U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

VIA UPS GROUND - 1ZWR25880392703656

August 9, 2012

Mr. Mike Joynor
Senior Vice President of Operations
Alyeska Pipeline Service Company
3700 Centerpoint Drive
Anchorage, Alaska 99503

CPF 5-2012-5016M

Dear Mr. Joynor:

From March 29 through April 1, 2011, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected Alyeska Pipeline Service Company's (APSC) procedures for Operations and Maintenance in Anchorage, Alaska.

On the basis of the inspection, PHMSA has identified the following apparent inadequacies found within APSC's plans and procedures, as described below:

1. **§195.52 Immediate notice of certain accidents.**
(a) Notice requirements. At the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, the operator of the system must give notice, in accordance with paragraph (b) of this section, of any failure that:
(1) Caused a death or a personal injury requiring hospitalization;
(2) Resulted in either a fire or explosion not intentionally set by the operator;
(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;

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.

2. **§195.55 Reporting Safety-Related Conditions:**
(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving pipelines in service:
(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.
(2) Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, that impairs its serviceability.
(3) Any material defect or physical damage that impairs the serviceability of a pipeline.
(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.
(5) A leak in a pipeline that constitutes an emergency.
(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
(b) A report is not required for any safety-related condition that—
(1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;
(2) Is an accident that is required to be reported under §195.50 or results in such an accident before the deadline for filing the safety-related condition report; or
(3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

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 that 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.

3. **§195.120 Passage of internal inspection devices.**
(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

APSC's *OM-1*, Appendix A, indicates that APSC compliance with 49 C.F.R § 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 C.F.R § 195.120 can be found.

4. **§195.228 Welds and welding inspection: Standards of acceptability.**
(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (ibr, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

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.

5. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
(a) General. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

(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.

6. **§195.402 Procedural manual for operations, maintenance, and emergencies.**
(c) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:
(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

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.

7. **§195.403 Emergency Response Training.**
(b) At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:
(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and
(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

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*.

8. **§195.406 Maximum operating pressure.**
(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

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.

9. **§195.420 Valve maintenance.**
(b) Each operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

APSC could not show PHMSA procedures that require valves to be inspected not exceeding 7½ months, but at least twice each calendar year. APSC must amend *OM-1*, Appendix A, and reference where the required procedures may be found.

10. **§195.420 Valve maintenance.**
(c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

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.

11. **§195.426 Scraper and sphere facilities.**
No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.

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

12. **§195.428 Overpressure safety devices and overfill protection systems.**
(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition,

and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

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 31-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.

13. **§195.444 CPM leak detection.**
Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system.

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 *CS238* or *CS-238-1*. APSC must amend its procedures to indicate that APSC's leak detection system meets API 1130.

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

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.

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

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.

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

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.

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

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).

18. **§195.563 Which pipelines must have cathodic protection?**
(c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection.(see Note below) Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.

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).

19. **§195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?**
(a) General.
(2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.
(b) Installation. You must install test leads as follows:

(1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

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.

20. **§195.583 What must I do to monitor atmospheric corrosion control?**
(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:
If the pipeline is located: Onshore, Then the frequency of inspection is: At least once every 3 calendar years, but with intervals not exceeding 39 months

APSC could not provide a procedure for the frequency of atmospheric corrosion monitoring. ASPC must demonstrate how it complies with 49 C.F.R §195.583(a).

21. **§195.583 What must I do to monitor atmospheric corrosion control?**
(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.

APSC's could not provide a procedure for what to do if atmospheric corrosion is discovered. APSC must show how it complies with 49 C.F.R §195.583(c).

22. **§195.585 What must I do to correct corroded pipe?**
(a) General corrosion. If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you—
(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or
(2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
(b) Localized corrosion pitting. If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

APSC's *OM-1, Appendix A*, references *B-512, Pipeline Corrosion Evaluation Procedures* as the implementing document for compliance with § 195.585. *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).

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 90 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

It is requested (not mandated) that Alyeska Pipeline Service Company maintain documentation of the safety improvement costs associated with fulfilling this Notice of Amendment (preparation/revision of plans, procedures) and submit the total to Dennis Hinnah, Deputy Director, Western Region, Pipeline and Hazardous Materials Safety Administration. In correspondence concerning this matter, please refer to **CPF 5-2012-5016M** and send all documents to our office at 188 W. Northern Lights Blvd., Suite 520, Anchorage, AK 99503. For each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Dennis Hinnah
Deputy Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 B. Flanders (#133780)

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*