



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

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NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 30, 2007

Ms. Marti Marek
Director, Engineering Staff
Southwest Gas Corporation
5421 Spring Mountain Road
Las Vegas, NV 89150

CPF 5-2007-0019M -

Dear Ms. Marek:

On August 14-17 and August 28-31, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected Southwest Gas Corporation and Paiute Pipeline Company's (SWG/Paiute) integrity management program in Las Vegas, Nevada. Both entities are covered under the one Integrity Management Program identified as Transmission Integrity Management Program (TRIMP).

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within the TRIMP plans or procedures, as described below:

1. High Consequence Area (HCA) Identification

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

(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to

individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish 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.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites. (i) Visible marking (*e.g.*, a sign); or (ii) The site is licensed or registered by a Federal, State, or local government agency; or (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 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.

§ 192.911 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.)

(a) An identification of all high consequence areas, in accordance with § 192.905.

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

- **Item 1A: § 192.905(a), § 192.903(2), (3), and (4), § 192.907(a) and § 192.911(a)**

The SWG/Paiute TRIMP and linked Operations Manual sections do not define all required process steps for identifying High Consequence Areas (HCA) in sufficient detail to support consistent implementation of the segment identification process. A considerable number of the HCA identification process steps that were described verbally are not documented in the current TRIMP and linked sections of the Operations Manual.

For example: The link from the TRIMP Plan to the “Main and Service Design” portion of Operations Manual does not provide process details (field measurements, use of field measurements, processing of data and use of maps, how often it is done, who has to do it).

- **Item 1B: § 192.905(b), § 192.903(4), and § 192.947(d)**

Decisions on which structures were considered identified sites are not documented. Field information on excluded structures is not recorded. Examples that were included in the “Main and Service Design” procedure and training on HCA identification provide incomplete guidance on what should be considered identified sites (e.g., “stadium” and “lake” examples). Consistent criteria for inclusion of specific types of areas (e.g., parking lots) are not documented.

- **Item 1C: § 192.905(b) and § 192.947(d)**

There is no documented program requirement to contact public officials to obtain information on potential identified sites. There are insufficient details provided for contacting public officials, such as a description of the method for establishing identified sites, to ensure that the process is repeatable and thorough.

- **Item 1D: § 192.905(c)**

The process for revising HCAs or identifying new HCAs is not defined in sufficient detail nor represented by procedures that describe how information on changes is obtained, how the information is communicated to personnel responsible for updating HCAs, how the information is used to update HCAs, how often this information is obtained and used, and who is responsible for obtaining it. Changes that are required to be addressed, but are not currently addressed by the TRIMP and implementing procedures include:

- a. Changes in pipeline maximum allowable operating pressure (MAOP),
- b. Pipeline modifications affecting piping diameter,
- c. Changes in the commodity transported in the pipeline,
- d. Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites,
- e. Change in the use of existing buildings (e.g., hotel or house converted to nursing home),
- f. Installation of new pipeline,
- g. Change in pipeline class location (e.g., class 2 to 3) or class location boundary,
- h. Pipeline reroutes
- i. Corrections to erroneous pipeline center line data.

As a specific example, there is no detailed process description or procedure that addresses how field personnel obtain and communicate information on new development along the pipeline that could lead to additional HCAs being defined.

2. **Baseline Assessment 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.)

(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;

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917).

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

- **Item 2A: § 192.921 (a)(4)**

A notification to PHMSA has not been filed for the use of guided wave or Long Range Ultra Sonic (LRUT) technology as an “other” technology for assessing the carrier pipe in casings. The basis for this failure to notify is that SWG/Paiute is using guided wave as a complementary tool to Pipeline Current Mapping (PCM) for these situations. However, PCM is not considered an effective tool to assess pipe within a casing. In fact, NACE RP 0502-2002, Table 2 indicates that additional considerations are needed for External Corrosion Direct Assessment (ECDA) tool selection for all cased piping. Therefore, use of guided wave is considered “new” technology and requires notification.

- **Item 2B: § 192.919 (c)**

The SWG/Paiute Baseline Assessment Plan (BAP) does not contain proposed assessment completion dates. As such, it is not possible to verify that assessments are completed on schedule and in accordance with the plan.

- **Item 2C: § 192.911(k)**

There are insufficient program procedures to describe the method by which the Operator keeps the BAP up-to-date with any newly arising information. Procedures to describe the process by which the Operator makes needed BAP in accordance with referenced Standard ASME B31.85-2001 do not include:

- i. Reasons for changes to the BAP,
- ii. Authority for approving changes,
- iii. Analysis of implications,
- iv. Communication of changes to affected parties.

3. Identify Threats, Data Integration, and Risk Assessment

§ 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.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

§ 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.

(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.

- **Item 3A: § 192.911(c) and § 192.917(a)**

The documented process for threat identification and evaluation does not specify timing of steps and the relation of threat evaluation steps to the conduct of baseline assessments.

The timing of steps in the current threat identification does not support the scheduling of integrity assessments in the BAP, because the specific required assessment methods would not be known until after completion of threat identification and evaluation (performed at the time of the assessment). Depending on the threats found to apply to a specific HCA, all of the following methods could be necessary: External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), and hydro-testing for manufacturing or construction defects or Low Frequency Electric Resistance Welded (LFERW) pipe.

- **Item 3B: § 192.911(c) and § 192.917(a)**

The screening criteria used in the evaluation of Stress corrosion Cracking (SCC) do not address near neutral SCC.

- **Item 3C: § 192.911(c) and § 192.917(a)**

The method of evaluation for interactive threats is not documented. No evaluation was performed or documented for those HCAs that had completed threat and baseline assessments. In addition, there is no adjustment made for these threats in the risk algorithm.

- **Item 3D: § 192.911(c) and § 192.917(c)**

The risk assessment process is not sufficiently detailed to identify how the risk assessment supports the objectives required by ASME B31.8S., Section 5.3. For example, the use of risk assessment to support preventive and mitigative measure evaluations or determination of assessment intervals is not addressed.

- **Item 3E: § 192.911(c) and § 192.917(c)**

The scoring in the population consequences index shows some logical inconsistencies. A single identified site would be given a higher score than any number of residences within the Potential Impact Radius (PIR) used to establish the HCA. The use of a calculated radius based on the equation in B31.8S (CFER Circle equation) as a variable is used without consideration of the number of residences or identified sites that exist within the circle.

- **Item 3F: § 192.911(c) and § 192.917(c)**

The risk assessment model does not adequately reflect leak/incident data. The current treatment is to associate the occurrence of a leak or incident with a specific pipeline segment. The applicability of the leak or incident to other HCAs is not considered in the current risk assessment process.

- **Item 3G: § 192.911(c) and § 192.917(c)**

The basis for the risk model weights for threat categories is not documented. The weight used for third party damage is considerably higher than the average for transmission pipelines. Although it may be suitable for the distribution portions of the SWG/Paiute system, whether the same weights should be applied to Paiute or certain transmission sections of the SWG/Paiute system (e.g., Southwest Gas Transmission Co.) have not been evaluated.

- **Item 3H: § 192.911(c) and § 192.917(c)**

Neither the TRIMP Plan nor the TRIMP Procedure adequately defines steps for revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments.

- **Item 3I: § 192.911(c) and § 192.917(c)**

The method for validation of the risk assessment results by SMEs is not documented in the TRIMP Plan or TRIMP Procedure.

4. **Direct Assessment (DA) 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.

(d) A direct assessment plan, if applicable, meeting the requirements of § 192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.

§ 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: § 192.911(d) and § 192.925(b)**

The TRIMP Procedure, Part 2, does not provide adequate procedural requirements sufficient to describe how the ECDA Plan is to be conducted in a repeatable consistent manner. This lack of program detail is noted through several of the PHMSA protocols for the Direct Assessment processes, including [D.01.a] [D.02.a] [D.02.b] [D.02.d] [D.03.a] [D.04.e] [D.04.g].

- **Item 4B: § 192.925(b)**

For the INA Road line, the pipeline is comprised of 4”, 6”, 8” and 12” diameter pipe; however the preassessment only discusses 4”, 6” and 12”. Three sections of 8” pipe were not mentioned. The final report only discusses 6” and 12” without an explanation of why all sizes were not addressed, or how SWG/Paiute determined preassessment information of the 4”, 6” and 12” lines was adequate and why the information in the final report on the 6” and 12” lines was sufficient.

- **Item 4C: § 192.925(b) and §192.947(d)**

The ECDA process for the INA Road does not fully integrate all leak data. The ECDA process considered a total of 35 leak maintenance reports (LMRs) for that segment. However, records provided indicated that only 8 were reviewed and utilized in pre-

assessment to capture coating data. No explanation of how the data was analyzed or why only 8 leak records were considered in the ECDA assessment.

- **Item 4D: § 192.925(b)(1) and §192.947(d)**

The NACE requirements for selecting and documenting the basis for indirect assessment tools are not described in SWG's TRIMP, Part 2, Table 9. The basis for deviation from the NACE indirect tool selection matrix has not been documented.

- **Item 4E: § 192.925(b)**

The SWG/Paiute TRIMP does not provide sufficient details within its procedures for ECDA Region definition based on indirect inspection tools selected, corrosion histories, and new data and information received from field surveys and indirect tool readings.

- **Item 4F: § 192.925(b)(1), § 192.925(b)(3)(i) and § 192.925(c)(5)(ii)**

The operator's Direct Assessment (DA) Plan does not provide criteria for performance of ECDA activities in each of the program phases, i.e., pre-assessment, indirect examination, and direct examination.

- **Item 4G: § 192.925(b)(2)**

TRIMP Procedure, Part 2 does not provide proper linkage to the abnormal operations procedure for cathodic protection (CP). The operator stated that the ECDA process stops when a low CP reading is identified until the CP can be brought within acceptance criteria and the abnormal operations procedural requirements are performed. No documentation of this approach exists within the TRIMP.

- **Item 4H: § 192.947(d)**

PHMSA inspection team review of the SWG/Paiute use of LRUT in the Paradise Pipeline Flamingo Wash location, determined that the indication locations did not match when performing LRUT from both directions. There was no documentation or process by which this discrepancy was resolved.

- **Item 4I: § 192.925(b)(3)**

A review of the Paradise pipeline ECDA Records indicated that the appropriate number of ECDA direct examinations was not performed. Only one "C-level" anomaly was excavated in region 1, only one "C" and no "no-indication" locations were excavated in Region 2. In region 1 in accordance with NACE §5.10 and §6.4 criteria, SWG/Paiute did not excavate an additional "B" and in region 2 SWG/Paiute did not excavate an additional "C" and a "no-indication" location.

- **Item 4J: § 192.925(b)(3)(ii)(b)**

SWG/Paiute does not have a documented root cause determination process that will enable them to determine if ECDA is or is not well-suited for assessing pipeline integrity.

- **Item 4K: § 192.925(b)**

TRIMP Procedure, Part 2, Section 9.18.1 states that an evaluation to assess the indirect inspection data and the results from the remaining strength evaluation and the root cause analyses must be performed.

TRIMP Procedure, Part 2, Section 9.18.2 states that the purpose of the evaluation is to critically assess the criteria used to categorize the need for repair, and to critically assess the criteria used to classify the severity of individual indications.

These sections are simply a restatement of NACE RP0502, Section 5.8 which requires the operator to conduct an In-Process Evaluation. The TRIMP wording does not describe how Paiute will actually carry out the evaluation, and Paiute was unable to provide documentation to demonstrate they performed the evaluation.

- **Item 4L: § 192.925(b)(3)(iv)**

A review of the Victorville, California ECDA data revealed that the Baseline Assessment Results report, the ECDA Severity Analysis Table produced by Mears (contractor), and the “Direct Examinations Dig Locations Listing” contain the indirect examination priorities for indications. These documents do not match in their priorities for the indirect inspections. There is no documentation of the process to establish the final dig list. It is also not clear how feedback is given to Mears to ensure that they make the proper priority call on indirect examination indications in the future.

- **Item 4M: § 192.925(b)(3)(iii), § 192.909, and § 192.911(k)**

Regarding establishing and implementing criteria and internal notification procedures for changes in the ECDA Plan (including those affecting severity classification, priority of direct examination, and the time frame for direct examination of indications), SWG/Paiute identified ECDA procedure (TRIMP Procedure, Part 2, Section 9.23) which addresses FEEDBACK AND CONTINUOUS IMPROVEMENT, as well as TRIMP Plan Section 16.5 which states “Company management and other appropriate personnel will be involved in the TRIMP communication process and support the integrity management program”, and “Changes to the integrity management program shall be communicated as necessary”. This wording is too general to require effective internal communication of changes in ECDA plan.

- **Item 4N: § 192.927(c)(1) and § 192.927(c)(5)(i)**

SWG/Paiute was unable to demonstrate a structured process for data gathering and integration to support performance of the ICDA methodology. The SWG/Paiute ICDA Plan repeats the requirements contained in the proposed NACE RP ICDA Methodology.

- **Item 4O: § 192.927(c)(5)(i).**

The PHMSA inspection team reviewed the Paradise Pipeline assessment and determined that critical angles were not identified although dig locations were identified and excavated.

5. Remediation

§ 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.

(e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.

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

(a) *General requirements...* 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...

...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.

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule

- **Item 5A: § 192.911(e) and § 192.933(b)**

The SWG/Paiute TRIMP does not provide information on where the date when the "Discovery of Condition" as defined in 192.933(b) is to be documented.

- **Item 5B: § 192.911(e) and § 192.933(d)(1)**

The SWG/Paiute Remediation Design procedure does not contain provisions to require a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions.

- **Item 5C: § 192.911(e) and § 192.933(d)(3)**

The SWG/Paiute TRIMP does not contain program requirements for the recording and monitoring of anomalies that are classified as "monitored conditions" during subsequent risk or integrity assessments for any change in their status that would require remediation.

Item 5D: § 192.911(e), § 192.933(a), § 192.933(c), and § 192.947(f)

There are no program requirements that specify how and by whom technical justifications for schedule change contingencies are to be developed and documented.

6. **Recordkeeping**

§ 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.

(j) Record keeping provisions meeting the requirements of § 192.947.

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with § 192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with § 192.917;

(c) A written baseline assessment plan in accordance with § 192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation

and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with § 192.915;

(f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule;

(g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in § 192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

- **Item 6A: § 192.911(j) and § 192.947**

The SWG/Paiute TRIMP and implementing procedures do not have instructions on developing records and archiving them appropriately. As an example, there is no record of decisions made for identified site surveys and the basis for inclusion or exclusion.

7. **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.

(b) **Notification.** An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

§ 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 7A: § 192.909(a), § 192.909(b) and § 192.911(k)**

The SWG/Paiute Management of Change (MOC) process is fragmented and does not contain sufficient detail to ensure that changes are thoroughly evaluated, tracked and reviewed and that all required aspects of the changes are documented. This issue includes changes to the IMP, documents developed by the IMP, procedure changes, and physical system changes, such as pipeline replacements, MOP revisions where uprating to a value greater than 20% SMYS is being considered.

8. Quality Assurance

§ 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.

- **Item 8A: § 192.911(l)**

There is a lack of program procedures for the process used to ensure corrective measures are documented and monitored for effectiveness. There were insufficient instructions on how to document identified issues, on the performance of a root cause determination, assessment of generic implications, prescription of actions to prevent recurrence, and there was no method to track and monitor the effectiveness of such actions.

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 5-2007-0019M** 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 P. Katchmar

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