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November 8, 2012

Government Letter No.: 26768
File No. 2.11

Dennis Hinnah, Western Region Deputy Director
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
188 W. Northern Lights Blvd., Suite 520
Anchorage, AK 99503

Subject: NOA 5-2012-5016M

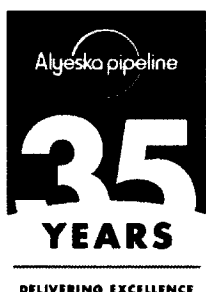
Dear Mr. Hinnah:

Alyeska Pipeline Service Company (Alyeska) provides this letter in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Notice of Amendment (NOA), CPF 5-2012-5016M dated August 9, 2012. The NOA addresses PHMSA's 2011 inspection of Alyeska's procedures for Operations and Maintenance, which took place on March 29 through April 1, 2011 in Anchorage, Alaska.

This letter is responsive only for those items which we are submitting amended procedures. Alyeska submitted information for Items 20 and 21 in our September 10, 2012 letter (GL 26525). Alyeska provides the following information in response to this NOA.

1. §195.52 Immediate notice of certain accidents

APSC's Operations Control Center (OCC) Procedure 3.02, Reporting Significant Events, states that notice is required when there is "Estimated property damage to Alyeska or others of \$50,000 or more" and does not list all of the factors in §195.52(a)(3) that contribute to cost, such as cleanup and recovery. APSC must amend OCC Procedure 3.02 to include all cost factors.



Certified No. 7002 2410 0005 0102 9825

Alyeska submits for your review amended procedure OCC-3.02, Reporting Significant Events, to include property damage costs of cleanup and recovery. (Please see Attachment A).

2. §195.55 Reporting Safety Related Conditions

APSC's Procedural Manual for Operations, Maintenance, and Emergencies (OM-1), Section 3.2.2, Reporting Safety-Related Conditions, does not state that a report must be filed when general corrosion is found that has reduced the wall thickness to less than required for the maximum operating pressure, as required by §195.55(b)(3). APSC must amend OM-1 Section 3.2.2 to include reporting of general corrosion.

At the time of the inspection, *OM-1, Procedural Manual for Operations, Maintenance and Emergencies*, Ed. 3, Rev. 2 (December 6, 2010), Section 3.2.1, included the language regarding filing a report when general corrosion is found. (Please see Attachment B).

Therefore, with respect to Item 2, Alyeska respectfully requests that PHMSA withdraw this finding and the proposed order directing amendment, as Alyeska's procedures comply with 49 CFR §195.55 and do not need to be amended.

3. §195.120 Passage of internal inspection devices

APSC's OM-1, Appendix A, indicates that ASPC compliance with 49 CFR §195.120 can be found in specification DB-180, Design Basis Update, but this specification does not provide procedures requiring new construction to accommodate the passage of instrumented internal inspection devices. APSC must show where compliance with 49 CFR §195.120 can be found.

At the time of the inspection, *DB-180, Design Basis Update*, Ed. 4, Rev. 29 (February 10, 2011), Section 2.12.2.2, Hydraulic Facility Design Requirements, included the requirement for new construction to accommodate the passage of instrumented internal inspection devices. (Please see Attachment C).

Therefore, with respect to Item 3, Alyeska respectfully requests that PHMSA withdraw this finding and the proposed order directing amendment, as Alyeska's procedures comply with 49 CFR §195.120 and do not need to be amended.

4. §195.228 Welds and welding inspection: Standards of acceptability

APSC's OM-1, Appendix A, references procedure W300, Pipeline Fabrication, for welding inspection. Procedure W300 does not list the revision date of API 1104 as required by 49 C.F.R §195.3. APSC must list the correct edition of the API 1104 in their procedures.

Alyeska submits for your review Specification W-300 amended to clarify the reference to the latest edition of API 1104 incorporated by reference in 49 CFR 192 and 49 CFR 195. (Please see Attachment D).

5. §195.402 Procedural manual for operations, maintenance, and emergencies

a) APSC's OM-1, Section 1, Operations and Maintenance Manual Description, incorrectly states: "The United States Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety (DOT/OPS), has jurisdiction over the pipeline system as it relates to the following processes." APSC must amend its manual to indicate that Pipeline and Hazardous Materials Safety Administration has jurisdiction over the pipeline system.

(b) APSC's OM-1, Section 7.2, Corrosion Control Supervisor Knowledge states that review of the corrosion control procedures is required every two years. All APSC procedures, including the corrosion control procedures, must be reviewed at intervals not exceeding 15 months, but at least once each calendar year.

Alyeska submits for your review OM-1, Section 1, amended to reflect that the Pipeline and Hazardous Materials Safety Administration (PHMSA) has jurisdiction over the pipeline system. (Please see Attachment E).

Alyeska submits for your review OM-1, Section 7.2, amended to reflect that corrosion control procedures must be reviewed at intervals not exceeding 15 months, but at least once each calendar year. (Please see Attachment F).

6. §195.402(c)(13) Procedure manual for operations, maintenance, and emergencies

APSC's OM-1, Appendix A references AMS-001, Document Process as the implementing document for compliance with §195.402(c)(13). During the inspection, APSC could not find the requirement for periodically reviewing the work done by the operator personnel to determine the effectiveness of the procedures in AMS-001. APSC must show where compliance with 49 C.F.R §195.402(c)(13) can be found.

Alyeska's AMS-001, Document Process, as well as AMS-027-005, PassPort Work Procedure, are the methods of compliance for §195.402(c)(13). Alyeska submits for your review, OM-1, Appendix A, amended to reflect the updated reference to AMS-027-005. (Please see Attachment G). Additionally, AMS-027-005, Sections 2.9-2.12 describe the operator's responsibilities in completing the work and following up with any required changes to procedures. (Please see Attachment H). In these cases, AMS-001, Documents Process, is used to implement the required changes.

7. §195.403(b)(1) and (2) Emergency Response Training

a) APSC's OM-1, Appendix A, references CP-35-1, Trans Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan as the implementing document for compliance with §195.403(b). APSC's computer records indicate that the review cycle for CP-35-1 is every 5 years. APSC must amend this procedure to be reviewed once each calendar year not to exceed 15 months.

b) APSC's OM-1, Appendix A, does not reference APSC procedure EC-71 Emergency Contingency Action Plans. APSC must include all procedures that address emergency response training in its list in OM-1.

Alyeska has changed the review cycle for *CP-35-1, Trans Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan*, to once a year. (Please see Attachment I).

Alyeska submits for your review OM-1, Appendix A, amended to include the EC-71 Emergency Contingency Action Plans for the pipeline, Valdez Marine Terminal and OCC. (Please see Attachment J).

8. §195.406(a) Maximum operating pressure

a) APSC's OM-1, Appendix A, references procedure OCC-2.07, Exceeded or Exceeding Maximum Operating Pressure (MOP) as the implementing document for compliance with §195.406. OCC-2.07 does not accurately describe how APSC determines their MOP. APSC must amend its procedures to clearly indicate how their MOP is defined at all locations. The criteria below have been utilized by APSC to determine MOP, but they are not included in procedure OCC-2.07:

- 1. On the suction side of a pump station, the hydraulic head from the closest upstream pinch point is maintained constant up to the station.*
- 2. De-rated as a result of corrosion, road crossings, dents, etc.*
- 3. The design pressure of individual components such as flanges, valves, pumps etc., as determined by the applicable code or the manufacturer.*

b) APSC's OM-1, Appendix A, references procedure OCC-2.07, Exceeded or Exceeding Maximum Operating Pressure (MOP) as the implementing document for compliance with §195.406. The procedure allows the operator to deviate from the procedure under certain very broad circumstances such as "a risk" to equipment, personnel or property. The procedure does not define any parameters or guidelines to assess the risks or the magnitude of impact of the risks to determine when deviation from the procedure is appropriate. The procedure also does not give any guidelines as to what actions should be taken if the procedure is to be deviated from.

Alyeska submits for your review OM-1, Section 5.3, amended to document the method Alyeska uses to determine MOP. (Please see Attachment K).

Alyeska's procedure OCC-2.07, Exceeded or Exceeding MOP, contains language regarding the expectation that controllers will deviate from the procedure based on their experience and to protect equipment, personnel or property. This language is consistent in all OCC procedures.

9. §195.420(b) Valve maintenance

APSC could not show PHMSA procedures that require valves to be inspected not exceeding 7 ½ months, but at least twice each calendar year. APSC must amend OM-1, Appendix A, and reference where the required procedures may be found.

At the time of the inspection, OM-1, Ed. 3, Rev. 2 (December 10, 2010), Section 4.1.1, contained language describing the waiver, 49 Fed.Reg. 28729, granted to Alyeska by PHMSA in 1982 allowing 8 months between valve inspections, instead of 7½ months. (Please see Attachment L).

With respect to Item 9, Alyeska respectfully requests that PHMSA withdraw this finding and the proposed order directing amendment, as Alyeska's procedures comply with 49 CFR §195.420(b) and do not need to be amended.

Alyeska submits for your review, OM-1, Appendix B.1, amended to reflect the 8 month interval for valve inspection. (Please see Attachment M).

10. §195.420(c) Valve Maintenance

APSC could not show PHMSA documentation that requires protection from unauthorized operation or vandalism. Alyeska must amend OM-1, Appendix A, and reference where this required procedure may be found.

Alyeska submits for your review, OM-1, Section 5.7.1, amended to include more specific information regarding how mainline valve protection from unauthorized operation or vandalism is accomplished. (Please see Attachment N).

11. §195.426 Scraper and sphere facilities

APSC's OM-1 does not reference procedures for receiving and launching pigs from Pump Station 8 in a safe manner.

During the PS01 booster pump leak, the use of the PS08 launcher/receiver was required. In that event, project specific procedures were developed based on the specific circumstances of the event.

Alyeska does not anticipate launching or receiving a pig from PS08. If the launcher/receiver at PS08 were to be used during an ILI run, the procedures would be written specific to the run, the pig, and the circumstances. All ILI runs are completed on a project basis, and the procedures to support the PS08 launcher would be written for the project.

Therefore, OM-1 will not reference procedures for receiving and launching pigs from PS08.

12. §195.428(a) Overpressure safety devices and overfill protection systems

APSC's OM-1, Table B.3 and Appendix A do not list all of APSC's overpressure safety devices to be checked annually nor does it list the procedures to perform these tasks. The following are devices not listed:

- 1) Kuparuk pressure transmitter 3I-PT-013A (see CPF 5-2008-5002);*
- 2) Sadlerochit shut down pressure switches at GC-2, FS-1, and FS-3;*
- 3) Thermal relief valves;*
- 4) Break out tank over fill protection devices;*
- 5) Procedure for testing PS07 Shut down pressure switches; and*
- 6) RGV 36, 65, 98, 121 Pressure Transmitters.*

APSC must amend OM-1, to include all overpressure safety devices and procedures to perform these tasks.

Alyeska submits for your review, OM-1, Table B.3, amended to include those devices listed above which Alyeska committed to include per GL 26525, dated September 10, 2012. (Please see Attachment O).

Alyeska submits for your review, OM-1, Appendix A, amended to include the procedures necessary to complete the annual maintenance on the overpressure safety devices. (Please see Attachment P).

13. §195.444 CPM leak detection

APSC's OM-1, Appendix A, references CS-238, Control System Software Management and CS-238-1, UCOS SCADA Management as the implementing documents for compliance with §195.444. APSC could not find a reference to API 1130 in either C5238 or CS-238-1. APSC must amend its procedures to indicate that APSC's leak detection system meets API 1130.

Alyeska submits for your review DO-14-1, *Trans-Alaska Pipeline System Description Manual (SR)*, Section 2.3.5, Leak Detection Systems, amended to accurately reflect Alyeska's systems, as well as their basis in API 1130. (Please see Attachment Q).

Alyeska submits for your review OM-1, Appendix A, amended to reflect DO-14-1 as the implementing document for compliance with §195.444. (Please see Attachment R).

14. §195.559 What coating material may I use for external corrosion control?

APSC's OM-1, Appendix A does not reference MR 48, Trans Alaska Pipeline Maintenance and Repair Manual, Table 18.1, Pipe Coatings as the implementing document for compliance with §195.559. APSC must reference all appropriate procedures including MR-48 in Appendix A.

Alyeska submits for your review OM-1, Appendix A, amended to include MR-48, Table 18.1, and the related coating procedures as methods of compliance for §195.559. (Please see Attachment S).

15. §195.561 When must I inspect pipe coating used for external corrosion control?

APSC could not locate a procedure that requires inspection of coating before lowering the pipe into the ditch or submerging the pipe. APSC must reference or write a new procedure requiring inspection of pipe coating prior to lowering the pipe into the ditch or submerging the pipe.

The requirements for inspecting pipe prior to covering it are contained in the specific coating specifications. Alyeska submits for your review OM-1, Appendix A, amended to list the coating specifications as a method of compliance.(Please see Attachment T).

16. §195.561 When must I inspect pipe coating used for external corrosion control?

APSC's OM-1, Appendix A, does not reference MR 48, Trans Alaska Pipeline Maintenance and Repair Manual, Table 18.1, Pipe Coatings as the implementing document for compliance with §195.561. MR-48, Table 18.1 is the information APSC used to show that it complies with 49 C.F.R §195.561. Alyeska must reference MR 48 in Appendix A.

Alyeska submits for your review OM-1, Appendix A, amended to include MR-48, Table 18.1. (Please see Attachment U).

17. §195.563(a) Which pipelines must have cathodic protection?

APSC's OM-1, Appendix A, references MP-166-3.22, Pipeline Cathodic Protection System as the implementing document for compliance with §195.563(a). MP-166-3.22 does not indicate that cathodic protection has to be installed within one year. APSC must indicate how it complies with 49 C.F.R §195.563(a).

Alyeska submits for your review DB-180, Design Basis Update, Section 1.7, amended to reflect which pipelines must have cathodic protection per §195.563(a). (Please see Attachment V).

18. §195.563(c) Which pipelines must have cathodic protection?

APSC's OM-1, Appendix A, references MP-166-3.22, Pipeline Cathodic Protection System as the implementing document for compliance with §195.563(c). MP-166-3.22 does not indicate that cathodic protection has to be installed on effectively coated pipelines. APSC must indicate how it complies with 49 C.F.R §195.563(c).

Alyeska submits for your review DB-180, Section 1.7, amended to reflect that effectively coated pipelines must have cathodic protection per §195.563(c). (Please see Attachment W).

19. §195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?

APSC's OM-1, Appendix A, references MP-166-3.22, Pipeline Cathodic Protection System. MP-166-3.22 does not indicate that cathodic protection test leads have to be installed frequently enough to obtain adequate and accurate electrical measurements of the CP, and that test leads are afforded slack to prevent undue stress. APSC must indicate how it complies with 49 C.F.R §195.567.

Alyeska submits for your review DB-180, Section 1.7, amended to reflect that test leads must be installed frequently enough to obtain adequate electrical measurements of the cathodic protection per §195.567. (Please see Attachment X).

At the time of the inspection, *MR-48, Trans Alaska Pipeline Maintenance and Repair Manual*, Ed. 3, Rev. 20 (February 7, 2011), Section 17.7, Paragraph 3, included the requirement that test leads must be afforded slack to prevent undue stress. (Please see Attachment Y).

Therefore, with respect to Item 19, Alyeska respectfully requests that PHMSA withdraw this finding and the proposed order directing amendment, as Alyeska's procedures comply with 49 CFR §195.567 and do not need to be amended.

22. §195.585 What must I do to correct corroded pipe?

APSC's OM-1, Appendix A, references B-512, Pipeline Corrosion Evaluation Procedures as the implementing document for compliance with §195.555. B-512 does not discuss reducing the pressure or repairing the pipe. APSC must amend OM-1 to state how it complies with 49 C.F.R §195.585(a) and (b).

Alyeska submits for your review, OM-1, Appendix A, amended to include a reference to MR-48, Section 2.6, Pipeline Repairs. (Please see Attachment Z).

Alyeska believes that this response will provide adequate amended procedures and clarification on these findings. If you have any questions or need additional information, please contact Joseph Robertson at (907) 787-8061.

Sincerely,

Michael W. Pegnor

Attachments: A - Z

cc: Chris Hoidal, DOT/PHMSA



Department Operating Procedure Operations Control Center

Subject: Reporting Significant Events

Number: OCC-3.02

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Revision: 9 Draft A

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- b. Alyeska will also notify other affected internal and external stakeholders of significant or anticipated events using Form 2124, e-mailing the electronic form to DL, Event Notification.
- c. The appropriate duty officer will be notified via phone when Form 2124, "Event Notification" is sent out.
- d. DOT requires telephone notification as soon as possible to NRC (1-800-424-8802) if a failure of a pipeline system releases crude or natural gas AND results in any of the following:
 - 1) Death or hospitalization
 - 2) Unintentional fire or explosion
 - 3) Damage or loss > \$50,000; including cost of clean up and recovery, value of lost product and property damage.
 - 4) Pollution to any body of water
 - 5) In Alyeska's judgement was significant, even if it did not meet the criteria of the above listed categories.

B. Restoration

Upon receiving clearance from the Incident Commander or senior company official in charge, return the system to normal operations.

C. Documentation and Follow-up

1. Copies of computer logs, Incident Reports, Event Notifications, OCC log book entries, and all other documents pertaining to the incident will be checked for accuracy and filed.
 - a. If the OCC Supervisor or designee is notified of an event normally reportable on Form 2124, the name of the person notifying OCC, the date and time should be entered in the Controllers log book.
 - b. If a telephone notification is received by OCC and no other documentation is done (e.g. Form 2124, Spill Report, EMS Reports, etc.), and a decision is made not to send out a Form 2124, this fact must be entered in the Controllers log book. (The commitment for logging telephone notifications when there was no other documentation done was made to the JPO in a meeting on event notification on 10/14/95.)
2. If the OCC is responsible for causing the event, the OCC Supervisor is required to complete the requirements contained in *DSK-19*, "OCC Tracking and Trending Process," and the applicable portions of an IMPACT report as required by *49 CFR 195.402(d)(4)*. Details on how to fill out these forms and the criteria for any necessary investigation or analysis are found in *SA-38, Corporate Safety Manual*.
3. The quality of the performance of this procedure shall be incorporated into the overall critique of the event, as required by *49 CFR 195.402(d)(5)*.

END OF PROCEDURE

electronic system is not available for some reason. The online data entry screen can be found at <http://opsweb.rspa.dot.gov/cfdocs/opsapps/pipes/main.cfm>.

The DOT coordinator submits the Accident Report to DOT as soon as practicable, but not later than 30 days after discovery. Additionally, if Alyeska discovers any changes to the information reported, or additions to the original report, a supplemental report will be filed within 30 days.

3.2 Safety Related Conditions

The following are Safety-Related Conditions, as defined by the DOT/OPS, 49 CFR 195.55. All personnel are responsible to recognize conditions that may potentially be classified as safety-related conditions and to elevate the potential issue so that a determination can be made by appropriate SME's regarding whether or not a Safety Related Condition exists. Following that determination, a Safety-Related Condition report will be generated and submitted if required.

Field operations and maintenance personnel, controllers or corrosion personnel are expected to recognize potential safety-related conditions.

3.2.1 Identifying Safety-Related Conditions

The following are conditions that may need to be reported on a Safety-Related Condition Report:

1. Corrosion that has lessened the pipeline wall thickness to less than that required for the maximum operating pressure, or localized pitting to a degree where leakage might result, is normally identified by Alyeska Engineering as part of an evaluation of the extent of corrosion using Alyeska specification B-512, *Pipeline Corrosion Evaluation Procedures*, in accordance with Integrity Management Monitoring Program Procedures.
2. Unintended movement or abnormal loading of a pipeline by environmental causes, such as earthquake, landslide or flood, that impairs its serviceability is normally identified during routine surveillance and monitoring activities or during post-earthquake reconnaissance, in accordance with [OCC-13.02-SR](#), *Known Seismic Events* (Emergency Operating Procedure), and is normally recorded in ROWMIS.
3. Material defects or physical damage that impair the serviceability of the pipeline are normally identified by operations, maintenance, or inspection personnel during routine facility operation, maintenance, or inspection activities, and are documented in accordance with [AMS-027](#), *Maintenance Work Management Process*. Maintenance work orders or final design packages may be generated to address resolution of defects or damage.
4. Malfunctions or operating errors that cause the pressure of a pipeline to rise above 110% of MOP are normally identified by OCC Controllers and may be confirmed by hydraulic engineers who conduct an evaluation of abnormal conditions to determine if pipeline pressure exceeded 110% of MOP. Data recorded on the UCOS System host computer is used to model pipeline pressures. In addition, an investigation of abnormal conditions using [AMS-024](#), *Incident Reporting, Investigation, and Analysis Process*, is conducted.
5. A leak in the pipeline that constitutes an emergency may be identified by personnel or the public and oil spill response procedures are immediately implemented. The spill reporting system is used to report oil spills and to record information regarding response activities. Additional information about oil spill response activities is documented using ICS documentation.

- d. Leak detection and control systems
- e. Restarting the pipeline

2.12.2.2 Hydraulic Facility Design Requirements

The following criteria shall apply to the hydraulic design of pipeline, pumping, DRA injection, receiving, terminal, storage and other facilities:

1. Pipeline and facilities shall be designed so that pipeline crude oil pressures required to meet the design flow or throughput requirements are maintained at or below the MAOP of the pipe at all locations during normal operation.
2. The pipeline design shall limit crude temperatures to the range between -20°F and 145°F .
3. Pump station head rise and DRA injection requirements established by the hydraulic design shall be used when establishing design parameters for the design of mainline pumps and DRA injection facilities. See [Section 4.1](#), “Main Pumps and Drivers,” and [Section 4.14](#), “Drag Reducing Agent (DRA) Injection Facilities.”
4. Crude oil vapor pressures must be maintained by the hydraulic design below local atmospheric pressure at all possible atmospheric tank injection or relief sites.
5. Slack line operation is permitted by the hydraulic design. However, the design must consider the following potential impacts of slack line operation:
 - a. Buckling of the pipe due to negative pressure loading
 - b. Leak detection sensitivity and detection time
 - c. Pipe vibration, structural loading and fatigue
6. Waxing of the pipe shall be either prevented or accounted for by the hydraulic design. Pig launchers and receivers shall be installed as required to permit scraper and corrosion inspection pig coverage of all cross country pipeline segments.
7. Check valves are required at all pump stations to permit station bypass.
8. All pump stations shall be provided with suction side and discharge side block valves for station isolation and maintenance.
9. Storage for crude oil or hydrocarbons received into TAPS to prevent interruptions to pipeline or producer throughput should be a consideration of the design process.
10. Storage for crude oil or hydrocarbons at pipeline terminal sites to prevent interruptions to pipeline throughput should be considered as part of the design process.

2.12.2.3 Measurement and Monitoring Design Requirements

The following design criteria apply to the need to monitor hydraulic parameters. See [Section 1.12](#), “Crude Oil Metering,” and [Section 1.9](#), “Instrumentation Systems,” for further requirements:

1. Custody transfer metering is required at all crude oil connections to non-pipeline facilities.
2. Pipeline flow metering is required at the suction and discharge of all operating pump stations with pumping units or relief tanks and at the entrance to pipeline terminal facilities, to assist in operating the pipeline, and to support leak detection system operation as part of the hydraulic design. Mainline flow measurements must be nonintrusive to allow passage of pigs.



Specification W-300 Piping Fabrication

and/or ASTM material specification, prior to shipment of shop fabricated pipe spools, and prior to starting fabrication of field fabricated piping.

10. When requested, postweld heat treatment (PWHT) procedures and copies of all records of weld heat treatment as described in paragraph 3.5.10 shall be submitted prior to nondestructive and pressure testing and authorization to use the procedure from Alyeska is received. PWHT procedures shall include support types, number and locations, thermocouple types, number, method of attachment, locations and calibration method, heating and cooling methods, heating and cooling rates and holding temperatures, and furnace atmosphere.
11. Radiographic films, results of other NDT reports and any other types of weld examinations, and the records pertaining to them shall be submitted.
12. Charts or other records of pressure tests in accordance with specification *P-307, Facilities Piping Pressure Testing*.
13. If applicable, the fabricator shall furnish Alyeska with a certified, reproducible copy of Form P-4A, Manufacturer's Data Report for Fabricated Piping, for all piping fabricated under Section I, ASME Boiler and Pressure Vessel Code.

1.5 Welding Procedure Qualification

1. Ensure that welding procedures are qualified in accordance with the applicable code or standard and this specification. The fabricator or a subcontractor shall be responsible for the welding performed by their personnel, and shall conduct the required welding procedure qualification tests.
 - a. Several procedure qualification records (PQRs) can be used to support one welding procedure specification (WPS) or several WPSs can be prepared from one PQR providing the essential variables are within the requirements of the appropriate code used to qualify the PQR.
 - b. Qualification of a WPS requires both radiographic and destructive examination unless otherwise approved by Alyeska.
 - c. WPSs qualified for ASME B31.4 and ASME B31.8 piping may be in accordance with ASME Section IX or API 1104.
2. Welding performed in accordance with 49 CFR 192 and 49 CFR 195 must be performed in accordance with welding procedures qualified under Section 5 of API 1104 or ASME Section IX. The quality of the test welds used to qualify the welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s). **The applicable edition of API 1104 or ASME Section IX used for welding procedure qualification shall be the latest edition incorporated by reference in 49 CFR 192 and 49 CFR 195.**
3. Alyeska will review WPSs and PQRs with the test results and provide written approval or rejection of the welding procedures. Alyeska will reject a WPS that is not in compliance with this specification.
4. Adhere to the qualified and Alyeska-approved WPSs all times during welding. Do not deviate without written approval from Alyeska. In the event that a change of an essential variable is required, qualify and submit a new WPS for Alyeska approval.

Section 1. Operations and Maintenance Manual Description

The Trans Alaska Pipeline System (TAPS) was originally designed, constructed and tested in accordance with the requirements of *49 CFR 195*, “Design approval, Construction Oversight, and Acceptance” prior to startup, was provided by the United States Department of Interior, acting on behalf of all federal agencies as required, by the TAPS Agreement and Grant of Right-of-Way.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has jurisdiction over the pipeline system as it relates to the following processes:

- **Reporting:** *49 CFR 195, Subpart B*, “Reporting Accidents and Safety-Related Conditions”
- **Design:** *49 CFR 195, Subpart C*, “Design Requirements”
- **Construction:** *49 CFR 195, Subpart D*, “Construction”
- **Pressure Testing:** *49 CFR 195, Subpart E*, “Pressure Testing”
- **Operation and Maintenance:** *49 CFR 195, Subpart F*, “Operation and Maintenance”
- **Qualification and Documentation Program:** *49 CFR 195, Subpart G*, “Qualification of Pipeline Personnel”
- **Corrosion:** *49 CFR 195, Subpart H*, “Corrosion Control”

This manual addresses the general requirements for each of the above processes. However, its primary purpose is to fully address Alyeska’s implementation of the operations and maintenance procedural requirements in *49 CFR 195, Subpart F*, “Operation and Maintenance.”

These regulations, specifically *49 CFR 195.402(a)-(e)*, require that Alyeska prepare and follow a manual of written procedures for conducting and handling systems, components, and practices associated with transporting crude oil to market during:

- Normal Operations
- Maintenance activities
- Abnormal Operations
- Emergencies

The body of this manual is intended to provide a high level overview of the TAPS system and how the methods of compliance and records generated are managed by Alyeska Pipeline Service Company.

[Appendix A](#)- Cross Reference of DOT/OPS Code Implementing Documents and Records lists Alyeska’s implementing procedures (method of compliance) and records generated to demonstrate compliance with each section of Part §195 that is applicable to TAPS.

Questions about the content and intent of the DOT/OPS pipeline safety regulations and this manual should be addressed to the Alyeska DOT Coordinator (ext. 8363).

7.2 Corrosion Control Supervisor Knowledge

Alyeska requires that the supervisor/subject matter expert (SME) responsible for insuring compliance with corrosion control procedures have a thorough knowledge of those procedures through a combination of the following:

The Alyeska corrosion supervisor/SME responsible for each area of practice listed in [Table B.7](#) in [Appendix B](#) is the document owner of the relevant corrosion control procedures. As document owner, the supervisor/SME is responsible for compliance with the procedure and for the technical review and revision of the procedure annually, at least once per calendar year, not to exceed 15 months (or more frequently as needed). This technical review will be documented in the Revision History section of each procedure, verifying that the current supervisor/SME has the appropriate knowledge of the procedure content and requirements. The review follows the [AMS-001, Documents Process](#) and uses the Management Actions and Commitments (MAC) software system to initiate the review and to document that the review has been completed. When completing the MAC Action, the SME shall attest that they have completed the review in either the "Progress Comments" or "Completion Comments" in the MAC system.



Alyeska Management System

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Manager and if work will not be implemented pending a future event or condition.

2.9 Perform Work

The Implementer is accountable to perform the work. The Implementer consults with the Planner, Coordinator, or Engineer to determine if a revision to the schedule or work plan is necessary if the following conditions exist:

If the need for engineering is identified during the course of performing the work

Changes to existing engineering requirements are identified

As-found conditions make the plan unworkable, or the work instructions are insufficient to guide the work.

The Implementer will inform the 1st Line Supervisor if work is started and left incomplete with system(s) returned to operational status. The 1st Line Supervisor will take actions necessary to document and monitor the incomplete work.

This could include:

Lock and tag the item to prevent its use

Report and monitor the incomplete work as a Compliance Violation

Design Change Verification Request (*Form 10562*) approved by the Assigned Engineer if within the scope of an engineered modification

Other monitoring suitable to provide heightened awareness and prevent extended deferral of work completion.

The Implementer will generate a separate Supplemental Work Request for work identified outside the scope of a Preventive Maintenance Work Order, or a step in the Preventive Maintenance Work Order that cannot be completed. A Supplemental Work Request must be approved by the 1st Line Supervisor and will reflect an appropriate priority relevant to the scope of the remaining work. The Preventive Maintenance Work Order can be CLOSED.

The Implementer or 1st Line Supervisor will return the Work Order to the Planner if the Work Order Task(s) need details added or refined due to as-found conditions during implementation. The Planner will re-evaluate the scope of work and requirements. The Work Order will be re-approved and rescheduled.

Refer to Appendix E, “*Work Process Flow*,” for expanded work flowchart for the performance and completion of work.

2.10 Complete Work

After work is completed at the work site, a verification walkdown by the 1st Line Supervisor of the system is required if work performed meets the following conditions:

Process equipment was drained / cleared.



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Blinds were installed and / or removed.

Temporary piping, hoses, etc were utilized as process equipment.

Car seals were removed or installed or jumpers installed / removed.

The work involves major project or significant work activities.

Changes to control systems or parameters have occurred.

The Implementer will correct any drawing, procedure, tag number, or other documentation discrepancies noted during the implementation of the work in accordance with the appropriate processes, for example, *Form 1241, Preventive Maintenance Change Request, AMS-009, Alyeska Master Drawing Update Process, AMS-004-06, Alyeska Equipment Tag Procedure.*

The Implementer will enter completion comments, labor hours and other information on a frequent basis to sufficiently support shift changes and other communication requirements. As exceptions, labor hours and detailed completion comments are not required for contract funding authorization Work Order Task(s) that do not have a detailed scope of work or minor work tasks where blanket Work Orders will capture labor hours. Refer to Appendix C, "*Work Order Completion*," for common work order completion information.

The Implementer notifies the 1st Line Supervisor when work is complete. The 1st Line Supervisor, or their designee, performs a final review of the work and hard copy documentation. If they are determined to be unsatisfactory, the 1st Line Supervisor informs the Implementer of the need for rework.

When the work and documentation is deemed satisfactory, ensure all labor hours, M&TE, and comments are entered and place task in FINISHED status. Forward all documentation required in Appendix D, "*Electronic Work Order Records*" to the Documenter.

The Documenter will ensure that relevant documents are maintained with the Work Order and scanned via the OLE process into PassPort or other appropriate databases in accordance with Appendix D, "*Electronic Work Order Records*." The Documenter will ensure redlines and updated drawings are forwarded to the appropriate personnel in accordance with the applicable processes.

Once all criteria are met, the 1st Line Supervisor, or designee, sets Work Orders to COMPLETE status in the work management system. By setting a Work Order to COMPLETE, all Work Order Task(s) are automatically set to COMPLETE if they are not already CANCELLED. This completion signifies that all actions required in the scope were completed, cancelled, or are contained in another WO.

The preferred media for the storage of work order (WO) records is electronic. Unless specifically stated in the WO task instructions, original hard copy records need only be maintained if the WO record is for an engineered modification or it is so large that it becomes impractical to scan and store electronically. The latter is at the discretion of the Documenter. If the record is to be



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retained in original hard copy form, the Documenter will add a note to the electronic completion comments as follows: "Record is maintained as hard copy."

Once electronic documentation is verified complete, the original hard copy work order package may be discarded unless otherwise noted in the work order task instructions or the [CW-200](#), Record Retention Schedule.

2.11 Review/Trend Work History

Periodically the Accountable Manager reviews established measures to identify patterns or trends of asset failures and the types of maintenance work being planned and scheduled (e.g., repair, minor modifications, emergency, preventive, predictive monitoring, etc.). Measures are retrieved from maintenance management systems, and understanding of the patterns or trends is gained through communication with Implementers, Operators, Planners, and Coordinators.

For significant analysis equipment failures including all failures resulting in pipeline shutdowns, the Equipment and Diagnostic Resource Center (EDRC) will conduct a failure analysis. If a more in-depth analysis is necessary, the EDRC will contact equipment SMEs as needed, and engage the follow-up on the identified issues.

Results of trending and failure analysis are used to identify opportunities for reducing environmental and operational impacts, and improving resource allocation effectiveness. If trending identifies the need to improve or change maintenance or implementation methods, the Maintenance Manager uses [AMS-026](#), *Equipment Maintenance Analysis Process*.

2.12 Output

Work scope is completed, accepted, and documented. In some cases, supplemental work is generated in the form of a work request.

Document Details[Revision History](#)**Unique ID:** CP-35-1 Volume 1**Document Title:** Trans Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan, Volume 1, Regulatory Volume**Document Type:** Manual**Revision Number:** 3**Edition:** 3**Effective Date:** 08/17/2012**Last Revision:** Approval to publish Routine Amendment, Government Letter 26203**Comments:** Government Letter 25985: Revisions to Vessel Distribution Information Vessel distribution information has been updated in Section 3, Table 3-7. Approval to publish Routine Amendment, Government Letter 26202 Government Letter 25988: Revision to Dispersant and Logistical Support Information Dispersant and C-130 aircraft references have been removed in Section 3.5.1 and Table 3-28. Approval to publish Routine Amendment, Government Letter 26202 Government Letter 25989: Tank Inspection Waiver Amendment Tank inspection information for Tank 220 has been updated in tables 2-4 and 3-3 to match the terms of the ADEC waiver granted in Government Letter 26024 on May 25, 2012. The waiver is provided in Section 2.6. Approval to publish Routine Amendment, Government Letter 26203 Government Letter 25996: Miscellaneous Minor Edits Amendment Minor edits include updates to Section 3.6.2.2 (update description of ?non-circulating hydraulic? equipment), Table 3-7 (correct location information for snow melter), Table 3-12 (update radio information to include new equipment), and Section 1.1.2 (update recon checklists to match checklists in the Field Operations Guide).**Method Of Compliance:** Yes**Issuing Department:** Emergency Preparedness and Compliance**Document Owner Position:** Emergency Preparedness and Compliance Manager**Document Owner 1:** WILLSON, WESLEY C**Document Owner 2:****Document Publisher:** KORTENHOF, KIMBERLY J**Applies to Facility:** All (Company-Wide/General)

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Performed: N

Review Date: 12/21/2011

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Scheduled 12/21/2012
Review Date:

Change
Management: No

The primary records demonstrating safe operation of the pipeline during normal operation consist of OCC log books and electronically recorded operations data, captured on the data historian. Significant changes in pipeline operations are recorded electronically as logged events. Operational data such as pressure, temperature, and flow are also recorded in the data historian.

5.3 Controlling Pipeline Pressure

The Trans-Alaska Pipeline System is a telescoped API 5L carbon steel pipeline comprised of pipe with five different pressure capabilities. There are two wall thicknesses (0.462-inch and 0.562-inch), and three specified minimum yield strengths (60 ksi, 65 ksi and 70 ksi).

Pressure control of the pipeline is maintained by a series of process pressure controllers and overpressure (relief) controllers, located at pipeline system facilities, and a backpressure regulator and overpressure (relief) controller in Valdez.

The pressure indicating controllers (PIC) for each pump station suction (PIC-X01) and discharge (PIC-X02) mainline unit speed control are the primary controllers that maintain steady-state pressures. The OCC Controller is responsible for ensuring that these controllers maintain system pressure below Maximum Operating Pressure (MOP).

The Maximum Operating Pressure Limit (MOP Limit) is defined as the maximum pressure that a section of pipe can be re-rated to. The MOP Limit is limited to lowest pressure from any of the following:

- The maximum internal pressure of the pipe as determined by the design factor from the applicable code, the nominal wall thickness and the specified minimum yield strength for the pipe;
- The design pressure of individual components such as flanges, valves, pumps, etc., as determined by the applicable code or manufacturer;
- A percentage of the hydrotest pressure as determined by the applicable code;
- De-rated as a result of corrosion, road crossings, dents, etc.

The DOT Maximum Operating Pressure (DOT MOP) or (MOP), as specified in 49 CFR 195, is the maximum pressure at which a pipeline or segment of a pipeline may be normally operated. MOP is determined on TAPS in the following way:

- At hydraulic pinch points, the "MOP Limit" described in this section is applicable.
- Between hydraulic pinch points, a straight line interpolation between pinch points defines the MOP.
- On the suction side of a pump station, the hydraulic head from the closest upstream pinch point is maintained constant up to the station.

Mainline pressure relief is a critical safety function; PS01, 03, 04, 05 and 09 have relief valves (PICVs) that divert crude oil from the pipeline into a relief tank to prevent over pressuring the mainline.

The devices associated with relief are:

- PICV relief valves
- Upstream relief block valves
- Downstream relief block valves

Section 4. Waivers and Agreements

Alyeska operates based on several waivers and agreements between APSC and PHMSA regarding specific requirements for complying with pipeline safety regulations. These agreements and waivers have been incorporated into implementing manuals and procedures and are included here for reference.

4.1 Valves

4.1.1 Valve Inspection Waiver

On June 21, 1982 PHMSA granted APSC a waiver from §195.420(b). This waiver allows APSC to “inspect two times each calendar year, with intervals between inspections not to exceed 8 months, each main line valve to determine that it is functioning properly.” This gives APSC 8 months instead of 7 ½ between valve inspections. (47 Fed. Reg. 28729)

4.1.2 Valve Consent Agreement

This agreement provides for Alyeska to maintain and inspect at twice yearly intervals certain valves on TAPS. This agreement settles a Petition for Reconsideration of the Final Order in CPF No. 55501 and the NOPV CPF No. 5-2002-5035 concerning valve inspections. This agreement supersedes all prior agreements with respect to valve inspection. The valves that are subject to the requirements of this agreement are included in Table B.1 of Appendix B. The Valve Consent Agreement can be found in MAC GL 8857.

4.2 Cathodic Protection

Alyeska has received several waivers from specific PHMSA cathodic protection requirements, providing relief from mainline, pump station and terminal piping coating requirements. These waivers are listed below for reference and the requirements are included in applicable implementing procedures and manuals.

- 60 FR 44930 Thermally insulated pump station and terminal piping
- 60 FR 44931 Thermally insulated mainline piping on TAPS
- Letter from PHMSA dated December 13, 1999 allowing smart pig runs every three years

4.3 Pipe Movement

Pipe movement is defined as the change in position of a pipe due to lifting or jacking, as opposed to the result of changes in pressure, temperature, backfill, or temporary supports.

On November 10, 2004, PHMSA (formerly RSPA) granted Alyeska’s petition for a waiver of the pipeline safety regulation related to operating pressure during routine maintenance of the aboveground segments of TAPS (69 FR 67212). PHMSA §195.424(a) normally requires an operator to reduce the pressure of a pipeline to not more than 50 percent of the maximum operating pressure whenever the line pipe is moved. However, because of the unique design of TAPS that allows the pipe to move freely within a design range, pressure reduction during routine maintenance was determined to be “not necessary and ... disruptive and burdensome to pipeline operations.”

5.6.2 Maintenance Work Order System

The PassPort Work Management Module is an electronic system used to manage TAPS maintenance activities. When maintenance work is identified as a result of inspection or other operational activity, a work request is generated for review and approval. Once the work request is approved, a work order is generated to track details of the work performed and as a record for historical purposes.

Part of the PassPort Work Management System includes a Preventive Maintenance System for the management of preventive maintenance activities. The PMWO system is designed to automatically identify which PM tasks are coming due, and to generate a PMWO prior to the scheduled due date. PMWOs are automatically generated at the facility where the task is done.

PMWOs for regulatory required maintenance activities are identified with a priority code 03, which defines the task as mandatory and non-deferrable. This prioritization ensures that DOT/OPS-driven scheduled maintenance and inspection activities are completed as required by regulation. Scheduled maintenance tasks with a priority code 03 must be performed by the regulatory due date in order to maintain compliance with regulations. Internal Alyeska due dates can be changed as long as the regulatory requirements are not exceeded.

The PMWO includes instructions for completing the task. The PMWO itself may contain the established work procedure, or may refer to a separate procedure that the individual must obtain to complete the activity.

Once the work is completed, the technician fills out the PMWO with any required information, signs the work order, and returns it to the Supervisor for review and approval. The task is then closed in PassPort. Task performance history reports are available from PassPort to verify that regulatory-driven tasks are completed within required frequencies.

Each PMWO for DOT/OPS-regulated tasks must be reviewed annually, not to exceed 15 months. To accommodate this review and possible correction of PMWO, each PMWO undergoes a review by operations and maintenance personnel as part of the task performance. If changes are required, *AMS-026-001, Preventive Maintenance (PM) Change/New PM Process*, provides instructions for processing PMWO changes.

5.7 Security

5.7.1 Facility and Asset Security

Facilities have perimeter fencing where necessary. Access to pump stations, mainline valves, the Valdez Marine Terminal, or other critical facilities is controlled by integrated security systems that combine physical barriers, electronic systems, and security personnel to control and grant access to authorized individuals.

Mainline valves are housed within perimeter barriers and fencing with signs prominently posted, denoting appropriate warnings and contact information. The structure is secured by company approved locking devices and an intrusion detection alarm system is monitored by the Operations Control Center (OCC).

Principal responsibility of security includes protection of facilities, personnel, safeguarding of material and preventing unauthorized entry of persons or materials. This is accomplished by the introduction of security protective measures that focus on:

commercial electric power. The only other sources of permanent electric power for the VMT are two diesel-powered emergency generators, termed the “lifeline generator” and the “emergency generator (EG-1).”

For detailed information, refer to *PG-16, Valdez Marine Terminal Power Generation Facility Operating Manual*, and *TV-18, Valdez Marine Terminal Vapor Recovery Operating Manual*.

2.3.4 SCADA

Unusual and difficult terrain as well as environmental considerations demands safeguards and system capability beyond existing norms. To satisfy these requirements, a system which combines digital, analog logic, local and remote control was designed and implemented. The SCADA (Supervisory Control and Data Acquisition) system is designed to permit the Pipeline or Terminal Controllers to have control of the pipeline and Terminal systems operations. There are two (2) alternate data paths based on digital microwave and fiber optic communications that support the SCADA system.

Additional system reliability is provided by using redundant equipment in critical areas and the use of backup data communication paths. The SCADA equipment is a distributed system with primary control workstations located at the OCC in Anchorage, and the secondary control workstations located at the AOCC in Palmer. These workstations provide for communications between the OCC and pump station main supervisory equipment.

2.3.5 Leak Detection Systems

The pipeline, pump station, terminal, and ship-loading facilities have been designed and constructed to be as secure and as leak-proof as possible. Alaska's history of seismic activity has been carefully reviewed, and potential earthquakes have been categorized as (1) design operating earthquakes and (2) design contingency earthquakes. A design operating earthquake may be described as a probable earthquake of severe magnitude which may occur during the life of the system. All pump station facilities which are critical to normal operation, safety, and containment of oil will remain well within their design stress limits and will withstand such loading. Pump station facilities are designed to remain "tight" during a more severe design contingency earthquake with no resultant oil leakage or major structural damage. Structures may experience some deformation without failure from a design contingency earthquake. All control systems associated with the safe shutdown of the pipeline are designed and tested to operate during and after a design contingency earthquake.

Operationally, the leak detection system, in conjunction with aerial and ground surveys of the pipeline, aids in prevention or detection of spills. Contingency plans are available for every portion of the system to effect immediate response and corrective actions for leaks or spills.

Leak detection systems utilized for monitoring the pipeline were designed and maintained to meet API-1130 as stipulated under 49 CFR 195.444. These systems consist of the following:

- Deviation Alarming - Deviation alarming (DA) performs flow and pressure monitoring and execute as part of the SCADA System logic. This set of logic performs rapid time-weighted averaging on pump stations flow rates, pipeline segment flow balances (upstream pump station discharge flow rate versus downstream pump station suction flow rate), and pump station mainline pressures. Should any of these differ from a baseline measurement by more than a configurable alarm threshold, an alarm is generated and presented to the pipeline controller for analysis and, if needed, appropriate action.

- **Line Volume Balance - Line Volume Balance (LVB) is a Line Balance system, as described in API-1130, and executes on the Oracle-based control system historical accounting system. LVB performs calculations every 30 minutes after receiving data from the SCADA System and performs gain/loss calculations based on turbine meter volumetric data. Should gain/loss data deviate by a statistically significant amount, an alarm is sent to the SCADA System for presentation to the pipeline controller for analysis and possible action, if required.**
- **Transient Volume Balance - Transient Volume Balance (TVB) is a Computational Pipeline Monitoring (CPM) system as described in API-1130. TVB is a complex system that performs mass balance modeling of the pipeline to look for unexplained imbalances within the pipeline. Should an unexplained imbalance exceed a threshold for a period of time, TVB will send an alarm to the SCADA System for presentation to the pipeline controller for analysis and appropriate action, if required.**

2.3.6 Operations Control Center

Operation of the pipeline is controlled from the Operations Control Center (OCC) at the Valdez Marine Terminal. The center is operated by the Pipeline and Terminal Controllers.

The Pipeline Controller is responsible for monitoring and controlling the flow of crude oil into and from the first pump station at Prudhoe Bay to the entrance of the Valdez tank farm. The Terminal Controller is responsible for receiving oil from the pipeline, measuring, storing, and delivering the oil to tankers.

Using control center data, the Pipeline Controller controls pipeline flow rates, system start-up and shutdown, starting and stopping of individual pumps at all PS, pump station pressures, utilization of pump station relief tanks, and pipeline and pump station block valves.

The control center data used by the Pipeline Controller is derived from a UCOS control system. The control system consists of PC based computers in the Operations Control Center and six remote stations, one at each operating pump station on the pipeline. The UCOS control system automatically and continuously scans data from all of the remote stations. Approximately 200 data signals and 1,400 status and alarm signals are reviewed cyclically by the computer every ten seconds.

Incoming information is displayed, on demand, on visual display panels and, if desired, can be printed. Alarms and commands are automatically displayed on the Controllers console screens and stored for retrieval at any time. All critical equipment such as the computer visual display units and control panels are duplicated and have an automatic changeover capability.

Communication for the system is via microwave with a satellite backup system.

The Terminal Controller controls the flow of pipeline oil to specific storage tanks and from tanks to waiting tankers. The flow of oil is directed through loading lines and manifold valves to the desired tanker berth. The Oil Movements Department measures the quality of the oil delivered, determines the quantity of tanker cargoes, documents all crude oil receipts and deliveries, and coordinates the entire loading operation with ship personnel.

The Ballast Water Treatment (BWT) plant, Power House which supplies steam/power generation, and vapor recovery facilities are operated from separate control rooms located near each unit. Certain alarm conditions are also transmitted to the OCC.

Berth loading arm valves are controlled by Berth Operators, but only after the Terminal Controller has activated a permissive control. It is possible to close these valves from either the berth or the OCC.

- URS Corporation (2003), *Seismic Hazard Analysis of Trans-Alaska Pipeline System*, prepared for Alyeska Pipeline Service Company, under contract with D. J. Nyman & Associates, Houston, TX, URS Job No. 33749262.
- Woodward-Lundgren and Associates (1974). *Summary Report, Basis for Active Fault Crossings for the Trans-Alaska Pipeline System*, Report prepared for Alyeska Pipeline Service Company, Houston, Texas, 115 p, "Appendices."

1.7 Corrosion Control

Like the original corrosion control systems, new designs should provide external corrosion protection for a minimum of 30 years. Methods employed consist primarily of the application of coatings, tape wrap, and cathodic protection systems. Internal coatings or linings as well as corrosion inhibitors and cathodic protection are utilized at some locations for internal corrosion control. Existing corrosion control facilities are considered adequate and do not require remediation or replacement unless corrosion control levels that do not meet regulatory requirements are found.

Use of TAPS is assumed to be indefinite and therefore, design life considerations for developing and implementing new corrosion control systems shall be economically maximized.

In addition to preserving and extending the useful life of TAPS facilities, corrosion control systems shall provide compliance with appropriate regulatory requirements and accepted industry standards. Corrosion control measures that satisfy the requirements of the National Association of Corrosion Engineers (*NACE International*) standards and recommended practices are considered adequate to fulfill these requirements.

All buried pipeline segments that are constructed, relocated, replaced, or otherwise changed, must have cathodic protection in operation no later than one year after completion of the change. All buried pipeline segments that have an effective external coating must have cathodic protection. All buried pipeline segments must have test leads installed frequently enough to obtain adequate and accurate electrical measurements of the cathodic protection.

Corrosion control measures and materials not previously utilized on TAPS should be tested or have their effectiveness demonstrated prior to implementation. Materials should be evaluated using standard, industry accepted tests. These tests should include corrosion resistance tests of metal alloys for corrosive service, coating and tape wrap tests for moisture penetration, abrasion resistance, cathodic disbondment, flexibility, temperature sensitivity, shear resistance, dielectric properties, and chemical resistance. Performance tests and evaluations should also be conducted for new cathodic protection systems and materials.

1.7.1 Internal Corrosion Environment

The pipeline's internal environment consists primarily of crude oil that also contains natural gas liquids (NGLs), solids, salts, and water. Locations such as crude oil storage tanks, piping dead legs, and crude oil piping with low or cyclical flow rates are locations where internal corrosion could result from water that may separate from the oil. Microbiologically-influenced corrosion (MIC) can occur at these locations.

Other internal corrosive environments can be found in:

- PS01 and VMT vapor recovery systems;
- pump station and mainline refrigeration systems;

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Other internal corrosive environments can be found in:

- PS01 and VMT vapor recovery systems;
- pump station and mainline refrigeration systems;

17.7 Cathodic Protection Test Stations

A cathodic protection test station consists of a terminal board mounted on a support pipe with wires that connect to the mainline pipe and to belowground cathodic protection system components such as anodes, coupons, and permanent reference electrodes, and to nearby foreign structures such as road casings or foreign pipelines, if present. Test stations with anode wires also provide the anode-to-pipe electrical connections necessary for galvanic cathodic protection to function. Cathodic protection test stations also provide the primary contact for monitoring the level of cathodic protection along the pipeline. It is important to maintain their integrity in order to facilitate viable cathodic protection and monitoring capabilities on TAPS.

Given that test stations' buried wires may run in several directions below the ground, they are very susceptible to damage from excavation/backfill activities. Care must be taken to identify damage as it occurs during excavation and to avoid damaging the wires during backfill operations. Damage to test station components or wires that occurs during excavation or maintenance activities shall be repaired while the excavation is open.

During installation, care must be taken to provide adequate looping or slack so backfilling will not unduly stress or break the lead and the lead will remain mechanically secure and electrically conductive.

Notification of observed test station damage not related to maintenance activities (e.g., flooding, glaciation, vandalism) shall be sent to Integrity Management Engineering.

NOTE

Whenever the buried mainline pipe is exposed, contact the cathodic protection SME in Integrity Management Engineering to determine if a CP Coupon Test needs to be installed. If required, install in accordance with [Section 17.7.4](#).

17.7.1 Existing Cathodic Protection Test Stations

There are several types and configurations of cathodic protection test stations installed on TAPS. For maintenance and repair purposes, they have been grouped into the following five categories. However, some test stations may not fall into any of these categories. Contact Integrity Management Engineering for direction regarding remedial action for unclassified test stations.

Category 1 **Original Construction Test Stations** (figures [17.11](#) through [17.17](#))

These were installed during original pipeline construction. They are no longer being maintained to their original configuration. Some original construction test stations are no longer needed and may be removed, while others must be replaced with current test station configurations.

Category 2 **Big Fink Test Stations** (figures [17.4](#), [17.18](#) through [17.20](#))

There are several configurations in this category. Most were installed in conjunction with remedial anode installations in areas previously identified with low cathodic protection levels. Therefore, most Big Fink test stations contain anode-to-pipe connections that must be maintained.