U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W Dakota Ave , Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 23, 2008

Mr John Lau
Director, Transmission Operations
Alaska Pipeline Company
401 E. International Airport Road
P.O Box 190288
Anchorage, AK 99519-0288

CPF 5-2008-0009M

Dear Mr. Lau

On May 7-11, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected your integrity management program in Anchorage, Alaska.

As a result of the inspection, it appears that your written procedures are inadequate to assure safe operation of the pipeline as follows:

1. **§ 192.905 How does an operator identify a high consequence area?**

   (b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

   § 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment.

1a) Alaska Pipeline Company (APC) does not provide adequate procedures for the documentation of field verification of identified sites. As an example, AS&G offices in Area A7 were excluded as an identified site in 2004, but included as an identified site in 2006 The annual review for 2005 stated that the identified sites were "verified" but there is no indication of the depth of that verification process In addition, field data varies in its depth based primarily on the personnel performing the verification

1b) APC documents the definitions of identified sites and the methods for their identification in a memorandum that is not referenced by its procedures or program document.

2. **§ 192.911 What are the elements of an integrity management program?**

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

2a) The APC process for developing the BAP does not provide requirements for keeping the BAP up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method

3. **§ 192.907 What must an operator do to implement this subpart?**

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment.

(b) ***Implementation Standards.*** **In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (ibr,** ***see*** **§ 192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.**

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) ***Threat identification.*** **An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see § 192.7), section 2, which are grouped under the following four categories: (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; (2) Static or resident threats, such as fabrication or construction defects; (3) Time independent threats such as third party damage and outside force damage; and (4) Human error.**

(b) ***Data gathering and integration.*** **To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.**

(c) ***Risk assessment.*** **An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.**

3a) There are no procedures to require documenting the threat analysis performed by APC No documented basis exists for the exclusion of cyclic fatigue or other threats, and no evaluation is provided for applicable threats.

3b) APC has not used a conservative approach in its data analysis regarding the fact that there is an absence of records to demonstrate that pre-1970 piping is not low frequency ERW piping

3c) There are inadequate procedures to ensure that the APC risk assessment supports the objectives identified in Sections 5.3 and 5.4 of ASME B32.8S-2001

3d) The APC IMP does not have a documented process for validating its risk assessment

4. **§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat. (1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external

§ 192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA). (b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in— (1) ASME/ANSI B31.8S (ibr, *see* §192.7), section 6.4; NACE RP0502–2002 (ibr, *see* § 192.7); and § 192.925 if addressing external corrosion (ECDA).

§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, see § 192.7), section 6.4, and in NACE RP 0502–2002 (ibr, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917(e)(1).

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect Examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502–2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502–2002).

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and (iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502–2002.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments;
and
(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE RP0502–2002.)

- **Item 4A: § 192.923 and § 192.925(b)**

  The APC ECDA Procedure does not specify as a minimum types of records identified in NACE section 3 as records to be obtained during the pre-assessment phase of ECDA.

- **Item 4B: § 192.923 and § 192.925(b)(1)**

  The APC IMP does not require that the basis for indirect examination tool selection be documented and the basis is not provided in IMP records.

- **Item 4C: § 192.923 and § 192.925(b)(1)**

  The APC ECDA Plan does not specify the more restrictive criteria to be applied during the pre-assessment phase of the ECDA process

- **Item 4D: § 192.917(e)(1), § 192.923 and § 192.925(b)**

  The APC ECDA Plan provides no procedures for the integration of ECDA data with foreign line crossings or encroachments

- **Item 4E: § 192.923 and § 192.925(b)(2)**

  APC has not documented nor applied more restrictive criteria during the indirect examination step of its ECDA process

- **Item 4F: § 192.923 and § 192.925(b)(3)**

  APC has no documented process for determining the root cause of significant corrosion activity, nor is there any method documented for examining the implications of significant corrosion activity to other sections of the pipeline

- **Item 4G: § 192.923 and § 192.925(b)(3)**

The APC ECDA Plan does not require documentation of the basis upon which indications are reclassified and reprioritized in accordance with any of the provisions that are specified in NACE RP0502-2002, Section 5 9

- **Item 4H: § 192.923, § 192.925(b)(4) and § 192.939**

The APC IMP does not contain provisions for the performance of remaining life calculations to determine the appropriate reassessment intervals for its HCA pipeline segments

- **Item 4I: § 192.923, § 192.925(b)(4) and § 192.939**

The APC IMP does not specify any criteria for evaluating whether conditions discovered by direct examination of indications indicate a need for reassessment at an interval less than specified in 192 939.

- **Item 4J: § 192.923, § 192.925 and § 192.945(b)**

APC has not established or monitored additional criteria to evaluate long-term ECDA program effectiveness.

- **Item 4K: § 192.907(a) and § 192.923**

The APC IMP processes have not incorporated feedback mechanisms that enable continuous improvement of the ECDA Plan.

5. **Remediation**

§ 192.907 What must an operator do to implement this subpart?

(a) ***General.*** **No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment.**

§ 192.933 What actions must be taken to address integrity issues?

(a) ***General requirements*** **An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary**

reduction in operating pressure using ASME/ANSI B31G (ibr, *see* § 192.7) or AGA Pipeline Research Committee Project PR–3–805 (''RSTRENG''; ibr, *see* § 192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. *(See* appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation.*—

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2 /3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

- **Item 5A: § 192.907 and § 192.933(b)**

  The APC IMP does not provide a definition for discovery that defines when sufficient information is available to determine the significance of an anomaly.

- **Item 5B: § 192.907 and § 192.933(b)**

  The APC IMP does not provide adequate procedures specifying how the date of discovery is to be documented.

- **Item 5C: § 192.907 and § 192.933(d)**

  The APC IMP does not require that a temporary pressure reduction or shutdown of the pipeline occur upon discovery of all immediate repair conditions

- **Item 5D: § 192.907 and § 192.933(d)**

  The APC IMP does not have adequate procedures for recording and tracking anomalies identified as monitored conditions.

- **Item 5E: § 192.907 and § 192.933(a)**

  The APC IMP has no program procedures identifying the appropriate actions to take when remediation timeframes cannot be met

- **Item 5F: § 192.907 and § 192.933(c)**

  The APC IMP has no program procedures identifying the appropriate actions to take to justify why a schedule cannot be met and why a schedule change will not jeopardize public safety.

- **Item 5G: § 192.907 and § 192.933(c)**

  The APC IMP has no program requirements to specify how notification is to be accomplished in the event the operator cannot meet the remediation schedule or provide a temporary reduction in operating pressure

6. **Continual Evaluation and Assessment**

   § 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

   (a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a

covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

- **Item 6A: § 192.937(a)**

The APC IMP has no procedures to determine if an earlier reassessment is necessary than that required by 192 939

7. **Preventive and Mitigative Measures**

§ 192.907 What must an operator do to implement this subpart?

(a) ***General.*** **No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment.**

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(e) ***Actions to address particular threats.*** **If an operator identifies any of the following threats, the operator must take the following actions to address the threat.**

(5) ***Corrosion.*** **If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933, the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.**

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) ***General requirements.*** **An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment.** ***(See*** **§ 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr,** ***see*** **§ 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing**

computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

- **Item 7A: § 192.907, § 192.917(e)(5), and § 192.935(a)**

  The APC IMP has no documented process to check for the potential threats of internal corrosion or SCC

- **Item 7B: § 192.907 and § 192.935(a)**

  The APC IMP has no documented, systematic, decision-making process for deciding which P&M measures are to be implemented

8. **Performance Measures**

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, see §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

- **Item 8A: § 192.945(a)**

  The APC performance measure report ending 12/31/04 was submitted to PHMSA on 3/09/05 (nine days late)

9. **Management of Change**

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

- **Item 9A: § 192.909(a) and § 192.911(k)**

The APC Management of Change Process does not fully implement the requirements of the Rule and the referenced ASME B 318S, Section 11 requirements The following are specific areas noted

- Inadequate documentation of the reason for changes prior to implementation,
- No documented criteria for what constitutes a significant program change for the purpose of notifying PHMSA,
- Inadequate procedures to consider impacts of changes to pipeline systems and their integrity;
- MOC procedures do not address all of the nine basic elements of the change process as defined in ASME B31.8S,
- Physical pipeline system changes are not addressed by the MOC process and are not therefore evaluated for their potential impact on the IMP,
- Procedures do not require that equipment or system changes are identified and reviewed before implementation

10. Quality Assurance

§ 192.7 Incorporation by reference.

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or (3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person— (1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or (2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

- **Item 10A: § 192.911(l)**

  APC does not have a documented Quality Assurance Plan, therefore, no annual review of a QA Plan is being performed

- **Item 10B: § 192.911(l)**

  APC does not have a documented process by which corrective actions for identified program weaknesses are tracked to completion and validated as effective

- **Item 10C: § 192.911(l)**

  APC does not have processes to ensure vendor supplied services meet quality requirements and these processes are not documented as part of a quality program

- **Item 10D: § 192.915(a)**

  The APC IMP does not identify qualification requirements for supervisory personnel and does not establish that these personnel meet these requirements   Note   This is specific to qualifications beyond those provided by the OQ program.

- **Item 10E: § 192.915(b)**

The APC IMP does not provide qualification requirements or evidence of training to meet these requirements for personnel evaluating assessment results nor for personnel who perform activities within the Integrity Management Program

- **Item 10F: § 192.915(c)**

  Qualifications for three APC line locators have lapsed with respect to required training for Abnormal Operating Conditions.

- **Item 10G: § 192.7(a)**

  APC has not documented its position with regard to "should" statements appearing in codes and standards.

11. Communications Plan

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework *(see* § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* § 192.7) for more detailed information on the listed element.)

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—
(1) OPS; and (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

- **Item 11A: § 192.11(m)**

  The APC IMP does not contain provision to address safety concerns raised by PHMSA as appropriate

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 30 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

In correspondence concerning this matter, please refer to **CPF 5-2008-0009M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

for

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc PHP-60 Compliance Registry
PHP-500 J Strawn (#118987)

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