POST INSPECTION MEMORANDUM

Inspector: Kuang Chu/UTC
Reviewed: Joe Subsits/UTC
Peer Reviewed: ____________________
Follow-Up Enforcement: No Violation
PCP* PCO* NOA WL LOC
Director Approval* ____________________

Date: September 16, 2011

Operator Inspected: Kinder Morgan Canada, Inc. **OPID:** 19585 **Region:** Western
Trans Mountain Pipeline
(Puget Sound) LLC

Unit Address:
Trans Mountain Pipeline (Puget Sound) LLC
Laurel Station
1009 East Smith Road
Bellingham, WA 98226

Unit Inspected: Trans Mountain Pipeline (Puget Sound) LLC **Unit ID:** 285

Unit Type: Interstate Hazardous Liquid (crude oil)

Inspection Type: I01 – Standard Inspection, I07 – IMP Field Verification, & Follow up, I08 – OQ Field Verification

Record Location:
Laurel Station
1009 East Smith Road
Bellingham, WA 98226

Inspection Dates: 8/22 – 26/2011

AFOD: 5 (I01-4.0, I07-0.5, I08-0.5)

SMART Activity Number:

Operator Contact: Patrick Davis
Phone: (360) 398-1541 **Fax:** (360) 398-7432 **Emergency:** 1-888-876-6711

Unit Description: The pipeline system from the Canada-United States border supplies crude oil to the Conoco-Phillips refinery at Ferndale was constructed in 1954. The pumping capacity is provided by Sumas Pump Station in Canada and by the two new pumps built at the Laurel

Station in 2008. In 1955, the pipeline was extended to Anacortes to supply crude oil to Shell and Tesoro refineries. In 1971, the pipeline system was extended to Cherry Point to supply crude oil to BP Cherry Point refinery. In total, 63.2 miles of pipeline was constructed in the State of Washington. The pipeline system can be broken down as follows:

- 15.3 miles of 20" pipeline between the Canada – US border to Laurel.
- 11.6 miles of 16" pipeline between Laurel Station and Ferndale Scraper Trap Station.
- 27.6 miles of 20" pipeline between Laurel Station and Burlington Scraper Trap Station.
- 9.0 miles of 16" pipeline between Burlington Scraper Trap Station and Anacortes Meter Station.

Facilities Inspected: The field inspection included Laurel Station, Ferndale Station, Burlington Scraper Trap Station, and Anacortes Meter Station. Portions of the pipeline right-of-way and several mainline valves were inspected and some manual valves were partially operated. All the cathodic protection test stations on Manley Road were inspected and pipe-to-soil potentials were taken. The breakout tanks T-170 and T-180 at Laurel Station, T-130 at Ferndale Station, and T-7 inside Shell Refinery in Anacortes were inspected.

Persons Interviewed: Patrick Davis, Supervisor, Corporation
Adam Lind, Operations Engineer

Probable Violations/Concerns:

There was one probable violation for the 12" surge relief line to breakout tank T-7 inside Shell Refinery in Anacortes as noted below:

1. **49 CFR §195.583 What must I do to monitor atmospheric corrosion control?**

   (b) During inspections you 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.

   Findings:
   During the field inspection of breakout tank T-7, it was noticed that the 12" pipe at soil-to-air interface had disbonded coating and there were signs of atmospheric corrosion at this location.

   Also, during the field inspection, the pipe-to-soil potential readings taken at the mainline valve station MU-43 indicated that the pipe was most likely shorted with electrical conduits or other components. Post inspection notes: On September 8, 2011 the operator's technicians identified a ½" temperature probe as the source of the short. An insulating union has been ordered and will be installed within a week.

<u>There was one item of concern as follows:</u>

1. The annulus between the carrier pipe and the casing under I-5 freeway at ML-6 most likely was partially filled with water. The vent at one end of the casing was damaged by highway mowing crew and the opening of the casing allowed the water to get inside the casing.

<u>During the review of the operator's O&M manual (PHMSA Form-3), the following deficiencies were found:</u>

1. **<u>49 CFR §195.106 Internal design pressure</u>**.

   (a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

   $$P = (2\,St/D) \times E \times F$$

   <u>Findings:</u>
   The Barlow's formula is not included in the operator's manual.

2. **<u>49 CFR §195.132 Design and construction of aboveground breakout tank.</u>**

   (a) Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

   <u>Findings:</u>
   This requirement is not included in the operator's manual.

3. **<u>49 CFR §195.424 Pipe movement.</u>**

   (a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

   <u>Findings:</u>
   This requirement is in operator's legacy manual (soon to be obsolete), but not in the new manual.

4. **<u>49 CFR §195.434 Signs.</u>**

   Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

   <u>Findings:</u>
   Although the signs at the field facilities show the name of the operator and the emergency contact telephone number, the operator's manual does not have this requirement.

5. **<u>49 CFR §195.559 What coating material may I use for external corrosion control?</u>**

Coating material for external corrosion control under Sec. 195.557 must--

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;

(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(c) Be sufficiently ductile to resist cracking;

(d) Have enough strength to resist damage due to handling and soil stress;

(e) Support any supplemental cathodic protection; and

(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

<u>Findings:</u>

The requirements for coating material properties are not in the operator's manual.

6. **<u>49 CFR §195.561 When must I inspect pipe coating used for external corrosion control?</u>**

(a) You must inspect all external pipe coating required by Sec. 195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

(b) You must repair any coating damage discovered.

<u>Findings:</u>

The requirement of (b) is not in operator's manual. However, it is in the legacy manual (soon to be obsolete).

7. **<u>49 CFR §195.563 Which pipelines must have cathodic protection?</u>**

(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

<u>Findings:</u>

The requirement of having operational CP no later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable, is not in operator's manual.

8. **<u>49 CFR §195.569 Do I have to examine exposed portions of buried pipelines?</u>**

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

Findings:
This requirement is not in operator's manual. The operator is currently using right-of-way (ROW) proximity form to document coating condition whenever the pipe is exposed along the pipeline ROW. A procedure and a new exposed pipe condition report form should be created for pipeline at any locations including ROW and facilities.

9. **49 CFR §195.579 What must I do to mitigate internal corrosion?**

(c) *Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.*

Findings:
The requirement of (c) is not in operator's manual. However, it is in their legacy manual (soon to be obsolete).

10. **49 CFR §195.583 What must I do to monitor atmospheric corrosion control?**

(b) *During inspections you 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.*

Findings:
The location of spans over water is not in operator's manual. However, it is in their legacy manual (soon to be obsolete).

11. **49 CFR §195.589 What corrosion control information do I have to maintain?**

(a) *You must maintain current records or maps to show the location of--*
   (1) *Cathodically protected pipelines;*
   (2) *Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and*
   (3) *Neighboring structures bonded to cathodic protection systems.*

(b) *Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.*

(c) *You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.*

Findings:
The corrosion control records retention of at least 5 years is not in operator's manual.

Follow up on the history of prior offenses that are still open:

Prior Offenses (for the past 5 years)		
CPF #	**What type of open enforcement action(s)?**	**Status of the regulations(s) violated (Reoccurrence Offenses, Implement a NOA Revision, Completion of PCO or CO, and etc...)**

Recommendations:

- A comprehensive team O&M inspection for Kinder Morgan Canada has never been conducted and it is recommended that a team inspection be scheduled within 2 years.
- Maintain normal inspection cycle.
- Issue a warning letter for probable violation and area of concern, and a notice of amendment for O&M deficiencies.

Comments:

During the exit interview, the operator indicated that all the items included in probable violation and areas of concern will be addressed and resolved. The revisions to O&M manual will take more time as they involve several different departments within the company.

Attachments:

- Form 3 Standard Inspection Report of a Liquid Pipeline Carrier
- Form 10 Breakout Tank Inspection Form
- Form 13 PHMSA Drug & Alcohol Questions
- Form 15 Operator Qualification Field Inspection Protocol Form
- Form 17 Supplemental SCC Questionnaire
- Form 19 Hazardous Liquid IMP Field Verification
- Field Data Collection Form
- Western Region-Unit Information Form

Version Date: 5/5/08