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July 29, 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 1-2009-1006

Dear Mr. Coy:

This letter is the formal response by Dominion Transmission, Inc. (DTI) to the Notice of Probable Violation dated June 26, 2009 (received by DTI on July 2, 2009), regarding the findings of the Pilot Inspection Integration performed in 2008. The following pages contain the items of concern and DTI's response to each.

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

Respectfully,

Jeffrey L. Barger
Vice President, Pipeline Operations
Dominion Transmission, Inc.

1. § 192.481 Atmospheric corrosion control: Monitoring

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

<u>If the pipeline is located:</u>	**<u>Then the frequency of inspection is:</u>**
Onshore	**At least once every 3 calendar years, but with intervals not exceeding 39 months**
Offshore	**At least once each calendar year, but with intervals not exceeding 15 months**

Under § 192.481, DTI is required to inspect each portion of pipeline that is exposed to the atmosphere at least once every three calendar years for onshore pipe for evidence of atmospheric corrosion. DTI must perform these inspections at intervals not exceeding 39 months. However, DTI failed to inspect the run #1 back-up fuel gas regulator station near valve FGV-25 at the Oakford Compressor Station. The piping had surface rust and pits measuring up to 80 mils in depth on a 5"x 8" area on top of the run. Also, atmospheric corrosion was found on the dehydrator dry gas header outlet with pits measuring approximately 110 mils in depth at the ground to air transition. Although DTI performed an atmospheric corrosion inspection in 2007, it failed to identify these areas of atmospheric corrosion.

<u>DTI Response:</u>

It is apparent that the fuel gas piping in the vicinity of valve FGV-25 was overlooked during the 2007 Atmospheric Corrosion inspection. However, the corrosion at the soil-to-air interfaces on the Dehy wet and dry risers was identified in the KTA (corrosion evaluation contractor) report, and scheduled for remediation. This work was complete at the time of the PHMSA inspection; however the remediation did not comply with DTI's procedures. The below-ground coating did not extend above grade, and the above-ground coating did not extend over the below-ground coating. This resulted in bare pipe remaining at the soil-to-air interfaces, as noted in Item #1 of the NOPV. Both concerns noted in Item #1 were addressed in October 2008, and were remediated in compliance with DTI's Procedures.

Identification of the Dehy Riser Corrosion Issue (from KTA Report dated May 11, 2007):

1.15.35.61.241.1130	Piping - DDs Riser	Surface to Air Interfaces	C	NM	NR	150	Alkyd/Alkyd	Steel	Mill Scale	Surface to Air Interface	Average	Unknown				The 3 center surface to air interfaces do not appear to have a specialized surface to air interface coating. Heavy corrosion was observed on one.

2. **§ 192.605 Procedural manual for operations, maintenance, and emergencies**

(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least one each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(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.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.
(2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part.

DTI failed to follow its corrosion control maintenance requirements requiring drips to be blown at least annually. DTI's Standard Operating Procedures (SOP) Section 070/Corrosion Control, SOP 15/Internal Corrosion states that all drips should be blown at least once each calendar year. Maintenance records of the drips in the Oakford Fifth Sands and Murrysville Storage Pools show that a total of 103 and 330 drips, respectively, from 2003 to 2007 were not blown annually to remove fluids which can be corrosive to steel pipelines. Additionally, DTI has documented 69 drips which have not been blown because they cannot be accessed, cannot be blown and/or are not piped up. These 69 additional drips are in a DTI schedule to be corrected within 9 years.

<u>DTI Response:</u>

Item #2 of the Notice states that the Fifth Sand and Murrysville storage pools contain 103 and 330 drips respectively. In actuality, the drip total for Oakford Storage (Murrysville and Fifth Sand combined) is 331. In 2008, 63 of these were not operable, for the variety of reasons noted in Item #2. As of July 29, 2009, 42 of the 331 drips remain inoperable. 289 of the drips can, and have been blown in the past year. DTI estimates that the remaining 42 drips can be either removed or repaired by August 1, 2010.

3. **§ 192.709 Transmission lines: Record keeping.**

Each operator shall maintain the following records for transmission lines for the periods specified:

c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

DTI failed to provide records for the required last 5 years (2003-2007) to demonstrate that annual capacity calculations were performed for pressure relieving devices at five compressor stations (Harrison, Ellisburg, Stateline, Oakford and JB Tonkin) as required by §192.731 and §192.743. DTI failed to provide to the PHMSA inspection team, during headquarter and field inspections, compressor stations records showing the capacity review and calculations for their relief devices. Although DTI reviews the initial capacity calculations as permitted by §192.743(b) in order to meet the annual capacity determination requirements for relief devices, DTI is still required to demonstrate that the parameters have not changed to avoid subsequent calculations. DTI could not provide records to demonstrate this required review of the parameters was performed.

DTI Response:

Prior to these being recorded electronically in DTI's Inspection Monitoring System (IMS), the records of each annual review were manually tracked in spreadsheets, which are provided for the noted locations in Appendix A of this response. Annual reviews performed after the inspections were migrated to IMS are stored electronically in DTI's database. An example of an IMS record is also included in Appendix A of this response; however the remainder have not been included in this response (as they constitute hundreds of pages of inspections), but can be furnished upon request.

DTI respectfully requests that the proposed fine associated with Item #3 be withdrawn.

4. **§ 192.739 Pressure limiting and regulating stations: Inspection and testing.**

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

During PHMSA's field inspection, DTI technicians stated that some relief devices had not been inspected and no records of inspection were in the DTI's database. The following relief valves were not inspected at the required intervals for the period of 2003-2007:

1. Ellisburg Compressor Station fuel gas bottle inlet 1st cut regulator (Location ID CSN6361) has a regulator but the overpressure protection was not listed as inspected
2. Ellisburg Compressor Station relief valve (2" Axelson serial number 632280)
3. Stateline Compressor Station fuel gas bypass relief valve

<u>DTI Response:</u>

1) *The 1st cut regulator on the fuel gas volume bottle at Ellisburg Station should have been inspected annually, and documented in IMS. An inspection for this device was created on October 23, 2008 (the day after the PHMSA inspection). Subsequently, the device has been inspected per §192.739, and found to be in satisfactory condition.*
2) *The 2nd cut regulator on the Ellisburg Station fuel gas should have been inspected annually, and documented in IMS. An inspection for this device was created on October 23, 2008 (the day after the PHMSA inspection). Subsequently, the device has been inspected per §192.739, and found to be in satisfactory condition.*
3) *The fuel gas bypass relief valve at State Line Station is a tertiary protection device as it is downstream of a worker/monitor regulator set. The relief valve is only a secondary form of protection when the fuel gas run is operating on bypass, during inspection and maintenance of the worker/monitor set. In this instance, the location is manned by the DTI employee performing the work. For this reason, an annual inspection and capacity calculation are not required per §192.739 for the relief valve.*

DTI respectfully requests that the proposed fine associated with Item #4-3 be withdrawn.

5. **§192.743 Pressure limiting and regulator stations: Capacity of relief devices.**

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

DTI failed to conduct adequate annual reviews of pressure relieving devices to determine sufficient capacity at the five pressure limiting station devices noted below. DTI only physically checked the relief devices for pressure set point and operation. DTI did not determine adequate relief capacity. DTI had no documentation showing capacity calculations for the relief devices including comparison to rated relief design at their facilities needed for the required annual relief capacity determination.

1) Stateline Compressor Station location, feed line #16 with 1st and 2nd regulator stations with 2" Welmark relief valve
2) Stateline Compressor Station location Line #24 supplied by 10" dual port regulator with overpressure protection provided by 8"relief valve having a 6" inlet pipe
3) Oakford Region, Gas sales to Peoples Gas having a 6"x 8" Axelson relief valve
4) Oakford Region, Springdale meter and regulator station with relief valve overpressure protection
5) Mockingbird Hill Station #426 regulator and relief assembly

<u>DTI Response:</u>

1) *It has been determined that the relief valves installed on the feed to LN16 are slightly under-sized for the upstream regulators. DTI has installed smaller orifices in the regulators to correct this issue.*
2) *After reviewing the configuration of its overpressure protection devices on LN24 at State Line Station, DTI has determined that the relief valve does indeed require an annual capacity review. An inspection has been created in IMS for this task, and was completed on July 16, 2009 (see record of capacity calculation in Appendix E of this response).*
3) *Overpressure protection is provided at Oakford (feed to Peoples Gas) primarily by single regulators (in parallel) and secondarily by a pilot-operated shutoff valve (see drawing in*

Appendix B of this response), which closes upon sensing a pressure increase above the MAOP of the downstream piping. For this reason, the relief valve is not an overpressure protection device, and does not require an annual review of its capacity per §192.739.

4) *Overpressure protection at Springdale M&R is achieved by a worker/monitor regulator set (see drawing in Appendix C of this response) in accordance with §192.195. No relief valve is utilized at this site (there is a relief valve at the facility operated by TW Phillips, but is not a DTI overpressure protection device).*
5) *DTI would like to clarify this concern at Mockingbird Hill Station. This facility was not visited during the inspection, and overpressure protection is not achieved by a regulator at this site. Rather, the compressor engine is equipped with a high pressure shutdown switch, which is the primary device. Secondary protection is achieved by a relief valve, which is sized to relieve the capacity of the compressor in accordance with §192.743(see records in Appendix D of this response).*

DTI respectfully requests that the proposed fines associated with Item Numbers 5-3, 5-4, and 5-5 be withdrawn.

6. § 192.225 Welding procedures.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API 1104 (incorporated by reference, *see* §192.7) or section IX of the ASME Boiler and Pressure Vessel Code " Welding and Brazing Qualifications" (incorporated by reference, *see* §192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s).

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

During the field inspection of the Cove Point MD expansion project, DTI representatives indicated that there were no welding repair procedures on site in accordance with welding procedures qualified by §192.225; and, that welding repairs had been made to the DTI project facilities without having qualified procedures.

DTI Response:

It appears that there is some confusion concerning the information reviewed during the inspection..

DTI does not utilize separate procedures for the repair of welds. Rather, DTI's SOP 400/06 – "Welding; Repair and Removal of Defects" states that repairs are to be performed by the same *procedure used to make the original weld. These procedures were indeed on site and available during the construction of pipeline LN532.*

From SOP 400/03:

F. DTI's policy only allows one (1) weld repair without prior approval from Field Engineering - Engineering Services. The repair of a weld defect shall be in accordance with Welding Procedure Specifications used for the original weld. If a repair of a previously repaired area is needed personnel shall contact Field Engineering - Engineering Services for prior approval and a copy of the Multiple Weld Repair Procedure.

DTI respectfully requests that Item #6 be deleted from the Notice.

7. § 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 did not determine if the new 36" transmission line being installed for the Cove Point, MD expansion project could be blown down as rapidly as practicable as required by §192.179(c). DTI indicated that the Cove Point, MD expansion project blow-down design was made to match the blow-down design of the existing Cove Point parallel 30" transmission line. DTI did not take into consideration the larger size (36") of the new main, and just assumed the existing 30" transmission line blow-down capacity would be sufficient.

DTI Response:

While it is true that DTI's Design & Construction Manual did not offer guidance on the sizing of blow-offs on pipelines greater than 30" in diameter (this is being corrected in response to the Pilot II NOA; CPF-1-2009-1003M), Item #7 misstates a critical fact. The pipe on which DTI based its blow-off design was indeed a 36" pipeline, rather than 30" as noted in Item #7. There was no assumption that the sizing for a 30" pipeline would be adequate for a 36" pipeline.

DTI respectfully requests that Item #7 be deleted from the Notice.

8. **§ 192.163 Compressor stations: Design and construction.**

(e) Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI/NFPA 70, so far as that code is applicable.

DTI did not conform to the National Electrical Code requirements. At the time of the inspection, DTI transformers adjacent to main compressor building at Lightburn Station did not appear to be tied into a continuous grounding circuit in explosion-proof boxes, in accordance with NFPA 70 (2005) National Electrical Code, Article 250, for the following equipment:

(1) #5 engine pre-lube pump starter

(2) #4 engine pre-lube pump starter

(3) #3 engine pre-lube pump starter.

__DTI Response:__

DTI has addressed the concerns noted in Item #8. The transformers on the pre-lube pump starters at engines 3, 4, and 5 at Lightburn Station have been tied into the continuous grounding circuit as required per §192.163(e).

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Dominion Transmission, Inc.(DTI) a Compliance Order incorporating the following remedial requirements to ensure the compliance of DTI with the pipeline safety regulations:

1. In regard to Item Number 2 of the Notice, DTI must provide documentation that substantiates that all the drips in the Oakford Fifth Sands and Murrysville Storage Pools that can currently be blown down have been blown down within 180 days of date of final order.

2. In reference to Item Number 2, the 69 documented drips which have not been blown per DTI standard operating procedures (SOP), DTI must develop and execute a plan to find, make accessible, and modify as needed for drip blowing operations, those 69 identified drips within 365 days of date of final order.

3. DTI shall submit the results of the Proposed Compliance Order items above to the Director, Eastern Region, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration,

4. DTI shall maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Director, Eastern Region, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

DTI Response:

Per DTI's Response to Item #2 of this Notice, 42 of the drips in Oakford Storage Pool are inoperable at this time. The remaining 289 drips can, and have been blown in the past year.

Per a conversation with Mark Wendorff (Inspection Team Lead), it is DTI's understanding that the 180-day requirement noted in Item #1 of the Proposed Compliance Order means that DTI would need to blow each and every drip within Oakford Storage between the receipt of the final order, and 180 days later. DTI respectfully requests that Item #1 be amended to require documentation that all operable drips have been blown in the past year. The requirement to blow each drip within 180 days of the final order will result in the operation of these drips at the end of injection, when the presence of liquids is unlikely.

Additionally, DTI respectfully requests that the number of inoperable drips in Item #2 of this Proposed Compliance Order be amended to reflect the actual number at the time of the PHMSA inspection (63, per DTI's response to Item #2 of this Notice).