Jeffrey L. Barger
Vice President
Pipeline Operations

Dominion Transmission, Inc.
445 West Main Street, Clarksburg, WV 26301-2450

Mailing Address: P.O. Box 2450
Clarksburg, WV 26302-2450

Dominion

June 8, 2009

Mr. Byron Coy Jr.
Director, Eastern Region
Pipeline and Hazardous Materials Safety Administration
Mountain View Office Park
820 Bear Tavern Road, Suite 306
West Trenton, NJ 08628

RE: CPF 1-2009-1003M

Dear Mr. Coy:

This letter is the formal response by Dominion Transmission, Inc. (DTI) to the Notice of Amendment dated May 8, 2009 (received by DTI on May 14, 2009), regarding the findings of the Pilot Inspection Integration performed in 2008. The following pages contain the thirty six (36) items, and DTI's response to each.

DTI has addressed a number of these concerns; however there are others that will require additional consideration and procedural development. For those items, DTI will provide quarterly progress reports to PHMSA, Eastern Region.

If you have any questions, or should require additional information, please do not hesitate to contact Shawn Miller at (304) 627-3404.

Respectfully,

1. § 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

DTI procedures do not designate responsibility for inspection or require that damage to pipe and components be documented and controlled

DTI Response:

DTI is revising its Inspector's Daily Report to include an entry summarizing the completed inspection of pipe and other pipeline components each day during construction. This form will also be used to note any damage observed, and actions taken in response.

2. § 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

DTI construction specifications have been established to define pipe field bending requirements but the procedures have not been established that would provide direction, acceptance criteria, and documentation requirements to be used by craftsmen and / or inspectors in the field.

DTI Response:

DTI's Inspector's Daily Report is being revised to include a log of the bends inspected each day during construction. The report will indicate each bend's compliance with the requirements of DTI's Design and Construction (D&C) Manual, Section 8.7.5. The D&C Manual is also being revised to require that an internal bending mandrel be utilized on all pipe 16" inches or greater in diameter.

3. **§ 192.319 Installation of pipe in a ditch.**

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

DTI construction procedures do not ensure that methods are used to prevent the overstressing of pipe when it is lowered into the ditch.

DTI Response:

Per section 8.6.5 of DTI's D&C Manual:

8.6.5 Ditch Bottom [§192.319]

Before the pipe is measured for bending, the bottom of the ditch shall be graded and completed in a manner that will provide uniform support for the pipeline after it is lowered into the ditch. The ditch shall contain sufficient loose earth or earth-filled sacks, free of rocks, to form a protective bed or pad for the support and protection of the pipeline.

DTI believes that the D&C manual language adequately addresses the requirements of §192.319, in regard to proper support of the installed pipe.

4 **§ 192.325 Underground clearance**

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

DTI's Design and Construction Manual should specify acceptable materials for use as an insulator between the pipeline and underground structures in close proximity.

DTI Response:

DTI is revising its D&C Manual to state that any approved "Rock Shield" (per the Corrosion Manual, Section 10) may be used as an insulator between the pipeline and underground structures in close proximity.

5. **§ 192.243 Nondestructive testing.**

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures

DTI does not have a process for ensuring that NDT procedures are qualified to API 1104 section 9 and that they are conducted by a trained and qualified person.

DTI Response:

This item contains two separate concerns:

1) **DTI does not have a process to ensure that NDT procedures are qualified to API 1104 Section 9.**

   DTI is revising its procedures to include a periodic review (by its designated Subject Matter Expert (SME)) of the NDT procedures used by its contractors, to ensure they are qualified to the most recently incorporated edition of API 1104 Section 9.

2) **DTI does not have a process to ensure that the NDT procedures are performed by qualified personnel.**

   DTI does indeed have procedures in place to ensure that all NDT personnel are qualified to perform the pertinent procedures:

   Per SOP 400/03 – Welding; Inspection and Test of Welds:

D. Nondestructive testing of welds shall be performed in accordance with written procedures and by persons trained and qualified in the established procedures and with equipment employed in the examination process.

And,

F. The Field Engineering Section - Engineering Services shall responsible for contracting NDE personnel and ensuring all NDE personnel are properly qualified. The operating location shall be responsible for scheduling nondestructive testing personnel for specific projects.

In addition, DTI is creating an NDT Personnel Inspection Form. This form will be utilized by the Project Supervisor during construction to ensure NDT personnel are qualified and have the appropriate equipment to perform the qualified NDT procedures.

6. **§ 192.243 Nondestructive testing.**

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).

DTI procedures have not been established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).

DTI Response:

DTI incorporates API 1104 Section 9 into its procedures to define the acceptability of a weld during nondestructive testing. Per SOP 400/03 – Welding; Inspection and Test of Welds:

E. The acceptability of a weld that is nondestructively tested or visually inspected shall be determined according to standards in Section 9 of API Standard 1104. Any weld that does not comply with the acceptance standards set forth in Section 9 shall be repaired or removed from the line.

7. **§ 192.243 Nondestructive testing.**

(d) When nondestructive testing is required under §192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

DTI Standard Operating Procedures (SOP) do not specify that all field butt welds that are nondestructively tested must have their entire circumference tested as required by §192.243(d).

DTI Response:

See DTI Response to Item #8

8. § 192.243 Nondestructive testing.

e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under §192.241(b).

DTI procedures do not require that a sample of each welder's work for each day be nondestructively tested, when nondestructive testing is required under §192.241(b)

DTI Response:

DTI is revising SOP 400/03 – Welding; Inspection and Test of Welds as follows:

B. Piping systems designed to operate at a pressure that produces a hoop stress 20% or more of SMYS shall have the welds nondestructively inspected over the entire circumference of the weld as per the following:

1. Ninety percent (90%) of each day's field butt welds, selected at random by the Company, in a Class 1 & 2 Area shall be nondestructively tested.

2. One hundred percent (100%) of all welds made in a Class 3 or Class 4 location, tie-in welds, and welds made within railroads or public highway rights-of-way including tunnels, bridges and overhead road crossings must be nondestructively tested.

3. One hundred percent (100%) of all welds made at major crossings of navigable rivers must be nondestructively tested unless impracticable, but in no case less than 90%.

When testing is required for any of the three situations, a sample of each welder's work for each day must be nondestructively tested.

9. **§ 192.55 Steel pipe.**

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

DTI Design and Construction (D&C) Manual section 2.2 inappropriately refers to 192 Appendix A for the referenced pipe specifications rather than 192 Appendix B.

DTI Response:

DTI has revised its D&C Manual to reference the appropriate Appendix.

10. **§ 192.159 Flexibility.**

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

DTI does not include parameters in the design criteria for when thermal expansion must be considered and evaluated by DTI engineering.

DTI Response:

DTI is revising section 4.3 of its D&C Manual to include a description of the parameters and situations in which thermal expansion must be considered and evaluated.

11. § 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

DTI's D&C Manual does not address the need to consider pulsation studies to ensure that pipeline and associated equipment have sufficient anchors and supports to prevent or dampen out excessive vibration. The D&C Manual does not provide a link or reference to standard drawings for support and anchor design.

DTI Response:

DTI is creating a new section in its D&C Manual to provide guidance as to when a pulsation study is required.

The D&C Manual will be revised to include a statement that refers the project manager to Drafting and Records for the most current revision of any standard support or anchor design.

12. § 192.179 Transmission line valves.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

DTI's D&C Manual does not provide guidance on the type and level of protection to be used to prevent block valve tampering or damage based on site specific circumstances.

DTI Response:

DTI is revising section 4.7.3 of its D&C Manual to include the following paragraph:

Specifically, design consideration should be given for the inclusion and provision of appropriate protection from tampering and damage based on environmental factors. Environmental factors to consider include but are not limited to surrounding area population, history of vandalism or tampering occurrences, and exposure to weather.

In addition, DTI is revising section 4.7.3 to include a list of typical situations that warrant specific protective devices.

13. § 192.179 Transmission line valves.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

DTI's D&C Manual Table 4.6 is limited to pipelines 30 inches and smaller although larger pipe sizes are used in the DTI pipeline system. The D&C Manual needs to address all sizes used in DTI construction to insure that blowdown valves installed have enough capacity to allow the transmission line to be blown down as rapidly as practical.

DTI Response:

DTI is revising its D&C Manual, Table 4.6, to include the required dimensions of blowdown valves on 36" pipelines. Additionally, the following statement will be included:

For nominal pipe diameter blow off sizes not listed in the above table, contact Pipeline Engineering Services for calculation and determination assistance.

14. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

The DTI emergency plan does not include coordination provisions when larger incident command centers are established that may include other organizations such as the fire department or other government agencies that may be on location following a significant emergency.

DTI Response:

DTI's Combined Emergency Plan prescribes the method by which a command center is created in the event of an emergency:

The **Emergency Command Center:** is established on site by the ranking employee who is sent to assess the situation. From this center, contact should be established with the Gas Control Dispatcher to relay information. This center may initially be the employee's radio vehicle. If needed, this center may later be relocated or become a fixed structure near the site of the emergency.

The decision of where to locate an Emergency Command Center is dependent on the location of the incident. For this reason, DTI does not pre-designate one central location for the Command Center.

15. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

DTI emergency procedures do not specify the site-specific equipment (also contractor equipment) that must be available and operable to support emergency response. DTI procedures do not address checks of emergency equipment to ensure operability for emergency response.

DTI Response:

DTI includes a list of qualified contractors in each of its Site-Specific Emergency Plans. DTI relies upon these lists as a source of the necessary tools, personnel, and equipment to aid its response to an emergency situation. As DTI does not maintain specific equipment for emergency response, there is no reliable way to account for its exact location in the event of an emergency. By stating that equipment is located at a specific location, DTI would be in violation of its own Emergency Plan in the event that such equipment was deployed elsewhere at the time of an accident.

16. **§ 192.615 Emergency plans.**

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

DTI site-specific emergency plans do not include all necessary direct phone numbers to contact local emergency responders. For Fire Departments, Emergency Medical Services and Law Enforcement agencies, only an outside line "911" phone number is listed under "Phone Numbers".

DTI Response:

DTI will communicate to Operations personnel the importance of listing the contact information for individual agencies within the Site-Specific Emergency Plans. However, it should be noted that much of DTI's operating area is covered by volunteer fire departments, which are not typically staffed around the clock. For this reason, DTI relies on "911" as its primary emergency contact number.

17. **§ 192.615 Emergency plans.**

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

The DTI emergency preparedness liaison process does not ensure that the responsibility and resources of each government organization that may respond to a gas pipeline emergency is learned.

DTI Response:

Each Liaison Meeting attendee is asked to complete the "Emergency Response Preparedness Report"(see Appendix D) included in the meeting literature. These forms are collected by the meeting contractor, then provided to DTI on a CD included in the meeting documentation. Also, an analysis is performed to determine which attendees did not complete a form. Forms are then mailed to those attendees, and requested to fax the completed form to the contractor. While DTI is collecting this information, it recognizes the need to improve the process by which the information is communicated to its Operations personnel. DTI is currently evaluating the process and identifying improvements.

18. § 192.615 Emergency plans

(b) Each operator shall:

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

DTI emergency procedures do not define the process for review of employee actions to determine if emergency procedures were followed and are effective.

<u>DTI Response:</u>

To better meet the requirements of §192.615(b)(3), DTI plans to utilize the new Procedural Observations process outlined in the response to Item #25 of this Notice.

19. § 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

DTI has not defined the process for analyzing accidents and failures of equipment, and how to communicate lessons learned. As an example, the pipeline failure investigation report for the 12/1/2007 accident on pipeline TL-453 does not document, or reference, the actions taken to identify, and prevent recurrence of, internal corrosion at pot drips on transmission lines.

<u>DTI Response:</u>

DTI has developed, and implemented a revised "Failure and Accident Investigation" form, which is linked to SOP 130/01 – Failure and Accident Investigations. A copy of the form is provided in Appendix A of this Response.

Additionally, DTI is revising SOP 130/01 – Failure and Accident Investigations, in order to *address the communication of "Lessons Learned" as follows:*

IV. RECORDS

A. Investigations of failures and accidents shall be recorded on the **"Pipeline Failure Investigation Report Form"**. The completion of each investigation will be entered, by Pipeline Integrity, into the Communications Tracking Database, along with a link to completed report. Records of investigations for transmission, storage and jurisdictional gathering pipeline facilities shall be retained for a minimum of five (5) years.

20. § 192.731 Compressor stations: Inspection and testing of relief devices.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

At the time of the inspection, DTI representatives stated they were not able to ensure that compressor station emergency shutdown systems (ESD) inspections do not repeatedly use the same ESD activation point as was used in previous year's testing Which ESD device is tested is apparently not tracked or recorded. While DTI procedures state that the emergency shutdown test activation point should be different from the previous successful test, there is no process defined to ensure that no activation point is repeated from the previous year.

DTI Response:

DTI is revising SOP 060/01 – Compressor Stations; Emergency Shutdown Systems. The following statement will be removed from the procedure:

H. The activation point should be different from the previous successful test.

21. § 192.736 Compressor stations: Gas detection.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

DTI compressor station inspection records do not specify the type of CGI sensor that is being inspected. Different CGI sensors have different maintenance requirement schedules. The type of sensor must be known to schedule the required quarterly or annual inspection.

DTI Response:

DTI is modifying the device inspections within its Inspection Monitoring System (IMS) to reflect *the type of sensor being inspected.*

22. § 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

DTI SOP 210/02 does not define what are the "Accepted and expected limits" for regulator shutoff.

DTI procedures do not define relief device set-points. DTI procedures do not address build-up pressure of the relief valve to achieve full open condition.

DTI procedures for relief device pressure calculations do not account for inlet and outlet piping restrictions which might affect proper pressure set-point.

<u>DTI response:</u>

"Accepted and expected limits"

DTI is adding the following language to SOP 210/02 – "Measurement and Regulation; Pressure Limiting, Regulating and Compressor Stations – Inspection and Tests":

> *Regulator set-point should be mechanically established at exact set-point as requested by IMS, Gas Control, Operations Supervision, etc. using a calibrated standard as verification. Plus or minus deviation from required set-point is not acceptable. Set-point should be adjusted during flowing conditions in order to accommodate for lock-up "droop" upon discontinuation of flow through the regulating device.*

"Set Points"

DTI specifies 0% build-up when soliciting quotes from relief valve vendors. Set-point as specified in device quote solicitation yields full volume flow with 0% build-up of pressure, by design. Capacity calculations are theoretical calculations based on published manufacturers' data as allowed per §192.743. DTI does not conduct experimental determinations in effort to determine relief device capacities.

"Inlet and Outlet Piping"

DTI recognizes the need for improvement in this regard. However, resolution of this issue will be a major undertaking, as it will require a configuration review of nearly 4,600 individual devices across DTI's system. DTI is evaluating how to proceed, and will update PHMSA as it *develops a plan to address this concern.*

23. § 192.745 Valve maintenance: Transmission lines.

(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

DTI procedures do not clearly define partial operation of valves during inspection for ensuring proper operation of the valves during an emergency.

DTI procedures do not define the terms good, fair, poor, or pitted are used on valve inspection documentation.

DTI Response:

Partial Operation:

DTI is revising SOP390/01- "Valve Inspection and Maintenance; Transmission, Storage, and Jurisdictional Gathering Pipelines" to include the following definition:

***"Partial Operation** of a valve occurs when the operator confirms visually that the position indicator has moved."*

Definition of Good, Fair, Poor, and Pitted:

In an effort to improve consistency, DTI is revising its valve inspection form to eliminate the field "Valve Condition" which includes the choices of Good, Fair, Poor, and Pitted.

24. § 192.745 Valve maintenance: Transmission lines.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

DTI has not established procedures to specify how proper lubrication of valves is to be conducted for valves found in need of remedial action.

DTI Response:

DTI's procedures do indeed require prompt remedial action when a valve is found to be inoperable. However DTI does not believe the requirements of §192.745 include detailed procedures for the maintenance of individual valves. Manufacturers' recommendations are relied upon for this type of maintenance.

25. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

The process for evaluating the effectiveness of DTI procedures is not described in the DTI SOPs

DTI Response:

DTI is revising its procedures to address this item. The IMS will be utilized periodically to track the evaluation of procedures during the observation of the pertinent tasks. A diagram of this new process is provided in Appendix B.

26. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

DTI procedures do not give descriptions of significant hazards that require system shutdown.

DTI procedures do not address the evaluation of system abnormal operating conditions to ensure that other pipeline facilities have not been damaged, or that other similar facilities will not experience the same abnormal operating condition.

DTI procedures do not specify whether root cause analysis, or other types of analyses should be used to determine the cause of abnormal operating conditions. Possible significant factors to consider in the analysis are not addressed.

DTI Response:

DTI is revising SOP 020/01 – Abnormal Operations; Abnormal Operating Conditions as follows:

B. Effectiveness of the Response to Abnormal Operations Procedures

1. ~~1.~~Abnormal Operations training and testing will be conducted annually for all applicable operating personnel. Results are maintained by the DTI Technical Training Department.

~~1.~~2.If the evaluation of the abnormal operating condition reports reveals a need to communicate preventive information, a monthly "AOC Tip" will be used to do so. When utilized, the tip will be a required element of the monthly Safety Meeting.

Additionally, DTI is revising its procedures to include the following language:

"Abnormal Operating Conditions (AOCs) are unexpected, unintentional, non-emergency events that cause a pipeline system's operating capacities or design limits to be exceeded. In some instances, these AOC's can be the early stages of a pipeline emergency although they seldom result in system shutdown. However, there are some instances where system shutdown may be required to ensure public safety and/or to minimize damage to equipment. Some AOC examples requiring system shutdown are included in the ten (10) examples below (see A through J) but may also include such issues as:

- *potentially over-pressuring a pipeline above its MAOP;*
- *a non-emergency gas leak located in a populated area or right-of-way of a public road or railroad that does not meet the monetary threshold of an incident;*
- *operation of an alarm or shutdown device on a compressor unit that detrimentally affects system operation;*
- *pressure control equipment operating outside of acceptable limits;*
- *personnel error that may have jeopardized the safe, on-going operation of the facility."*

27. § 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

DTI SOP 330 / 01 states that purging is not required when the volume of gas is so small that a potential hazard does not exist. However, the criteria defining a "small" amount of gas is not provided to determine when purging may not be necessary.

DTI SOP 330 / 01, Section VII.F states that end point samples "may" be taken with an accurately calibrated combustible gas indicator (CGI), natural gas detecting instrument, gravity measuring instrument, oxygen indicator, or other approved device to ensure the completeness of the purge.

One of these instruments "must" be used in order to establish that air / gas concentration meets the acceptance limits specified in SOP 330 / 01 Section VII.E.

DTI Response:

DTI is revising SOP 330/01 – Purging of Pipeline and Compression Facilities, to define situations when purging is and is not necessary:

C. Purging is not required when the volume of gas is so small that a potential hazard does not exist.

Examples of Facilities not requiring a Purge
Launchers/Receivers
Meter Tube inspections
Regulator inspections
Short segment of small-diameter M&R Piping.
Short segment of small-diameter Compressor Station piping.
Short segment of small-diameter Storage Gathering piping

Examples of when purging is required
Compressors on Engines removed from service
Gas Transmission Pipeline segments removed from service
Storage Gathering Pipelines segments removed from service
M&R Stations removed from service

Additionally, DTI has revised SOP 330/01 Sections IIV and IX to provide options in how the pipeline purge is deemed "complete":

~~E. Once the purging operation has started, it must continue uninterrupted until samples of the vent gases have firmly established the following end points:~~

~~**Pipelines Purged Out of Service**~~
~~MAX – 2% Natural Gas, MIN – 98% Air~~
~~**Pipelines Purged Into Service**~~
~~MIN – 95% Natural Gas, MAX – 5% Air~~

~~F.~~ E End point samples may be taken with an accurately calibrated combustible gas indicator (CGI) {**Pipelines Purged Out of Service**-MAX – 2% Natural Gas, MIN – 98% Air, **Pipelines Purged Into Service**-MIN – 95% Natural Gas, MAX – 5% Air}, , natural gas detecting instrument, gravity measuring instrument, oxygen indicator, or other approved device to ensure the completeness of the purge.

And;

IX. PLACING A TRANSMISSION LINE IN SERVICE

A. Prior to placing a transmission or storage pipeline in service, it should be properly purged by one of the following methods:

1. Pipeline Purging Computer Model: The Pipeline Tool Box software program is available to DTI personnel. Prior to purging the pipeline, calculations should be performed by an employee familiar with the Pipeline Tool Box program.

2. Inlet Control Method: An accurate pressure gauge should be installed on the upstream pressure tap, and the downstream blow off should be opened to the atmosphere An inlet pressure of 45 to 60 psig should be quickly established and maintained for a total time equal to two (2) minutes per mile of pipeline section. At the end of this period, the inlet gas flow should be shut off and the downstream blow off should be left open for an additional one-half (1/2) minute per mile.

EXAMPLE:
Twenty (20) Mile Section of 20" OD
Purge 20 miles x 2 min = 40 minutes
Coast 20 miles / 2 min = 10 minutes
Total Time = 50 minutes.

3. Double Pressure Method: With the downstream blow off open, gas should be introduced into the pipeline section at a reasonable rate until the pressure at the open blow off reached 20 psig at which time the gas inlet valve should be closed. The blow off should remain open until the pressure at this point falls to two (2) psig. This procedure should be repeated until the criteria in Section ~~7~~VII subpart ~~D~~E is met.

28. § 192.491 Corrosion control records.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

DTI corrosion control documentation procedures related to §192.481(b) do not provide sufficient detail necessary to ensure that the inspection process identifies and gives particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, and at specific locations within a DTI station or at other facility areas.

DTI Response:

DTI's inspection form for Atmospheric Corrosion requires the inspector to specifically examine all of the required areas noted in §192.481(b). The image below is a sample inspection form.

DOMT
Responsible Inspector: ALL

Inspection History Detail Listing
Atmospheric Corrosion Insp. - Trans

5

Storage Pool: ALL
Area: T&S Northeastern Area
Location: Sabinsville Storage Pool

Inspection: TATCO Atmospheric Corrosion Insp. - Trans

Contractor/Inspector

Detail Location	Survery Station From	Survery Station To	Due Month	Inspect Date	Inspected By
N-41-S / BURNSIDE - WELLHEAD INSP	000000 + 00	000000 + 00	May 2008	07/22/2008	[redacted]

Line Number
Line #1: NONE **Ext.:**
Line #2: **Ext.:**
Line #3: **Ext.:**

Latitude: .000000 .000000
Longitude: .000000 .000000
Responsible Inspector:

Environmental Corrosivity: Mild to Moderate Harsh
Coating Rating: (A) Perfect or less than 1% corrosion and/or defects

Other Concerns (Rate 1, 2, 3, or 4 according to the descriptions)

Soil-to-Air Interfaces	3	Under Thermal Insulation	4
Under Disbonded Coatings	4	At Pipe Supports/Piers	4
At Deck / Wall Penetrations	4	Spans Over Water	4

4 - not applicable to item being inspected
3 - situation exists but there are no coating/corrosion concerns
2 - situation exists and there are corrosion/coating concerns that should be addressed before the next inspection (3 years)
1 - condition exists and there are coating/corrosion concerns that need addressed within 15 months

Atmospheric Corrosion: 4 - No Visible Rust
CAPP reinspection form used? No **Last Updated By:** [redacted] **Last Updated On:** 07/22/2008

Follow Up	Remarks By	Remarks Date	Compliance Date	Contractor/Inspector
Inspection OK	[redacted]	07/22/2008	00/00/0000	

29. § 192.461 External corrosion control: Protective coating.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

DTI procedures are not adequate to ensure that pipe coating is not damaged when pulled through borings or horizontal directional drillings.

<u>DTI Response:</u>

DTI is revising its procedures to require an evaluation of the coating at the pipe end upon emerging from the bore.

30. § 192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

DTI Corrosion Control Procedure 070, SOP 06, uses the permissive terminology "should" or "may" for specifying external protective corrosion control requirements when the intent is that the requirements "shall" or "must" be met. Definitions and expectations for "should" and "shall" requirements are outlined in ASME B31.8S which is incorporated into portions of Part 192 by reference.

DTI Response:

DTI appropriately uses the term "shall" when specifying the need for external protective coating. The following is an excerpt from SOP 070/06 – Corrosion Control; Protective Coating:

II. EXTERNAL PROTECTIVE COATINGS

A. External protective coatings, whether conductive or insulating, applied for external corrosion control shall adhere to the following criteria:

1. External protective coatings shall:

a. Be applied on a properly prepared surface.

b. Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture.

c. Be sufficiently ductile to resist cracking.

d. Have sufficient strength to resist damage due to handling and soil stress.

e. Have properties compatible with any supplemental cathodic protection.

f. Have low-moisture absorption and high electrical resistance. (This requirement only applies to an electrically insulating-type coating.)

31. § 192.453 General.

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

DTI procedures and program documentation do not define the pipeline corrosion control qualifications for company and contractor personnel involved with carrying out the corrosion control procedures for the design, installation, operation, and maintenance of cathodic protection systems, and other pipeline corrosion control methods.

DTI Response:

DTI has developed a qualification requirement document for Company personnel. A copy of that document is provided in Appendix C of this Response. DTI is currently developing the same qualification requirements for Contractor personnel.

32. § 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

DTI SOP 070 / 03 Section V.A states that the cathodic protection requirements may be modified for temporary pipeline installations with an operating life not to exceed five (5) years beyond installation as long as prior approval is received from the Pipeline Integrity Section. However, it does not specify that the temporary condition must not be detrimental to public safety.

DTI Response:

DTI is revising SOP 070/03 – Corrosion Control; Cathodic Protection Requirements as follows:

V. TEMPORARY INSTALLATIONS

A. The cathodic protection requirements included in Part III., above, may be modified for temporary pipeline installations with an operating life not to exceed five (5) years beyond installation; provided that the situation is not detrimental to public safety. H~~h~~owever, prior approval must be received from the Pipeline Integrity Section.

33. § 192.463 External corrosion control: Cathodic protection.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

DTI SOP 070 / 07, Cathodic Protection Criteria, Section II.A states that the amount of cathodic protection applied shall be controlled to prevent damage to the protective coating or the pipe. However, procedures do not define criteria on how to control the amount of cathodic protection applied to prevent damage to the pipe coating.

DTI Response:

DTI recognizes the need to address this issue; however its complexity hinders the implementation of a simple solution. This is an area of concern for the entire pipeline industry, and one that DTI is working to address. DTI will revise its procedures accordingly when the appropriate solutions have been identified.

34. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

DTI procedures are inadequate to control internal corrosion. The procedures do not ensure that fluid samples from drips are consistently taken following the annual blowdown of transmission lines, and that those samples are analyzed for evidence of conditions conducive to internal corrosion.

DTI inspection history detail drip blowing forms do not indicate if fluids, other than just water, are removed from the pipelines. DTI procedures needs to address other fluids found in the drip blowing process.

DTI Response:

Sampling Issue:

While DTI does not dispute that annual sampling (and analysis) at each drip would greatly enhance its Internal Corrosion Program, requiring such would place an extreme burden on

Operations both financially and logistically (personnel, training, equipment, etc.). DTI is working to develop a plan by which this requirement can be gradually implemented, thus easing the burden on Operations. DTI will convey this plan to PHMSA upon development.

Drip Blowing Form:

DTI has modified its drip blowing inspection form to address the issue of fluids other than water being removed from the pipeline.

35. § 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

The DTI Pipeline Repair Manual allows for the use of the Clock Spring repair method for permanent repair of wall thickness loss due to internal corrosion as long as the internal corrosion is no longer active. DTI procedures do not specify when internal corrosion is no longer active, or define how to determine when internal corrosion is no longer active.

DTI Response:

DTI has revised its Pipeline Repair Manual. The use of a ClockSpring for the repair of an internal corrosion defect is no longer permitted.

36. § 192.471 External corrosion control: Test leads.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

DTI procedures for thermowelding of test leads do not require verification of pipe wall thickness to ensure the thermowelding process does not create a stress concentration on the pipe due to inadequate pipe wall thickness.

DTI Response:

DTI is revising its procedures to require an evaluation of the pipe (at the installation point) for visible corrosion. If corrosion is present, a remaining strength calculation will be required prior to the installation of the test leads.