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November 20, 2020

Mary L. McDaniel P.E.
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
8701 S. Gessner, Suite 630
Houston, TX 77074

Re: Northern Natural Gas' Response to CPF-4-2020-1007M

Dear Ms. McDaniel:

In response to the Notice of Amendments dated October 30, 2020, Northern Natural Gas Company submits the following clarifications.

Item 1: § 192.303 Compliance with specifications or standards.

Northern Natural Gas' engineering standard 7503, Pipeline – Contract Specifications, specifically requires contractors to follow National Association of Corrosion Engineers standards for coating inspection.

The applicable section of ES 7503 is shown below:

10.3 The pipe coating will be tested utilizing an adjustable electric holiday detector immediately following the coating operation and/or prior to lowering-in for pre-coated pipe. All holidays and defects shall be repaired at the contractor's expense, and the repair approved by the company representative.

10.3.1 For plant applied fusion bonded epoxy coatings, test the coating in accordance with NACE SP 0490-2007 Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coatings of 10 to 30 mil.

10.3.2 For field applied coatings, test the coating in accordance with NACE RP 0274-2004 High Voltage Electrical Inspection of Pipeline Coatings.

An excerpt of NACE Standard SP 0490-2007, Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coatings, is shown below and contains the requirements for coating thickness and holiday detector voltages.

SP0490-2007

conditions change, it may be necessary to readjust the test voltage setting.

3.4 Alternatively, the pipe-to-electrode test voltage can be adjusted to the minimum test voltages described in Paragraph 3.5, which are commonly used in the pipeline industry. Output test voltages may be somewhat higher than these test voltage settings; the differential depends on grounding conditions and detector type.

3.5 The minimum testing voltage for a particular coating thickness shall be within 10% of the value determined by Equation (1):

$$\text{Testing Voltage} = V = K\sqrt{T} \qquad (1)$$

where V = peak voltage in volts, T = nominal coating thickness in µm, and K = 104 (constant)[1]

Table 1 gives calculated voltages for coating thicknesses of 250 to 760 µm (10 to 30 mil).

TABLE 1
Recommended Test Voltages for Various FBE Coating Thicknesses

Coating Thickness	Test Voltage[(A)]
250 µm (10 mil)	1,650 V
280 µm (11 mil)	1,750 V
300 µm (12 mil)	1,800 V
330 µm (13 mil)	1,900 V
360 µm (14 mil)	1,950 V
380 µm (15 mil)	2,050 V
410 µm (16 mil)	2,100 V
510 µm (20 mil)	2,350 V
640 µm (25 mil)	2,650 V
760 µm (30 mil)	2,900 V

[(A)] Rounded to the nearest 50 V.

3.5.1 The test voltage should be verified periodically (see Paragraph 3.3.3).

3.5.2 If an outerwrap is applied over the primary coating, the thickness and dielectric strength of the outerwrap material must be considered when determining or specifying the test voltage. Certain outerwrap materials may have electrical insulating properties equal to or greater than the coating.

3.5.3 Consumer-specified test voltages used at the coating site at the time of coating application shall not be exceeded during the on-site electrical inspection of the coating.

Similarly, an excerpt from NACE Standard RP 0274-2004, High-Voltage Electrical Inspection of Pipeline Coatings, as shown below, uses the same testing voltage formula albeit with a different constant.

Section 3: Testing Voltages

3.1 All testing voltages in this standard refer to DC or peak AC values.

3.2 The minimum testing voltage for a particular coating thickness shall be within 20% of the value determined from Equation (1) or (2), or as shown in Table 1:

$$\text{Testing Voltage} = 7{,}900\sqrt{T} \qquad (1)$$

where T = average coating thickness in mm;

$$\text{Testing Voltage} = 1{,}250\sqrt{T}$$

where T = average coating thickness in mils.

Table 1: Minimum Testing Voltage for Various Coating Thicknesses(A)

Coating Thicknesses		Testing Voltage
(mm)	(mils)	
0.51	20	6,000
0.79	31	7,000
1.6	62	10,000
2.4	94	12,000
3.2	125	14,000
4.0	156	16,000
4.8	188	17,000
13	500	28,000
16	625	31,000
19	750	34,000

(A) Thin-film coatings are not covered by this standard.

Since the NACE standard is referenced by its existing engineering standard, Northern Natural Gas does not believe amending its current standard is needed. Northern Natural Gas, however, will provide instruction to its construction inspectors during the annual inspector training on the need to record the voltage data and dry film coating thickness on the daily inspection reports.

Item 2: § 192.715 Transmission lines: Permanent field repair of welds.

Per the feedback received, Northern Natural Gas has added information to operating procedure 80.201, Repair of In-Service Pipelines, as shown below. Specifically, see Note 1 that was added to the table in 80.201.

5.10.3 Standard repair methods for girth weld defects:

Girth Weld Defects		Leak	Non-Leaking
Repair Method	**Standard**		
Cylinder Replacement	0075	x	x
Type B Pressure Containing Sleeve	8354	x	x
Weld Repair	8362	-	x
Mechanical Sleeve	-	x[1]	x[1]
Other method as determined by pipeline safety through reliable engineering test and analysis			
1 *Ensure bolt-on mechanical sleeve type transfers axial loads and provides full structural integrity.			

For further clarification, the following paragraph from Pipeline Research Council International Repair Manual is the basis for Northern Natural Gas' girth weld defect repair.

4.2.5 – Girth-Weld Defects

Girth-weld defects and certain other circumferentially oriented defects may be repaired in accordance with the criteria illustrated in Figure 30. Dents on girth welds are covered in Section 4.2.3. If the defect is not leaking, a fitness-for-service (FFS) evaluation may be performed to determine whether or not it is expected to affect the integrity of the pipeline. FFS evaluation requires knowledge of (1) pipe dimensions, (2) defect size, (3) material properties of base, weld, and heat-affected zone (HAZ) metal (including fracture toughness values if the defect is a type other than metal loss), and applied longitudinal stress. In effect, the operator should perform an FFS analysis or an engineering critical assessment (ECA) to show that the defect is acceptable as is or can be repaired by grinding or by grinding and weld metal deposition. To address this issue, informative Annexes J and K of CSA Z662(10) provide guidelines for ECA and acceptance standards based on fracture toughness. If the operator is not prepared to carry out such an assessment, the repair should be made by means of a Type B sleeve with its ends welded to the carrier pipe to provide some reinforcement in the longitudinal direction. There are also some clamp-on mechanical sleeves that provide for axial load transfer and structural integrity. These have been developed for and applied to offshore pipelines, but they could be used for onshore applications as well.

Item 3: § 192.911(c) What are the elements of an integrity management program?

Patrol is the mechanism or task that is used to gather multiple data items that are incorporated into the integrity management program. Operating procedure 80.501, Patrol Program, Section 5.4 lists the types of observations made during patrol, including: class location-construction of new structures along the pipeline, encroachment, leaks, shallow or exposed pipe, construction activity near the pipeline, and presence of markers, pipe or land movement. This data is used to determine class location and presence of high consequence areas in accordance with operating procedures 80.101, Class Location, and 140.101, Identification of HCAs and MCAs.

Patrol also is addressed in operating procedure 140.501, Prevention and Remediation, specifically in Appendix 140.501a, IMP-Prevention and Remediation Options Table. Northern Natural Gas has found patrol to be a very effective way to manage the risk of third-party damage and has developed several specific patrol options. First, Northern conducts two standard system wide aerial patrols per year. Second, an increased frequency aerial patrol program is conducted in the spring and fall each year to locate areas where drain tile installers are working to prevent damage to the pipeline. Third, additional mitigative patrol is used in areas of high construction activity. Fourth, an event-driven patrol is completed when a weather or outside force event has occurred; for example, an earthquake or a flood. These patrols are used as mitigation measures in the risk assessment process of the integrity management program. The aerial patrol is called "seasonal patrol," while the second and third types of patrol are called "other mitigative patrol" in the risk assessment.

Additionally, data is incorporated into the risk model annually in accordance with operating procedure 140.201 Data Gathering, Review and Integration, and 140.301, Risk Assessment and Prioritization of Covered Segments. The easiest way to show how the data is used in the model is by reviewing Appendix 140.201a, IMP Data Table, which documents the data and algorithm used for risk assessment.

The list below is taken from OP 140.201 (a) –Appendix A (IMP Table) and shows how some of the data gathered during patrol is used. Please note how third-party damage and weather and outside forces are quite dependent on the data gathered during patrol.

- Class location and HCA are used to determine the consequence of failure – example of how new structures along the pipeline are incorporated into the risk assessment
- Leaks are incorporated into the failure density scores for all threat types – example of leaks identified during patrol
- Third-party damage score
  - Farm activity level
  - One call violations and near misses – Example of construction activity near the pipeline identified by patrol
  - Encroachment frequency – Example of encroachment identified by patrol
  - Patrol frequency – Direct impact of patrol
  - ROW condition
  - Cover/surface type
  - Seasonal patrol – Direct impact of aerial patrol mitigation

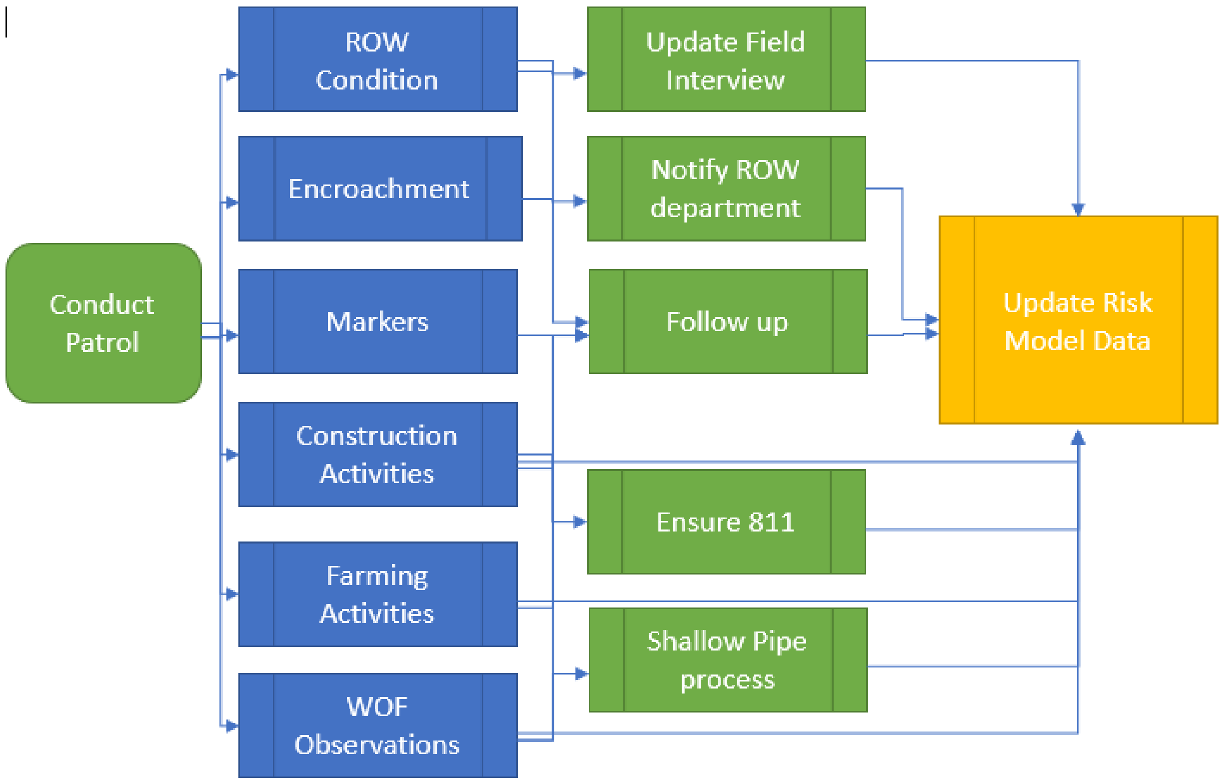
- Line of sight markers – Example of presence of markers identified by patrol
- Other mitigative patrol – Direct impact of patrol mitigation

- Weather and outside force
  - Land movement forces – Example of land movement identified by patrol
  - Weather forces – Example of pipe movement identified by patrol
  - Patrol frequency – Direct impact of patrol
  - Shallow cover present – Example of shallow or exposed pipe identified by patrol
  - Seasonal patrol – Direct impact of aerial patrol mitigation
  - Other mitigative patrol – Direct impact of patrol mitigation

A page from 140.201a – IMP Data Table is shown below with Patrols highlighted in yellow.

Third Party Damage Index				10, 12, 52-55, 63	100%												
Var #	**Factor or Formula**	**Definition**	**Related Procedure**	**Required Data**	**Weight**	**11**	**10**	**9**	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**	**0**
1	**One-call Activity Level**	The level of one-call activity, determined by the volume of calls, reflects construction activity.	OP 80.102	54	15%	Unknown	>24 tickets per year			6 to 24 tickets per year				<6 tickets per year			
2	**Farm Activity Level**	The level of farming activity in the area (i.e. low, moderate, etc.).	OP 80.501	-	15%	Unknown	Deep Tilled >12-inches deep Tree farm			Tilled less than or equal to 12-inches deep				Pasture			Non-agricultural
3	**Cover Depth, ft**	The depth of cover in ft.	OP 80.501	-	15%		0 to 18-inches Exposed			19 to 24-inches Unknown					25-36-inches	Over 36-inches	
4	**TP Failure Density**	Number of incidents per mile per year caused by third party activity. Incident is as defined by CFR 191.3, 191.23, and	OP 40.102	10, 12, 52	**15%**		≥1 per mile			0.001 to 1 per mile							Less than 0.001
5	***One-Call Violations and Near Misses***	*Number of one call violations and near misses from DIRT data*		-	**5%**		**≥1**										***No Violations***
6	**Anomaly Orientation**	The anomaly orientation (o'clock) location on the pipeline, in decimal time format.	OP 140.142	53	5%		0 to 120 degrees 240 to 360 degrees					120 to 240 degrees					
7	**Encroachment Frequency, per mile per year**	Number of encroachment reports per mile per year	OP 80.012	55	5%		≥10		≥5 and <10		≥1 and <5					≥0.1 and <1	<0.1 No encroachment
8	**Crossing Type (Topographic)**	The type of crossing.	ES 8709	63	5%		Major Waterway Airport Paved Road 4 lane		Railroad Paved road 2 lane		Foreign Line Crossing	Minor waterway		Other Road			No Crossing
9	**% SMYS**	Maximum Allowable Operating Pressure versus the Pipe Strength pressure. Pipe Strength pressure is at 100 %SMYS.	OP 80.701	-	**4%**	Unknown	≥0.72		≥0.60 and <0.72		≥0.50 and <0.60			≥0.30 and <0.50		<0.30	
10	**Patrol Frequency**	How often the pipeline is regularly patrolled.	OP 80.501		**4%**						Semiannually Unknown Null			Quarterly			
11	**ROW Condition**	The overall condition of the ROW (i.e. low congestion, moderate congestion, etc.). Pipeline access in case of mitigation or repairs or inspections, additions of structures or foliage within the ROW	OP 80.501	-	**4%**	Unknown	High congestion			Moderate congestion				Low congestion			Clear and Secure
12	**Cover/Surface Type**	Type of surface over the pipeline.	ES 0075	-	**4%**	Unknown	Soil					Water		Pavement	Structure		
13	***State Enforcement of Damage Prevention***	*Effectiveness evaluation of State's enforcement of damage prevention based on PHMSA data and NNG experience*			**4%**	***Unknow***	***Illinois***		***Wisconsin***				***Oklahoma***	***Kansas, Michigan, South Dakota, Texas***	***Iowa***	***Minnesota, Nebraska, New Mexico***	

The following flow chart shows how the patrol data flows from the field to the Integrity Management (IMP) risk model.



Item 4. § 192.605 Procedural manual for operations, maintenance, and emergencies.

Northern Natural Gas added "confirmed discovery" and its definition to operating procedure 10.101, Reporting and Notification of Pipeline and LNG Events, in December 2019.

Item 5. § 192.605 Procedural manual for operations, maintenance, and emergencies.

Northern Natural Gas added verbiage for coordinating with electric and other utilities to operating procedure 10.102, Emergencies, as shown below. In accordance with the management of change program, the procedure is routing internally for approval. The verbiage added is as follows:

> 5.7. Notify emergency responders that the initial exclusion zone and set back distance should be 1,320 feet (¼ mile) from the incident location. Once the situation is assessed and a potential impact radius is calculated, the exclusion zone *may* be re-evaluated.
>
> 5.8. *Coordinate with electric and other utility owners as needed during the emergency.*

If you have questions, please do not hesitate to contact me at (402-) 398-7715.

Sincerely,

Thomas Correll
Vice President, Pipeline Safety and Risk