INDIANA UTILITY REGULATORY COMMISSION

James Skomp

Operations Manager

Everything Corrosion

Code Sections

- 192.479 Atmospheric Corrosion Control
- 192.481 Atmospheric Corrosion Control
- 192.467 External Corrosion Control: Electrical Isolation
- 192.475 Internal Corrosion Control: General
- 192.461(f) External Corrosion control: Protective Coating

192.479 Atmospheric Corrosion Control

Protective Coatings

- (a) Each *operator* must clean and coat each *pipeline* or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
- (b) Coating material must be suitable for the prevention of atmospheric corrosion.
- (c) Except portions of pipelines in *offshore* splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will-

  (1) Only be a light surface oxide; or

  (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

-Surface Preparation
-Coating Materials
-Application Procedures

192.481 Atmospheric Corrosion Control: Monitoring

(a) Each *operator* must inspect and evaluate each *pipeline* or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

(b) (b) During inspections the operator must give particular attention 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.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec. 192.479.

(d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore *Service Line*	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) *Offshore*	At least once each calendar year, but with intervals not exceeding 15 months.

Records of actions taken for Atmospheric corrosion and who performed the task.

192.481 Atmospheric Corrosion Control: Monitoring

Inspection may require ladders, scaffolds, hoists, or other suitable means of permitting inspector access to the structure being inspected. In addition to the locations listed in §192.481(b), attention should be given to locations such as clamps, rest plates, and sleeved openings.

192.481(b) During inspections the operator must give particular attention 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.

192.481 Atmospheric Corrosion Control: Monitoring

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192.467 Exeternal Corrosion Control: Electrical Isolation

(a) Each buried or submerged *pipeline* must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

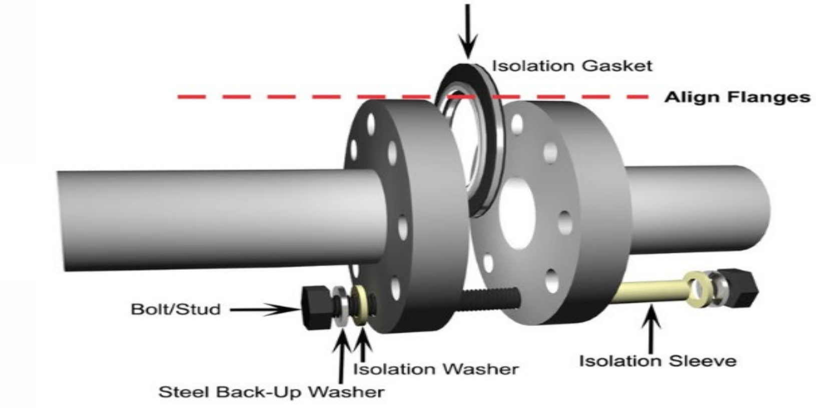
(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

192.467(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

-OQ for testing

-Procedures for testing

-where to test



PHMSA Enforcement Cases 192.467

Cases

520100016W – casing and flanges-warning letter

CPF 5-2010-0016W

Dear Mr. Mattson:

On July 27-29, 2010, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected BP Exploration Alaska's (BPXA) Badami Natural Gas Transmission Pipeline in Prudhoe Bay, Alaska.

As a result of the inspection, it appears that BPXA has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1.§192.467 External corrosion control: Electrical isolation. (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

The 2006-2009 Cathodic Protection Surveys did not check electrical isolation at the insulated flanges or all of the cased crossings. The CP survey must address the condition of insulation flanges and casings.

The probable violation was based on 2006-2009 Cathodic Protection Survey report and discussion with BPXA personnel.

PHMSA Enforcement Cases 192.467

Cases

420131018

CPF 4-2013-1018

Dear Mr. Kirsch:

On multiple dates in February and March, 2013, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code inspected portions of Centerpoint Energy Gas Transmission Co (CEGT) pipeline system located in Arkansas, Louisiana, and Oklahoma. PHMSA understands that CEGT is now known as Enable Gas Transmission, LLC.

As a result of the inspections, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. §192.467 External corrosion control: Electrical isolation.
   (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
   CEGT failed to conduct electrical tests on the foreign pipeline side at custody transfer points to assure adequate electrical isolation.

   According to the CEGT Corrosion Control Program, Procedure PS-03-02-232 Installation of Insulating Devices, section 2.2 Locations states,

   > "Typical locations where electrical insulating devices may be installed include the following:
   > Point at which facilities change ownership, such as meter stations and well heads. "

NACE SP0286-2007 (formerly RP0286)

AMPP

- Standard Practice
- Electrical Isolation of Cathodically Protected Pipelines

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

Electric Companies are reconductoring:

-this allows for more current

-no notification

-original mitigation insufficient with new current levels

192.475 Internal Corrosion Control: General

Verifying Pipeline Quality Gas

(a) Corrosive *gas* may not be transported by *pipeline*, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found-

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion:

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192,489; and,

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 standard cubic feet (5.8 milligrams/m3) at standard conditions (4 parts per million) may not be stored in pipe-type or *bottle*-type holders.

- Procedure for verifying
- Acceptable levels
- Records from Supplier
- RNG driven

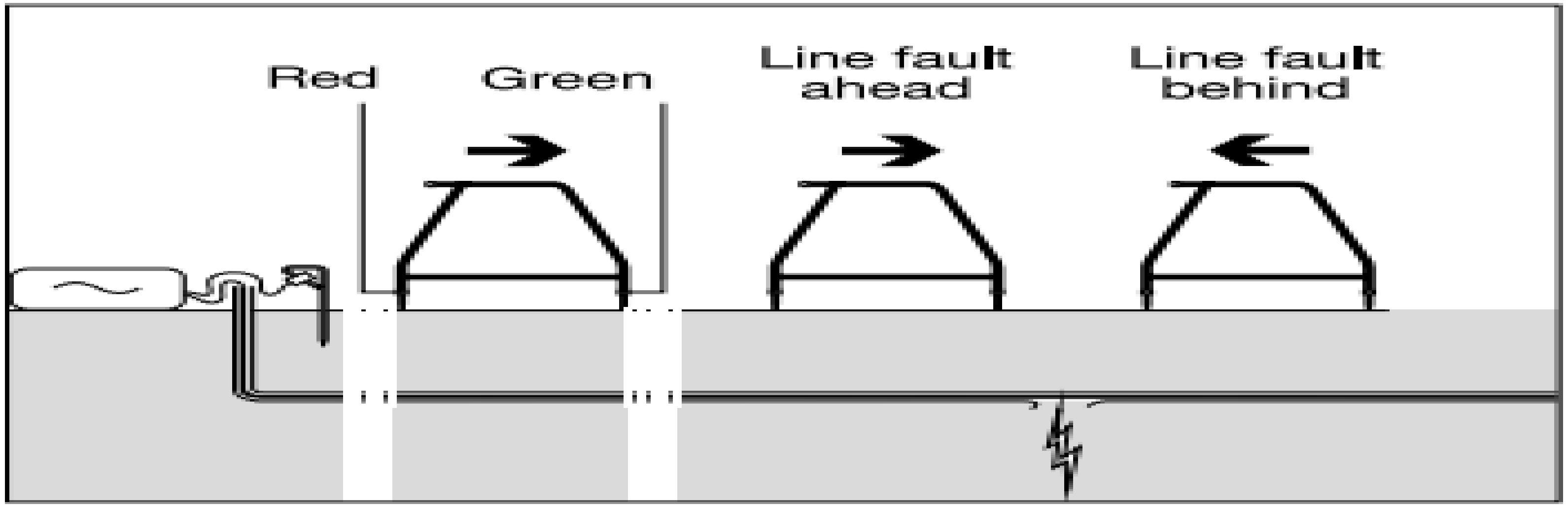
192.461 External Corrosion Control: Protective Coating

(f) Promptly after the backfill of an onshore *steel* transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the *operator* must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

Records needed: OQ of techs Date of backfill Date of survey Calibration of instruments Results of survey Actions taken	

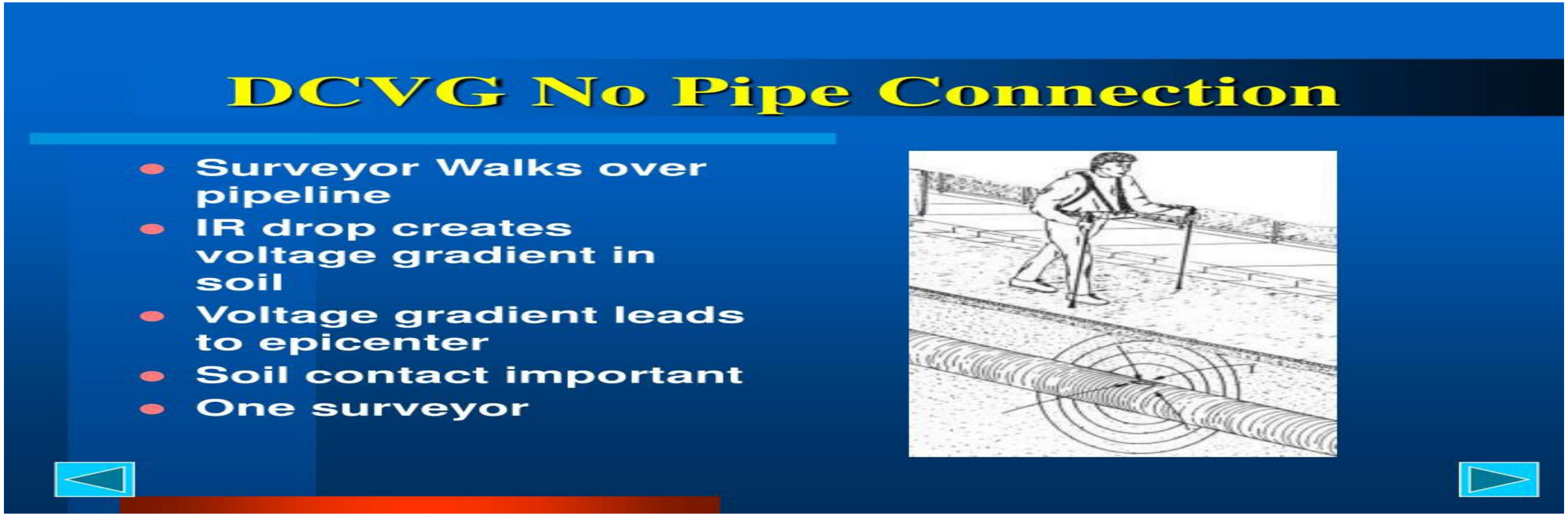
Alternating Current Voltage Gradient ACVG

ACVG is a survey technique used to evaluate the condition of pipeline coatings and locate defects, often referred to as "holidays." These defects can lead to corrosion and potential failures in the pipeline system. The ACVG method involves applying an alternating current to the pipeline, which creates a voltage gradient that can be measured to identify areas of concern.

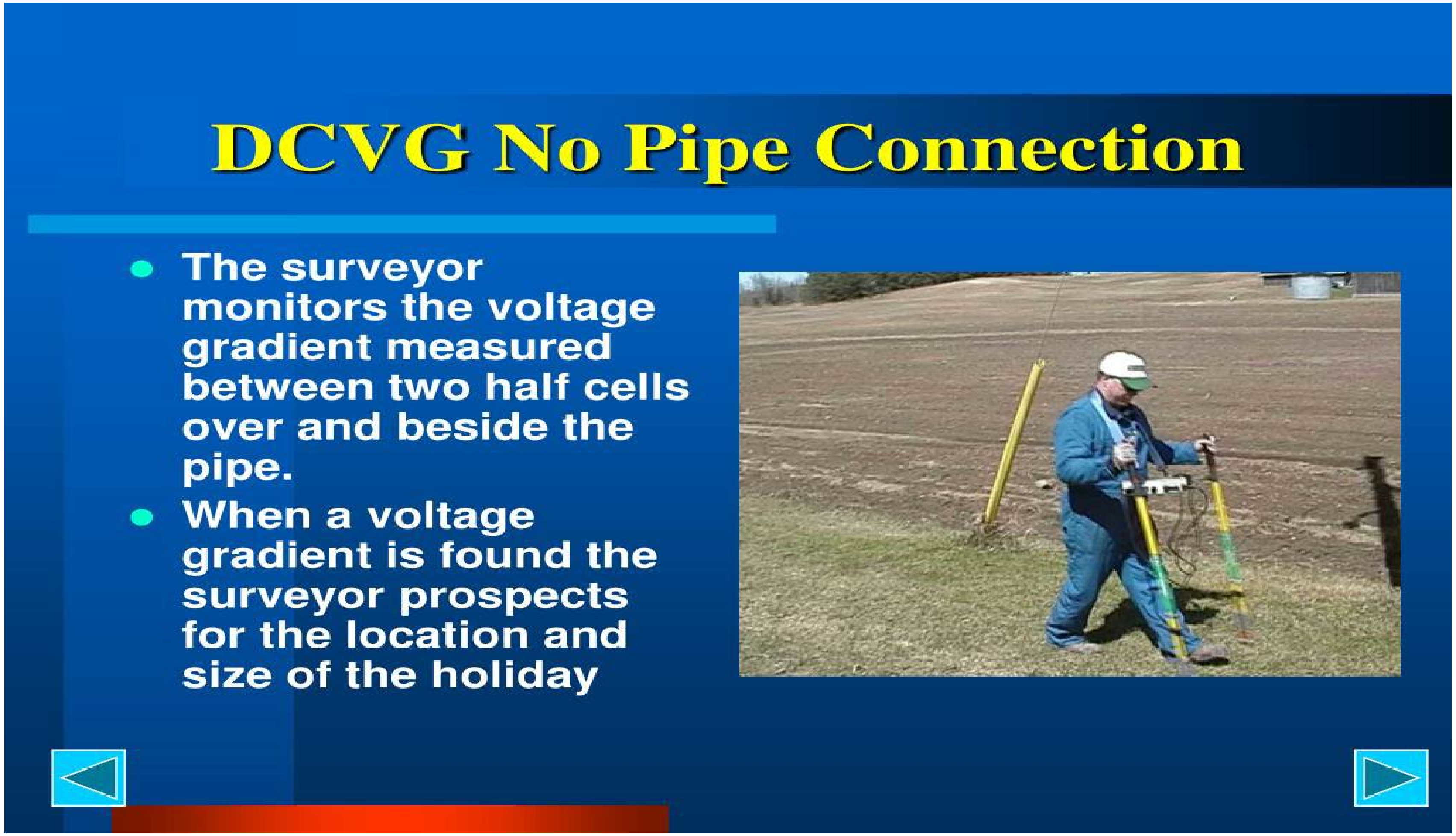


Direct Current Voltage Gradient DCVG

DCVG (Direct Current Voltage Gradient) testing is a survey technique used to locate coating defects and assess the effectiveness of cathodic protection on buried pipelines.



DCVG


DCVG No Pipe Connection
The surveyor monitors the voltage gradient measured between two half cells over and beside the pipe.
When a voltage gradient is found the surveyor prospects for the location and size of the holiday

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QUESTIONS

INDIANA
CORROSION SOCIETY

THANK YOU

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