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| --- | --- |
| **Inspection Report** | **Post Inspection Memorandum** |
| **Inspector/Submit Date:** |       | **NC Required?****Inspection Tracking # :****NC Tracking # :** |       |
|       |
|  |       |
| **Corrosion Control Inspection** |
| **Name of Operator:** |       | **OPID #:** |      |
| **Name of Unit(s):** |       |  |  |
| **Records Location:** |       |
| **Unit Type & Commodity:** | Natural Gas |
| **Inspection Type:** |        | **Inspection Date(s):** |       |
| **PUC Representative(s):** |      | **Field Days:**       |  |
| **Qualified Corrosion Personnel:** | Supervisor | Technicians | Qualifications |  |  |
|       |       |       |
|       |       |       |
|  |       |       |       |  |  |
| **Summary:** |
|       |
| **Findings:** |
|       |

| **.605(b)** | **CORROSION CONTROL PROCEDURES** | **S** | **U** | **N/A** | **N/C** |
| --- | --- | --- | --- | --- | --- |
| .453 Are corrosion procedures established for: |  |
| **Design:** |  |
| 1. Is the native potential of a pipeline measured when installed?
 |     |     |     |     |
| 1. Is there criteria that specifies where electrical insulators are installed and where bonds are necessary?
 |     |     |     |     |
| 1. Does the procedure specify where test stations should be installed, in what manner, spacing, etc?
 |     |     |     |     |
| 1. Are there procedures for that specify how field applied coating are selected for tie in joints and above ground sections of pipe?
 |     |     |     |     |
| 1. Is sound engineering used to select ground bed locations to minimize interference with other structures?
 |     |     |     |     |
| 1. Are other pipeline companies who have facilities nearby contacted prior to installation of a cp system?
 |     |     |     |     |
| 1. Are the number, size, locations, and type of anodes determined by sound engineering?
 |     |     |     |     |
| 1. Are there criteria to monitor for excessive levels of CP to prevent coating disbondment and damage to high strength steels?
 |     |     |     |     |
| 1. Are current requirements for adequate CP based on soil resistivity, size of pipe, coating condition, interference currents, etc measured and calculated?
 |     |     |     |     |
| 1. Are calculations of anode life for impressed or sacrificial systems performed?
 |     |     |     |     |
| 1. Are drawings maintained to show the overall layout of the piping to be protected and the location of significant items of structure hardware, corrosion control test stations, electrical bonds, electrical isolation devices, and neighboring buried or submerged metallic structures?
 |     |     |     |     |
| **Operations & Maintenance** |  |  |  |  |
| 1. Are voltage drops accounted for when taking pipe to soil reads on galvanic anode systems and

impressed current systems? |      |     |     |     |
| 1. Is a high impedance digital voltmeter (10 mega ohms min.) or an analog meter (100,000 ohms min) used?
 |     |     |     |     |
| 1. Are polarities correctly read and interpreted when taking P/S measurements?

Is the pipe always more negative than the reference electrode? |     |     |     |     |
| 1. When only “on” P/S reads are taken, does the operator verify the following significant environmental, structural, or cathodic protection system parameter changes have not occurred to negate taking instant “off” readings:
	1. Replacement or addition of piping;
	2. Addition, relocation, or depletion of ground beds, anodes, or rectifiers;
	3. Failure of electrical isolating devices;
	4. Effectiveness of coatings; and
	5. Influence of foreign structures.
 |     |     |     |     |
| 1. Do procedures list the following causes of measurement error and actions to take to minimize?
	1. Pipe test lead deteriation or mixed potential
	2. Reference electrode contamination and placement relative to pipeline
	3. Reference electrode placement relative to anode gradient
	4. Possible temperature effects on reference cell
	5. Instrument calibration
	6. Voltage spiking during interruption
	7. AC interference from power lines or rail lines
	8. Dry soil, frozen soil, concrete, asphalt
 |     |     |     |     |
|  | 1. Are voltage drops considered?
	1. For Closed interval surveys, is the voltage drop and the direction of the current considered when the reference electrode is not near the pipe connection and significant current is conducted by the pipe?
	2. When P/S reads are measured with cathodic protection current applied, is the IR drop in the electrolyte between the reference electrode and the metal/electrolyte interface considered?
	3. Are voltage drops other than those across the structure-to-electrolyte boundary considered such as:
		1. Measuring or calculating the voltage drop(s);
		2. Reviewing the historical performance of the cathodic protection system;
		3. Evaluating the physical and electrical characteristics of the pipe and its environment; and
		4. Determining whether there is physical evidence of corrosion.
 |     |     |     |     |
| 1. Is the significance of voltage drops assessed?
 |     |     |     |     |
| 1. Are historical levels of cathodic protection compared with physical evidence (leaks, soil corrosiveness, buried pipeline reports) from the pipeline to determine whether corrosion has occurred?
 |     |     |     |     |
| 1. If 100 mV polarization criteria is used, is the depolarization measured from the IR free reading?
 |     |     |     |     |
|  |     |     |     |     |
| 1. Are the most difficult places to cathodically protect known on the system? If not, has a CIS been considered if practical?
 |     |     |     |     |
| 1. Are corrosion growth rates and the extent of corrosion measured for bare unprotected steel?
 |     |     |     |     |
|  |     |     |     |     |
| 1. Are initial current requirements of a system compared with later current requirements to assess condition of the coating?
 |     |     |     |     |
| 1. If leak history used as the sole method of determining cp effectiveness, has the company demonstrated why an electrical survey is impractical to use?
 |     |     |     |     |
|  |     |     |     |     |
| 1. Are all impressed current protective facilities inspected annually and may include a check for electrical malfunctions, safety ground connections, meter accuracy, efficiency, and circuit resistance? (a loss of efficiency or increase in resistance will indicate anode depletion or other issues)
 |     |     |     |     |
| **Installation** |      |     |     |     |
| 1. Is all work performed to construction specifications?
2. Is the installation supervised by qualified corrosion personnel?
3. Are lead wires inspected for damage and function once attached to pipe?
4. For impressed systems, before the power source is energized, is verification that the negative cable is connected to the structure to be protected and that the positive cable is connected to the anodes performed?
5. After the DC power source has been energized, are suitable measurements made to verify function.
6. Are precautions taken to minimize damage to anode cable by using proper backfill and leaving slack in the cable to avoid strain?
7. Are there procedures to install and bond test station lead wires to pipe?
 |      |     |     |     |
| .455 (a) For pipelines installed **after July 31, 1971**, buried segments must be externally coated and &(b) cathodically protected with **one year** after construction (see exceptions in code)  |      |     |     |     |
| .457 (a) All effectively coated steel transmission pipelines installed prior to **August 1, 1971**, must be cathodically protected |      |     |     |     |
|  (b) If installed **before August 1, 1971**, cathodic protection must be provided in areas of active  corrosion for: bare or ineffectively coated transmission lines, and bare or coated c/s, regulator station, and meter station piping, and bare or coated distribution lines. |      |     |     |     |
| .459 Examination of buried pipeline when exposed: if corrosion is found, further investigation is required |      |     |     |     |
| .461 Procedures must address the protective coating requirements of the regulations.  External coating on the steel pipe must meet the requirements of this part. |      |     |     |     |
| .463 Cathodic protection level according to **Appendix D** criteria |      |     |     |     |
| .465 (a) Pipe-to-soil monitoring (**1 per yr/15 months**) |      |     |     |     |
|  (b) Rectifier monitoring (**6 per yr/2½ months**) |      |     |     |     |
|  (c) Interference bond monitoring (**6 per yr/2½ months**) |      |     |     |     |
|  (d) Prompt remedial action to correct any deficiencies indicated by the monitoring |      |     |     |     |
|  (e) Electrical surveys on bare/unprotected lines, cathodically protect active corrosion areas (**1 per 3 years/39 months**) |      |     |     |     |
| .467 Electrical isolation (**include casings**) |      |     |     |     |
| .469 Sufficient test stations to determine CP adequacy using sound engineering judgment for placement of test stations? (arbitrary distances or convenience to roadways IS NOT sound engineering judgment) |      |     |     |     |
| .471 Test lead maintenance |      |     |     |     |
| .473 Interference currents |      |     |     |     |
| .475 (a) Proper procedures for transporting corrosive gas? |      |     |     |     |
|  (b) Removed pipe must be inspected for internal corrosion. If found, the adjacent pipe must be inspected to determine extent. Certain pipe must be replaced. Steps must be taken to minimize internal corrosion. |      |     |     |     |
| .477 Internal corrosion control coupon (or other suit. means) monitoring (**2 per yr/7½ months)** |     |     |      |     |
| .479 (a) Each exposed pipe must be cleaned and coated (see exceptions under **.479(c)**) |      |     |     |     |
|  Offshore splash zones and soil-to-air interfaces must be coated |      |     |     |     |
|  (b) Coating material must be suitable |      |     |     |     |
|  (c) Coating is not required where operator has proven that corrosion will: |  |
|  (1) Only be a light surface oxide, or |      |     |     |     |
|  (2) Not affect safe operation before next scheduled inspection |      |     |     |     |
| .481 (a) Atmospheric corrosion control monitoring (**1 per 3 yrs/39 months**) |     |     |     |     |
|  (b) Special attention required at soil/air interfaces, thermal insulation, under disbonded coating, pipe supports, splash zones, deck penetrations, spans over water |      |     |     |     |
|  (c) Protection must be provided if atmospheric corrosion is found (**per §192.479**) |      |     |     |     |
| .483 Replacement and repaired pipe must be coated and cathodically protected (see code for exceptions) |      |     |     |     |
| .485 (a) Transmission: Procedures to replace pipe or reduce the **MAOP** if general corrosion has reduced the wall thickness? |     |     |     |     |
|  (b) Transmission: Procedures to replace/repair pipe or reduce **MAOP** if localized corrosion has reduced wall thickness (unless reliable engineering repair method exists)? |      |     |     |     |
|  (c) Transmission: Procedures to use **Rstreng** or **B-31G** to determine remaining wall strength? |      |     |     |     |
| .487 Remedial measures (distribution lines other than cast iron or ductile iron) |      |     |     |     |
| .489 Remedial measures (cast iron and ductile iron pipelines) |      |     |     |     |
| .491 Corrosion control maps and record retention (**pipeline service life or 5 yrs**) |      |     |     |     |

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| **Comments:** *(If any of the above are marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note.)* |
|       |

| **CORROSION CONTROL PERFORMANCE and RECORDS**  | **S** | **U** | **N/A** | **N/C** |
| --- | --- | --- | --- | --- |
| .453 | CP procedures (system design, installation, operation, and maintenance) must be carried out by qualified personnel |     |     |     |     |
| .491 | .491(a) Maps or Records |     |     |     |     |
| .491 | .459 Examination of Buried Pipe when Exposed |     |     |     |     |
| .491 | .465(a) Annual Pipe-to-soil Monitoring (**1 per yr/15 months**) or short sections (**10 % per year, all in 10 years**) |     |     |     |     |
| .491 | .465(b) Rectifier Monitoring (**6 per yr/2½ months**) |     |     |     |     |
| .491 | .465(c) Interference Bond Monitoring – Critical (**6 per yr/2½ months**) |     |     |     |     |
| .491 | .465(c) Interference Bond Monitoring – Non-critical (**1 per yr/15 months**) |     |     |     |     |
| .491 | .465(d) Prompt Remedial Actions |     |     |     |     |
| .491 | .465(e) Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) |     |     |     |     |
| .491 | .467 Electrical Isolation (**Including Casings**) |     |     |     |     |
| .491 | .469 Test Stations – Sufficient Number |     |     |     |     |
| .491 | .471 Test Leads |     |     |     |     |
| .491 | .473 Interference Currents |     |     |     |     |
| .491 | .475(a) Internal Corrosion; Corrosive Gas Investigation |     |     |     |     |
| .491 | .475(b) Internal Corrosion; Internal Surface Inspection; Pipe Replacement |     |     |     |     |
| .491 | .476 (d) Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems |     |     |     |     |
| .491 | .477 Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**) |     |     |     |     |
| .491 | .481 Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore;** **1 per yr/15 months offshore**) |     |     |     |     |
| .491 | .483/.485 Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions |     |     |     |     |

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| **Comments:** *(If any of the above are marked U, N/A, or N/C, please indicate why, either in this box or in a referenced note.)* |
|       |

**Attach pictures if needed and OQ Protocol 9 to inspection.**

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| **Click on icon to insert picture and resize to fit box horizontally** |

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| NOTES:      |  |
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