential Specification*
  - *GEN CP 35, Close Interval Survey Consideration*
  - *GEN CP 36, Close Interval Survey Remedial Action Documentation.*

Item 13 - Revisions made to Genesis LOM&E Manual, Section 2.19 External Corrosion:

- Paragraph *"Electrical Isolation"* includes:

Consideration shall be given as to electrically isolating pipelines connected to facilities of other companies in accordance with 49 CFR 195.575. The electrical isolation shall be maintained, and tested by qualified personnel between facilities as is necessary to assure that electrical isolation is adequate. If an insulating device is installed in an area where there is the potential for a combustible atmosphere, precautions will be taken to prevent arcing. In addition, pipelines and insulating devices shall be protected from fault currents and lightning when tests and inspections indicate a high probability of occurrence. Depending upon site specific data and characteristics, additional monitoring and/or remediation measures regarding an electrical isolation device may be prescribed. During each corrosion control survey, a check of the integrity of insulating devices shall be made if inadequate cathodic protection levels are found. Deficiencies identified in electrical isolation will be addressed as soon as practical. Electrical isolation monitoring procedures shall be in accordance with Company specification *GEN CP 14A, "Monitoring Electrical Isolation at Connections"*.

Testing personnel should also be alert for electrical short circuits between the pipeline and casing pipe that can result in inadequate cathodic protection of the pipeline outside of the casing due to reduction of protective current to the pipeline. Any casing that measures a pipe to soil potential versus a casing to soil potential that is 100mV or less will be treated as a possible shorted casing. Documentation of the shorted section shall be reported on at each location the casing shall be tested to determine if a short exists. Procedures for testing casings for shorts are included in Company specification *GEN CP 14 "Testing for the Electrical Isolation of Casings"*.

If the test determines that a short does exist, the shorted casings vents shall be checked with a gas detector for signs of leakage at least twice each calendar year, but with intervals not exceeding 7.5 months until the short is cleared, the casing is filled with a corrosion inhibitor, or the casing is removed/replaced. If the test indicates that a short does not exist, annual monitoring of pipe to

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soil versus casing to soil potentials for any changes from previous year's survey will be sufficient.

- Buried or submerged pipelines must be isolated from other metallic structures unless they are electrically interconnected and cathodically protected as a unit.
- Insulating devices must be installed where only a portion of a pipeline being protected by current
- Isolation must be electrically tested for verification
- Precautions must be taken to avoid arcing where insulating devices are being placed in an area that could have a hazardous atmosphere
- If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or any area where fault currents may exist or lightning is a high risk, the pipeline must be protected at the insulating devices.

- Paragraph *"Monitoring Shorted Casings"* includes:

Hydrocarbon vapor monitoring must be conducted on all shorted casings twice each calendar year, at intervals not exceeding 7.5 months if casing vent is available. Refer to *GEN CP 14A, Monitoring Electrical Isolations at Connections and GEN CP 14B, "Testing for the Electrical Isolation of Casings"*

Monitoring Documentation:

All vapor monitoring must be documented. Documentation must be kept for two years and include:

- Date of monitoring
- Name of the person who performed the monitoring
- Location of the casing
- Results of the monitoring
- Date and type of corrective action taken

If no casing vent is present, aerial patrols or drive by patrols should be conducted twice each calendar year at intervals not exceeding 7.5 months.

How to Repair a Shorted Casing:

A shorted casing may be repaired by any of the following methods:

- Clear the short. This may only be practical if the short is near either end of the casing.
- Replace the crossing.
- Remove the casing if the casing is not required by railroad or transportation entities or by design parameters.
- Fill the casing with a high dielectric casing filler.

Repair Documentation:

All shorted casing repairs must be documented. Documentation must be kept for the life of the pipeline and include:

- Location of the casing
- Date and description of the repair

Atmospheric Corrosion inside Casings:

Any casing subject to the following conditions must be filled with a high dielectric casing filler or an inhibiting agent as soon as practical:

- Casing containing an uncoated or poorly coated pipeline in a *high risk area* and in an environment known to be corrosive
- Casing containing a pipeline known to have a substantial wall loss due to atmospheric corrosion

Item 14 - Revisions made to Genesis LOM&E Manual, Section 2.20 Internal Corrosion Control:

- Paragraph *"Mitigation of Internal Corrosion"* includes:

  - We must investigate the corrosive effect of any product transported that may corrode the pipeline per *GEN INT CP 1, "Internal Corrosion Control Program" and GEN INT CP 2, "Internal Corrosion Control"*. Corrective action must be taken for any hazardous liquid that is determined to be corrosive. Such actions may include:

- Injecting corrosion inhibitors - If corrosion inhibitors are used we must:

    - Use sufficient quantities to protect the entire part of the pipeline system to be protected
    - Increasing frequency of pigging
    - Applying internal coatings
    - Increasing product movement (or reducing down time or stagnant conditions)

Adequate steps, including eliminating the possibility of free water, removing corrosive components, or injecting corrosion inhibitor will be taken whenever investigation of the corrosive effect of the product on the metal indicates it is necessary. When a corrosion inhibitor is used to mitigate internal corrosion, a sufficient quantity to protect the entire part of the system the inhibitor is designed to protect will be used.

Internal Corrosion Control Monitoring:

If corrosion inhibitors are used, coupons or other monitoring equipment must be installed to determine the effectiveness of the inhibitors. Coupons or other monitoring equipment must be inspected twice each calendar year at intervals not exceeding 7.5 months. See the list of Internal Corrosion Procedures listed below under Genesis Internal Corrosion Control Program References.

Item 15 – Revisions made to Genesis LOM&E Manual, Section 2.19 External Corrosion:

- Paragraph *"Protection Against Atmospheric Corrosion"* includes:

  If the coating is damaged or ineffective, and atmospheric corrosion is found, remedial action must be taken to maintain protection against atmospheric corrosion except where it can be demonstrated by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will only be a light surface oxide or that it will not affect the safe operation of the pipeline before the next scheduled inspection (excluding portions of pipelines in offshore splash zones or soil-to-air interfaces). Company approved atmospheric coating systems are as specified in *GEN CP 40, Atmospheric Corrosion Inspections.*

- Exposed pipeline must be cleaned and coated (with exceptions listed below)
- Coating material must be suitable for the atmosphere and the pipeline
- Except for pipelines in offshore splash zones, or soil-to-air interfaces, we need not protect facilities that we demonstrate by test, investigation or experience that corrosion will only be a light surface oxide or will not affect safe operation of the pipeline before the next scheduled inspection.

    - Procedural steps regarding GEN CP 40, Atmospheric Corrosion Inspections includes:

        - Section 2.0, Procedure, Subsection 2.1-Identifying Areas for Inspection
            - Identify all above grade and above water line structures/facilitates or parts of structures/facilities as subject for atmospheric corrosion inspection.

        - Paragraph 2.1.3.5 includes:

          Pipeline valves, expansion loops, and associated piping:

            - Pipe ground level transition coating condition
            - Pipe above grade coating condition
            - Structure (pipe supports) coating condition

- Paragraph *"Monitoring Atmospheric Corrosion"* includes:

  All components and piping in a pipeline system that are exposed to the atmosphere must be painted or coated to prevent atmospheric corrosion *according to GEN CP 39, "External Atmospheric Corrosion Control Program" and GEN CP 40, "Atmospheric Corrosion Inspections".* The painting or coating must be maintained to ensure effectiveness. The surfaces must be inspected every 3 calendar years, at intervals not exceeding 39 months for onshore pipelines, and once each calendar year at intervals not to exceed 15 months for offshore pipelines.

Documentation must include:

- Date of inspection
- Name of the person who performed the inspection
- Location of the pipe inspected
- Results of the inspection
- Date and type of corrective action taken

During these inspections special attention shall be given to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. If atmospheric corrosion is found during inspection, you must provide protection against the corrosion as required by 49 CFR 195.581.

- Must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere.
- Coating material must be suitable for the prevention of atmospheric corrosion

Documentation must include:

- Date of inspection
- Name of the person who performed the inspection
- Location of the pipe inspected
- Results of the inspection
- Date and type of corrective action taken

During inspections attention shall be given to pipe at soil-to-air interfaces, under thermal insulation, under disbanded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. If atmospheric corrosion is found during inspection, you must provide protection against the corrosion as required by 49 CFR 195.581.

- Must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere.

- Coating material must be suitable for the prevention of atmospheric corrosion.

Item 16 - Revisions made to Genesis LOM&E Manual, Section 2.19 External Corrosion, Section 2.20 Internal Corrosion, and Section 2.2 Pipeline Maps, Records, and Operational History:

Modifications in both Genesis LOM&E Manual Sections 2.19 and 2.20 now include a Records Retention paragraph:

Records Retention:

The company shall maintain a record of each analysis, check, demonstration, examination, investigation, review, survey and other tests in sufficient detail to demonstrate the adequacy and/or effectiveness of the company Corrosion Control Program pursuant to 49 CFR 192 and 195. These records must be retained for as long as the facility, pipeline, and the associated laterals remaining in service or as defined in Section 2.2 of this manual.

Genesis LOM&E Manual Section 2.2, records retention table under paragraph *"Activities"* includes:

* Documentation is required whenever this activity is performed.

DOCUMENTATION TABLE			
Activity to Document	**Frequency of Activity**	**Reference**	**Document Retention Time**
Abandoning Pipeline Facilities	*	OM&E, Section 2.23	Permanent record
Accident Analysis	*	OM&E, Section 4.5	2 Years
Breakout Tank Inspection	Once each calendar year not to exceed 15 months	OM&E, Section 2.11	2 Years
Construction Projects	*	OM&E, Section 2.1	Facility life
Discharge Pressure at Pump Stations	Continuous	OM&E, Section 2.18	3 Years
Drills • Qualified	• Quarterly	OPA Manual	• 3 Years

DOCUMENTATION TABLE			
Activity to Document	**Frequency of Activity**	**Reference**	**Document Retention Time**
Individual Notification • Tabletop • Equipment Deployment • Contractor Drill Verification	• Annually • Annually • Annually		• 3 Years • 3 Years • 3 Years
Emergency/Abnormal Conditions	*	OM&E, Sections 3.1-4.7	3 Years
External Corrosion • Bare Pipe Inspection • Exposed Pipe Inspections • Interference Bond, Reverse Current Switch and diode which could jeopardize protection to Company facilities • Other Interference Bonds, reverse current Switches, and diodes • Potential Surveys • Shorted Casings, Vapor monitoring • Repair of shorted casings • Rectifier	• Once every 5 years • * • Six times each calendar year not to exceed 2-1/2 month intervals • Once each calendar year not to exceed 15 months • Once each calendar year not to exceed 15 months • Twice each calendar year not to exceed 7-1/2 month intervals	• OM&E, Section 2.19 • OM&E, Section 2.19 • OM&E, Section 2.19 • OM&E, Section 2.19 • OM&E, Section 2.19 • OM&E, Section 2.19 • OM&E, Section 2.19	• As long as the pipeline remains in service • As long as the pipeline remains in service • As long as the pipeline remains in service • As long as the pipeline remains in service • As long as the pipeline remains in service • As long as the pipeline remains in service

DOCUMENTATION TABLE			
Activity to Document	**Frequency of Activity**	**Reference**	**Document Retention Time**
Inspections	• * • Six times each calendar year not to exceed 2-1/2 month intervals	• OM&E, Section 2.19	• As long as the pipeline remains in service • As long as the pipeline remains in service
Fire Fighting Equipment Inspection	See Safety Manual	OM&E, Section 4.7	See Safety Manual
Foreign Crossings	*	OM&E	Facility life
Gulf of Mexico	*	OM&E	2 Years - Reporting and Marking; Facility life – Reburial
Incident Reporting	*	OM&E, Section 4.6	Permanent record
Integrity Management Program Have a written integrity management program. Documents to support decisions and analyses. Document actions taken. See 49 CFR 195 Appendix C for specific guidelines.	Variable	Integrity Management Plan	Life of the facility
Internal Corrosion • Coupon (or other monitoring equipment) Inspection • Exposed Pipe Inspections	• Twice each calendar year not to exceed 7-1/2 months • *	• OM&E, Section 2.20 • OM&E, Section 2.20	• As long as the pipeline remains in service • As long as the pipeline remains in service
Line Locates	*	OM&E,	2 Years

DOCUMENTATION TABLE			
Activity to Document	**Frequency of Activity**	**Reference**	**Document Retention Time**
		Section 2.4	
Manual Review	Once each calendar year not to exceed 15 months	OM&E, Section 1.3	2 Years
MOP	Current	OM&E, Section 2.18	Facility life
Navigable Water Crossing Inspection	Once every 5 years	OM&E, Section 2.8	5 Years
Oil Spill Response Contractors – OPA Agreements	Current	OPA Manual	While under contract
Oil Spill Response Equipment Maintenance	Annually	OPA Manual	2 Years
Overpressure Safety Device Inspection	**Non-HVL** - Once each calendar year not to exceed 15 months HVL - Twice each calendar year not to exceed 7-1/2 months **HVL Breakout Tank Relief Valves** - Once every 5 years	OM&E, Section 2.10	2 Years or until next inspection, whichever is longer
Personnel Review	*	OM&E, Section 4.5	2 Years
Pipeline Movement	*	OM&E, Section 2.12	Facility life
P/L Integrity Testing-	*	OM&E, Section 2.17	Facility life

Public Education & Damage Prevention	• Yearly
	  • Govt/Contractor
	• Bi-Yearly
	  • Public
		OM&E, Section 2.4	2 Years or until next education effort is conducted, whichever is longer

Repair	*	OM&E, Section 2.14	Facility life (One year for non-pipeline components)

DOCUMENTATION TABLE			
Activity to Document	**Frequency of Activity**	**Reference**	**Document Retention Time**
Right-Of-Way Inspection	26 times each calendar year not to exceed 3-week intervals	OM&E, Section 2.7	2 Years
Safety-Related Conditions	*	OM&E, Section 3.1	2 Years
Training	See OM&E, Section 20	OM&E, Section 2.26	While employed
Valve Inspection	**Mainline Valves** - Twice each calendar year not to exceed 7-1/2 months **Other Valves** - Determined by each district	OM&E, Section 2.9	2 Years or until next inspection, whichever is longer
Welding	*	OM&E, Section 2.15	Facility life

Item 17 - Revisions made to Genesis LOM&E Manual, Section 2.10 Overpressure Protection Devices:

- Paragraph "*Procedures*" includes

Each pressure limiting device, relief valve, pressure regulator, and other types of pressure control equipment (pressure transmitters, switches, PCVs) shall be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year for crude oil and other non-HVL products and not exceeding seven and a half months, but at least twice each calendar year for HVL products, and each inspection and repair is documented on the appropriate form to determine that it is:

1. Functioning properly
2. In good mechanical/electrical condition
3. Adequate from the standpoint of capacity and reliability of operation for the service in which it is used.
4. Set to function at the correct pressure
5. Properly installed and protected from foreign materials or other conditions that might prevent proper operation.

Control and shutdown set points on pumping units shall be checked at intervals not exceeding 15 months, but at least once each calendar year for crude oil and other non-HVL products and not exceeding 7.5 months, but at least twice each calendar year for HVL products, to ensure the units are operating within design limits. If the check indicates a malfunction of the control devices, the unit will be shut down and remain so until control devices have been repaired or replaced, checked, calibrated and tested.

NOTE: In addition, the overpressure protection system must be inspected and tested, either actual or simulated, at the required overpressure protection set point. The Inspection originates from the pressure sensing device (i.e. pressure transmitter), and confirms intermediary equipment (i.e. PLC, SCADA system) will activate the proper response for pressure control.

In addition, test will be conducted on all relief valves on pressure breakout tanks not exceeding intervals of 5 years. The valve may have to be removed, totally torn down, inspected and tested.

Testing of relief valves means that pressure (nitrogen only) will be applied to the relief valve inlet to ascertain that the relief valve "pops" at the set pressure.
Any equipment found to be defective during the inspection, shall be repaired or replaced, as early as practicable. If a device is removed, to be repaired or tested, a pre-tested device shall be installed in its place to provide adequate protection.
Where feasible, these pressure-limiting devices shall be tested in place to determine that they function at the desired pressure setting. Any device used for overpressure protection of the pipelines will ensure the maximum relief set point will not allow the pipeline to exceed its MOP or exceed 110% of MOP even in surge or a failure mode.

OVERPRESSURE SAFTY DEVICE INSPECTION AND TESTING SCHEDULE	
Type	**When**
▪ Mainline relief valves ▪ Breakout tank/station piping relief valves ▪ High pressure shutdown devices ▪ Other devices, controls, or	<u>Non-HVL</u> Once per calendar year not to exceed 15 months between inspections <u>HVL</u> Twice per calendar year not to exceed 7.5 months between

alarms that protect the pipeline system from overpressure	inspections

Surge Analysis

There are two types of projects that may require surge analysis: pipeline modifications and hydrostatic tests.

Important Point:

The normal operating pressure on a pipeline must not exceed the maximum operating pressure (MOP). Surge pressures must not exceed 110% of mop. [195.406]

Typical pipeline modifications that could require surge analysis include, but are not limited to, the following:

- Adding new pump stations on an existing line section or adding new pumps at existing stations.
- Modifying existing pumps, e.g., more stages or larger stages
- Modifying station piping which might isolate protection devices, including relief systems
- Adding remote-controlled mainline gate valves on existing line sections
- Changing high pressure shutdown or low flow switch point settings
- Changing the operating philosophy or operating procedure of a line section, e.g., introducing a new "tightline" or "surge" operation without first analyzing it. Tightlining is receiving product from a facility or pipeline without providing any surge or storage capacity.
- Pumping new fluids with a higher specific gravity or bulk modulus than the fluids currently being pumped
- Adding equipment or pipe that has a design pressure lower than the mainline design pressure
- Changing the set point of mainline pressure relief valves, making the

pressure relief system inoperative or isolating the relief system from protecting the pipeline by changing the valve alignment.

On-Line Test of Relay Overpressure Protection Systems

1. Gather cause and effect documents or other source material for the overpressure protection system to be checked.
2. Identify all equipment that will be affected during the test. This will include PLC alarm points, pressure transmitters / switches, solenoids, and valves.
3. Review all devices to be tested with all affected operating areas. Ensure that equipment can be checked. Ensure Operations is aware of all affected equipment for each check.
4. Make note of any equipment that cannot be checked, reasons why, and the Supervisor who made decision.
5. Ensure equipment that is not checked is rescheduled to meet the minimum testing frequency required by company standards and federal regulations.
6. Obtain permit to check the overpressure protection Systems.
7. Isolate equipment from service, if applicable.
8. Prior to testing of each device, all affected operating areas will be notified.
9. Perform checks in accordance with manufacturer recommendations. All devices should function properly with the desired results. All alarm points, pressure transmitters / switches, solenoids, and valve should be verified at the PLC and in the field.
10. Record test findings.
11. Make repair as needed. A separate Work Order may be needed for repairs.
12. Return to step 7 until all devices have been tested and documentation is complete.
13. Inform all affected operating areas when complete, return equipment to

service.

14. Verify equipment is back in service
15. Close out permit.

NOTE: In addition, the overpressure protection system must be inspected and tested, either actual or simulated, at the required overpressure protection set point. The Inspection originates from the pressure sensing device (i.e. pressure transmitter), and confirms intermediary equipment (i.e. PLC, SCADA system) will activate the proper response for pressure control.

Inspection and testing of overfill protection systems will be conducted at intervals not exceeding 15 months, but at least once each calendar year or in the case of systems with HVL's are to be inspected at intervals not exceeding 7.5 months but at least twice each calendar year.

When the Company constructs or significantly modifies aboveground breakout tanks in accordance with API 2510 after October 2, 2000, an overfill protection system will be installed in accordance to API RP 2350. On occasion the Company may document in these procedures why the Company need not comply with any part of API RP 2350 for a particular tank, in regards to necessity for safety of the tank. However, after October 2, 2000, the Company will comply with the requirements of §195.428 regarding inspection and testing of overfill protection systems.

The Engineering Department shall be responsible for assigning over pressu safety device setting and pressure control limits in accordance with applicab codes. Local Field Office Supervision shall be responsible for implementing the instructions, performing the inspection and tests, and preparing the prop reports.

Local Area Supervision shall ensure that all testing devices (calibration equipmer are certified and/or calibrated in accordance with manufacturer recommendations not to exceed one year. Examples of testing devices may l dead weight testers, volt meters, test gauges, etc.

Documentation

All inspections of overpressure safety devices must be documented. Documentation must be kept for two years or until the next inspection is performed, whichever is longer. All documentation must include:

- Date of the inspection
- Name of the person who performed the inspection
- Location of the device
- Type of device
- Serial number or other designation of device
- Set point
- Results of the inspection
- Date and type of corrective action taken

Please see the attached copy of the amended sections in our OM&E Manual for your review. We appreciate the opportunity to work with the Pipeline and Hazardous Materials Safety Administration regarding the safe operation of our pipelines.

If you have any questions or comments, please feel free to contact me directly at 713-860-2542 or by e-mail at Jeff.Gifford@genlp.com.

Sincerely,

Jeffrey W. Gifford
Vice President, HSSE

Attachment