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 4, 2007

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Mr. Randy Barnard
VP Operations and Gas Control
Williams Gas Pipeline
2800 Post Oak Blvd
P.O. Box 1396
Houston, TX 77056

CPF 5-2007-1004M

Dear Mr. Barnard:

On March 13-17 and March 27–30, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected Williams Gas Pipeline's (WGP's) procedures for the Integrity Management Program (IMP) in Salt Lake City, Utah.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within WGP's plan or procedure and are described below. Probable non-violations resulting from that same inspection were already sent to you in our letter, CPF No. 5-2007-1001, dated January 29, 2007.

1. **Identification of High Consequence Areas**

   §192.911 What are the elements of an integrity management program?
   (a) An identification of all high consequence areas, in accordance with §192.905.
   (p) A process for identification and assessment of newly-identified high consequence areas. (See §192.905 and §192.921.)

   §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. (See appendix E.I. for guidance on identifying high consequence areas.)
(b) 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.
(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.

- **Item 1A: §192.911(a) and §192.905(a)**

Williams Gas Pipeline's procedure 10.09.01.10 and IMP Overview Chapter 4 define Methods 1 and 2 consistent with rule requirements. However, these documents do not provide detailed information on how these HCA identification methods are implemented. The procedure needs amending to include Process steps, responsibilities, data inputs and outputs, and documentation requirements.

- **Item 1B: §192.911(a) and §192.905(a)**

Procedure 10.09.01.10, Section 10.1.5 states that all WGP HCA locations shall be permanently recorded and that the recorded information "may" include the method used to identify HCA. The procedure needs amending to reflect the rule requirement this information "must" be documented.

- **Item 1C: §192.911(a) and §192.905(a)**

Procedure 10.09.01.10, Section 10.1.6 is inadequate as it indicates system maps will be maintained and updated with aerial photography for identifying HCAs without specifying what frequency the aerial photography is to be updated.

- **Item 1D: §192.911(a) and §192.905(a)**

Instructions provided to the field (e.g., Appendix A of IMP Overview Chapter 4) do not provide data accuracy instructions on how to measure and locate piping and adjacent structure/identified site locations.

- **Item 1E: §192.911(a) and §192.905(b)**

WGP does not have a formalized procedure or process for how facility use data is collected during routine operation and maintenance activities to document if sites meet the identified site criteria.

- **Item 1F: §192.911(a), §192.911(p) and §192.905(c)**

WGP's integrity management program does not include documented processes for how new information indicating a pipeline segment impacts a high consequence area is identified and integrated with the integrity management program. These documented processes do not include activity steps, responsibilities, data inputs and outputs, and documentation requirements.

2. **Baseline Assessment Plan**

§192.911 What are the elements of an integrity management program?
(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

§192.921(a)(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.

§192.921(f) Newly identified areas. When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

- **Item 2A: §192.911(b) and §192.921(a)(4)**

WGP's procedures for notifying OPS, State, or local pipeline safety authorities of the use of "other technology" are not included in their integrity management plan documentation.

- **Item 2B: §192.911(b) and §192.921(f)**

For newly identified HCAs or newly installed pipe that is covered by this subpart and impacts an HCA, WGP does not have a procedural requirement to complete a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified.

3. **Identify Threats, Data Integration, and Risk Assessment**

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

(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 as follows:
(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.

§192.917(e)(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.

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

WGP threat identification process has not provided sufficient technical justification for the elimination of the SCC threat.

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

It is not apparent interactive threats have been considered in the WGP threat identification process. SMEs have ability to recognize interactive threats and adjust risk based on their knowledge of the threats, but WGP has not provided guidance in procedures for this activity. The inspection team recognized that the Threat Identification Checklists have the potential to provide for consideration of interacting threats.

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

Procedure 10.25.01, Section 4.0 provides high level requirements for data collection and integration. Integrity Sheet 1400.13-101A shows data integration for an ECDA project. However, procedures are not in place to provide instructions on how data is to be included on the Integrity Sheet. Documented procedures that include required activity steps, responsibilities, data inputs and outputs, and documentation requirements have not been established.

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

Processes have not been defined for the responsibilities for data collection or how the data sets are assembled, how accuracy is verified, how the data is maintained, or defining the sets of data that must be collected. WGP has the intent and is in the process of developing a GIS that they will use to integrate data comprehensively by the end of 2006.

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

Data sources listed in ASME B31.8S Table 2 are not specified as required data sets in the WGP risk assessment process.

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

WGP procedures for data gathering and integration are inadequate as they do not include processes for verifying data quality as required by ASME/ANSI B31.8S Section 4. Procedures do not require that conservative assumptions be applied if data is missing or suspect. The procedures do not specify additional inspections or field data collection efforts must be initiated for missing/suspect data.

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

Procedure 10.25.01, Section 9.1.1 specifies that risk assessment validation activities are to be conducted each calendar year. The procedures are inadequate as a specific performance date or link to an activity milestone is not defined in IMP procedures to trigger the activity. Additionally, procedures have not been established describing how SMEs perform the validation process to ensure risk results are logical and consistent with the operator's and other industry experience.

- **Item 3H: §192.911(c) and §192.917(e)(5)**

WGP's procedures do not describe the process by which all covered and non-covered segments with similar environmental characteristics and coating will be evaluated when corrosion is discovered on a covered segment that can adversely affect the integrity of the pipeline.

4. **External Corrosion Indirect Assessment**

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

- **Item 4A: §192.911(d) and §192.925(b)(1)(i)**

The ECDA procedure 20.19.01.02 does not include the 192.925 requirement initial ECDA assessments include more restrictive criteria for the pre-assessment and that this be documented.

- **Item 4B: §192.911(d) and 192.925(b)(2)**

There is no reference to industry standards for conducting and analyzing ECDA indirect inspection results for each of the selected tools. The physical spacing of each tool is not referenced in the ECDA procedure.

- **Item 4C: §192.911(d) and 192.925(b)(2)**

The NACE RP requires that conflicting results be documented and resolved. The ECDA procedure does not address this issue nor was there any documentation that this was considered or what actions are taken if this occurs.

- **Item 4D: §192.911(d) and 192.925(b)(2)(i)**

The ECDA procedure 20.19.01.02 does not include the 192.925 requirement that initial ECDA assessments include more restrictive criteria for the indirect inspection and that this be documented.

- **Item 4E: §192.911(d) and §192.925(b)(3)**

The ECDA procedure does not follow the NACE RP for all required excavations.

- **Item 4F: §192.911(d) and §192.925(b)(3)**

The ECDA procedure 20.19.01.02 section 6.1.2.3.1.1 requires that if significant external corrosion is discovered it must be evaluated by a root cause analysis and consideration of another method of assessment. There is no definition of the term "significant".

- **Item 4G: §192.911(d) and §192.925(b)(3)**

The WGP ECDA procedure does not require an evaluation of the indirect inspection data using the results of the remaining strength calculations and root cause analysis as required by NACE RP 0502-2002, section 5.

- **Item 4H: §192.911(d) and §192.925(b)(3)**

The ECDA procedure does not address the need to use other assessment methods if defects other than EC are discovered during an ECDA.

- **Item 4I: §192.911(d) and §192.925(b)(3)(i)**

The ECDA procedure 20.19.01.02 does not include the 192.925 requirement that initial ECDA assessments include more restrictive criteria for direct examinations and that this be documented.

5. Remediation

§192.911 What are the elements of an integrity management program?
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

§192.933(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.

§192.933(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.

§192.933(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. An operator must notify OPS in accordance with §192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. 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.

§192.933(d) Special requirements for scheduling remediation.
1. Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:
i. A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991); AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)); or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in Appendix A to Part 192.
ii. A dent that has any indication of metal loss, cracking or a stress riser.
iii. An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action. (1)(ii) A dent that has any indication of metal loss, cracking or a stress riser.
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: §192.911(e) and §192.933(a)**

The ECDA procedure for determining remaining strength does not require that the operating pressure be reduced to 80% or less of the operating pressure if there is an immediate repair per 192.933.

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

Per Procedure 70.17.01.07, Figure 7, a pressure reduction for an immediate repair condition can be made using either a reduction to 80% of operating pressure or based on 0.9 x Pburst as calculated by RSTRENG. A pressure reduction must be taken based upon Psafe as calculated by B31G or RSTRENG. WGP procedures do not reflect this requirement.

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

WGP's repair procedure does not meet code requirements for using Type B sleeves for repairs involving anomalies greater than 80% wall loss.

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

Per Section 8.1.4 of Procedure 70.17.01.07, "Pigging – Inline Inspection" a separate discovery date is established for a geometry and MFL tool run when performed 120 days or more apart; however, the analysis shall still be a joint analysis. This is inconsistent with rule requirements. If any anomalies are discovered from the geometry tool assessment results, a one year repair condition may not be addressed in accordance with IM rule repair schedule requirements.

- **Item 5E: §192.911(e) and §192.933(c)**

Per Section 8.2.3 of Procedure 70.17.01.07, scheduled anomalies will be excavated within 365 days. Figure 4 of ASME B31.8S provides a time frame for addressing scheduled anomalies that have a Pf/MAOP > 1.1. In some cases the time frames are less than 365 days. WGP's procedures do not require examination or remediation in the appropriate timeframe. Per Section 192.933(c), "An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation." Section 8.2.3 of Procedure 70.17.01.07 does not provide sufficient detail or guidance for the development of a prioritized schedule.

- **Item 5F: §192.911(e) and §192.933(c)**

WGP's procedures do not meet the provisions of ASME B31.8S, Figure 4 for scheduling anomalies for examination or remediation.

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

In Section 8.2.3 of Procedure 70.17.01.07, WGP states: "All dents with metal loss (where the metal loss is believed to be corrosion) shall be considered a higher priority than other scheduled anomalies and shall be excavated first." Per the IM rule 192.933(d)(ii): "A dent that has an indication of metal loss, cracking, or a stress riser" is an immediate repair condition.

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

Procedure 20.19.01.02 does not address "monitored" conditions as required by the Gas IMP rule for external corrosion direct assessment.

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

WGP procedures allow a priority I coating indication to wait up to one year before excavation which is inconsistent with PHMSA guidance. All required digs must be completed within 6 months after the indirect inspection surveys.

6. **Preventive and Mitigative Measures**

§192.911 What are the elements of an integrity management program?
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

§192.937(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 6A: §192.911(h) and §192.937(a)**

WGP's ECDA procedure does not require that mitigative actions be completed and documented.

- **Item 6B: §192.911(h) and §192.937(a)**

Section 9.0 of procedure 10.25.01.02 describes the process for identifying additional preventive and mitigative measures. The procedure does not delineate how risk analysis will be used in the decision making process.

- **Item 6C: §192.911(h) and §192.937(a)**

Per section 9.0 of WGP procedure 10.25.01.02, decisions regarding preventive and mitigative measures are made during the annual SME review of risk assessment results. This procedure does not address the process of how the SMEs shall identify, evaluate, and recommend additional preventive and mitigative measures. In addition, this procedure does not delineate how the risk model will be used in the decision making process.

7. **Performance Measures**

§192.911 What are the elements of an integrity management program?
(i) A performance plan as outlined in ASME/ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of §192.945.

§192.945(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 7A: §192.911(i) and §192.945(a)**

The WGP procedure 10.24.01.02 does not provide sufficient detail for the responsibility of who should collect information for submittal. [I.01.a]

8. **Management of Change**

§192.911 What are the elements of an integrity management program?
(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

§192.909(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.

ASME B31.8S-2001, Section 11
(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural and organizational changes to the system whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:
(1) Reason for change
(2) Authority for approving changes
(3) Analysis of implications
(4) Acquisition of required work permits
(5) Documentation
(6) Communication of change to affected parties
(7) Time limitations
(8) Qualification of staff

(b) The operator shall recognize that system changes can require changes in the integrity management program and conversely, results from the program can cause system changes. The following are examples that are gas pipeline specific but are by no means all inclusive.

- **Item 8A: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

WGP has requirements for an annual review to keep 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. A specific performance date or link to an activity milestone must be defined in IMP procedures for the performance of the annual reviews.

- **Item 8B: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

WGP IMP procedures do not address reasons for changes to the BAP, authority for approving the change, analysis of implications of the change, or communication of the change to affected parties.

- **Item 8C: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

WGP procedure 10.25.01, Section 9.1.1 requires an annual update of the risk assessment but does not provide a process or define responsibilities for ensuring new information is incorporated in a timely manner or to establish an interface with the management of change process to ensure changes are appropriately reflected in risk analysis data. Additionally a specific performance date or link to an activity milestone is not defined in IMP procedures for the performance of the annual update.

- **Item 8D: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

Procedure 10.29.01.02 addresses the MOC process; however, the process does not address procedural and organizational changes.

- **Item 8E: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

Not all of the requirements of ASME B31.8S, Section 11 are addressed by WGP's Management of Change procedures.

- **Item 8F: §192.911(k) and ASME B31.8S-2001, Section 11(b)**

Some important system changes were not reported to the IMP team that could have affected pipeline integrity.

- **Item 8G: §192.911(k) and §192.909(b)**

WGP's Integrity Management Procedures do not require notification of OPS or the State or local pipeline safety authorities of significant changes to the program, program implementation, or schedules. Additionally, the definition of what constitutes a significant change has not been identified in IMP procedures. It was noted that WGP did have a change log that listed changes that have occurred and the log included limited examples of what are considered to be significant changes.

9. Quality Assurance

§192.911 What are the elements of an integrity management program?
(l) A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

§192.907(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.

ASME B31.8S-2001, Section 12.2, Quality Management Control.
(b) Specifically, activities that should be included in the quality control program are as follows:
(2) The responsibilities and authorities under this program shall be clearly and formally defined.

(3) Results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.
(4) The people involved in the integrity management program shall be competent, aware of the program and all of its activities and shall be properly trained to execute the activities within the program. Documentation of such competence, awareness and qualification, and the processes for their achievement, shall be part of the quality control plan.
(7) Corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.
(c) When an operator chooses to use outside resources to conduct any process, for example pigging, that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program.

§192.915(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.

§192.915(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.

- **Item 9A: §192.911(l) and ASME B31.8S-2001, section 12.2(b)(2)**

Chapter 2 of the WGP Integrity Management Program Overview delineates responsibilities; however, these responsibilities do not align with those delineated in individual WGP O&M procedures applicable to the IM Program.

- **Item 9B: §192.911(l) and ASME B31.8S-2001, section 12.2(b)(3)**

The WGP O&M manual has no procedures describing how internal Integrity Management reviews are conducted or documented. Requirements for the conduct of annual reviews should be tied to a specific calendar timeframe or event milestone.

- **Item 9C: §192.911(l) and ASME B31.8S-2001, section 12.2(b)(7)**

WGP procedures do not document or track corrective actions identified by audits of the Integrity Management Program.

- **Item 9D: §192.911(l) and ASME B31.8S-2001, section 12.2(c)**

WGP needs to identify the minimum qualification requirements for vendor and WGP personnel involved in the control of the outsourced resources affecting the quality of the Integrity Management Program. In addition, to identifying the minimum qualification requirements, WGP needs to ensure that personnel performing IM activities meet those requirements.

- **Item 9E: §192.911(l), ASME B31.8S-2001, section 12.2(b)(4) and §192.915(a)**

Chapter 14 of the Integrity Management Overview does not provide minimum qualification requirements for supervisory personnel.

- **Item 9F: §192.911(l), ASME B31.8S-2001, section 12.2(b)(4) and §192.915(b)**

The Inline Inspection Specifications requires that vendor personnel meet industry qualification standards; however, WGP's procedures do not require that the qualifications of vendor personnel be verified.

- **Item 9G: §192.907(b)**

Although WGP has verbally stated they will: 1) incorporate into their IM plan or procedures they will adopt all "should" statements; 2) identify an equivalent alternative method for accomplishing the same objective is justified and implemented; or 3) document a justification in their plan or procedures demonstrates the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O; however, these requirements are not reflected in either WGP plan or procedures.

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 5-2007-1004M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

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

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

cc: PHP-60 Compliance Registry
PHP-500 J. Gilliam (#116651)