



Wild Goose Storage, LLC
A Rockpoint Gas Storage Company

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November 12, 2025

Terence Eng, P.E.
Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
505 Van Ness Avenue, 2nd Floor
San Francisco, CA 94102-3298
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VIA ELECTRONIC MAIL

**RE: General Order 112-F Transmission Integrity Management Program (TIMP)
Inspection of Wild Goose Storage**

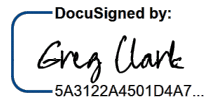
Dear Mr. Eng:

Wild Goose Storage, LLC (WGS) submits this written response to the Safety and Enforcement Division (SED) of the California Public Utilities Commission (Commission). On behalf of the SED, Paul Penney and Kai Cheung conducted a General Order 112-F inspection of WGS's TIMP from May 19-23, 2025, and July 18, 2025. The inspection findings identified by SED were provided to WGS on October 13, 2025. WGS addresses the inspection findings as noted by SED in the "Post-Inspection Written Findings" in the following enclosed documents:

- **Attachment #1** – WGS Responses to "Post-Inspection Written Findings"
- **Attachment #2** – Excerpt from WGS Operations and Maintenance Manual, consisting of section 3.13 which addresses repair criteria in non-covered segments
- **Attachment #3** – Excerpt from WGS Operations and Maintenance Manual section 8.3 highlighting revisions to address reassessments when using the Engineering Critical Assessment method
- **Attachment #4** – Excerpt from WGS Integrity Management Program Manual, consisting of section 5.5 which addresses repair procedures for covered segments
- **Attachment #5** – Excerpt from WGS Operations and Maintenance Manual section 3.13 highlighting revisions to address welded patches

If you have any questions, or require more information, please contact me at **greg.clark@rockpointgs.com** or at (209) 368-9277.

Sincerely,

DocuSigned by:

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Gregory N. Clark
Senior Compliance Manager

Enclosures

cc: C. Almengor (claudia.almengor@cpuc.ca.gov)
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A. Anderson, S. Aycock, G. Bozarth (via e-mail)

Attachment #1



WGS Responses to “Post-Inspection Written Findings”



WGS Responses to Post-Inspection Written Preliminary Findings

Dates of Inspection: May 19-23, 2025 & July 18, 2025

Operator: WILD GOOSE STORAGE LLC

Operator ID: 31287 (primary)

Inspection Systems: The entire transmission system

Assets (Unit IDs) with results in this report: All Transmission Assets in WGS System

System Type: GT

Inspection Name: (2025) Wild Goose Storage TIMP Audit

Lead Inspector: Paul Penney

Operator Representative: Greg Clark, et all

Unsatisfactory Results

Assessment and Repair : In-Line Inspection (Smart Pigs) (AR.IL)

Unsat #1:

Question Title, ID Validation of ILI Results, AR.IL.ILIVALIDATE.R

Question 9. Do records demonstrate that the operator has validated ILI assessment results per their process?

References 192.947 (192.921(a)(1), 192.493)

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary The WGS TIMP procedure incorporates API 1163, which is incorporated by reference into 192.493.

WGS provided the dig results from "Integrity Inspections" (A contractor used to dig the anomaly) per their process identified in AR.IL.ILIVALIDATE.P in this IA. The dig report was provided in WGS response to DR09.

SED reviewed the report from Integrity Inspections. It is unclear from this report how the inspection results were used to validate the ILI inspection done in 2021. According to WGS process, API Standard 1163, section 8.2, Figure 6 is used to validate inspection results. Figure 6 is a flow chart that provides different levels of verification to follow when validating the inspection results. However, WGS provided no records showing how Figure 6 was used to validate the results.

192.947(d) states:



(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;

WGS is in violation of 192.947(d) for failure to provide records showing how WGS followed its process in validating the ILI inspection results from 2021 as requested in DR09.

WGS Response WGS is focused on continuous improvement of TIMP recordkeeping and shall endeavor to properly document ILI assessment validation results.

Integrity Management : Preventive and Mitigative Measures (IM.PM)

Unsat #2:

Question Title, ID P&M Measures - General Requirements, IM.PM.PMMGENERAL.R

Question 2. Do records demonstrate that additional measures have been identified and implemented (or scheduled) beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA?

References 192.947 (192.935(a), 192.935(f))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS states in its response to DR34: *"No additional measures have been identified and implemented beyond what has already been provided for part 192."*

Part 192.935(a) requires:

An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area (emphasis added). Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

WGS is in violation of 192.935(a) for not taking additional measures as required by 192.935(a) above, and base those measures on the risk analysis required by 192.917.

WGS Response WGS procedures for preventive and mitigative measures are located in Section 6 of the WGS TIMP. This procedure, in accordance with 192.935(a)(1)(ii), describes the enhanced preventive or additional mitigative measures that WGS would employ to protect high consequence areas and to enhance public safety should additional measures be deemed necessary by the results of the WGS risk assessment. However, WGS risk assessments have not identified the need to implement additional measures (e.g., WGS has had no incidents to correct the root cause, WGS has not lost records where hydrotests need to be conducted, WGS has not conducted pipeline replacements).



Concerns

Assessment and Repair : Repair Criteria (O&M) (AR.RCOM)

Concern #1:

Question Title, ID Repair Criteria in Non-Covered Segments, AR.RCOM.NONCOVERED.P

Question 1. Does the integrity assessment and maintenance processes include adequate criteria for determining the need for, and timeliness of, pipeline defect repairs in non-covered segments?

References 192.485(a) (192.485(b), 192.485(c), 192.703(b), 192.710, 192.711, 192.713, 192.714)

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary SED reviewed the WGS TIMP and O&M Procedures. WGS covers the above referenced codes in sections 2.2.4 in the TIMP and O&M procedures, Section 3.13.

The WGS TIMP and O&M plans currently do not incorporate language from PHMSA Amendment 192-125, effective July 1, 2020. The Amendment includes many new requirements, including 192.710 (Assessments in non-covered segments) and 192.711 (General requirements for repair procedures in covered and non-covered segments).

WGS needs to update the TIMP and/or O&M plans to include the two code sections referenced above that are not already incorporated.

WGS Response WGS O&M Procedures section 8.2 addresses assessments in non-covered segments, including the requirements prescribed by 192.710. WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.

Assessment and Repair : In-Line Inspection (Smart Pigs) (AR.IL)

Concern #2:

Question Title, ID ILI Specifications, AR.IL.ILISPECS.R

Question 5. Do records demonstrate that the ILI specifications were complete and adequate?

References 192.947(g) (192.933(b), 192.493)

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary In WGS's response to DR07, WGS provided a specification sheet from ENDURO for their response. This specification sheet does not include records to demonstrate that the ILI specifications were complete and adequate. The IA question references 192.493, which in turn references API 1163.



See API 1163, sections 5 (In-line inspection System Selection), 6 (Qualification of Performance Specifications), and 7 (System Operational Verification) for details. These chapters provide details on what to include in the WGS ILI specifications.

WGS Response WGS is focused on continuous improvement of TIMP recordkeeping and shall endeavor to properly document ILI specifications.

Assessment and Repair : Predicted Failure Pressure (AR.PFP)

Concern #3:

Question Title, ID Anomaly Analysis - Records Process, AR.PFP.ANOMALYREASSESS.P

Question 8. Do procedures detail the reassessment of anomalies when an operator used an Engineering Critical Assessment method?

References 192.605 (192.712(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS did not provide a procedure to demonstrate compliance with 192.712(h) related to engineering critical assessment.

192.712(h) states in part:

(h) Reassessments. If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

WGS must update its procedures(s) to comply with 192.712(h) related to reassessment of anomalies that have had an engineering critical assessment.

WGS Response WGS has updated its O&M Procedures section 8.3 to address reassessments when using the Engineering Critical Assessment method. Please see Attachment #3.

Assessment and Repair : Repair Criteria (HCA) (AR.RCHCA)

Concern #4:

Question Title, ID General Requirements, AR.RCHCA.GENERAL.P

Question 1. Do the repair procedures detail what actions must be taken to address integrity issues?



References 192.907(a) (192.933(a))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS incorporated wording from 192.933(d) into its TIMP procedures. However, part of the wording in the referenced 192.933(d) is missing. For example, WGS only referenced three monitored conditions listed on page 31 of the WGS TIMP. However, the latest update to 192.933(d)(3) includes six categories for monitored conditions.

WGS must update the language for all categories, including immediate, one-year, and monitored. This will allow WGS to properly categorize the defects and identify timeframes for repair. With regard to repair procedures, WGS covers this requirement in the O&M Plan, Section 3.13 (Repair Procedures and Documentation for Gas Transmission Pipelines).

WGS Response WGS has updated its TIMP procedures section 5.5 to address repair procedures taken to address integrity issues. Please see Attachment #4.

Concern #5:

Question Title, ID Prioritized Scheduling, AR.RCHCA.SCHEDULE.P

Question 7. Do the repair procedures discuss remediating conditions according to a prioritization schedule in covered segments?

References 192.907(a) (192.933(c))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS TIMP Plan has not been updated with the latest revision to B31.8S, identified in 192.7. B31.8S is the 2018 version.

WGS needs to update its TIMP Plan with the changes to 192.933(c), which includes the latest version of B31.8S incorporated by reference: B31.8S-2018 (schedule in ASME B31.8S, section 7, Figure 7.2.1-1). See Section 5.5.1 of the TIMP plan, which references the 2004 version of B31.8S.

WGS Response WGS has updated references to ASME B31.8S throughout its TIMP procedures to reference the 2018 version.

Concern #6:

Question Title, ID Immediate Repair Conditions, AR.RCHCA.IMMEDIATE.P

Question 9. Do the repair procedures cover all of the elements for making immediate repairs in covered segments?

References 192.907 (192.933(d)(1))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS has not incorporated the latest changes in Part 192 for the “immediate repair condition” category into its TIMP Plan for covered segments. An immediate repair condition requires an operator to immediately schedule a repair unless the operator lowers pressure on the pipeline or shuts down the pipeline until the operator completes repair of the conditions.

For example, 192.933(d)(iv) requires remediation for metal loss preferentially affecting a detected longitudinal seam—a requirement missing from WGS’s TIMP plan.



Furthermore, crack or crack-like anomalies meeting certain criteria are now categorized as immediate repair conditions; however, crack or crack-like anomalies are not specified as an immediate repair condition in WGS's TIMP Plan.

WGS must update the TIMP Plan with the latest changes for the immediate category in Part 192.

WGS Response WGS has updated its TIMP procedures section 5.5 to address repair procedures taken to address integrity issues. Please see Attachment #4.

Concern #7:

Question Title, ID One-Year Conditions, AR.RCHCA.ONEYEAR.P

Question 11. Do the repair procedures cover all of the elements for making repairs in covered segments for One-year conditions?

References 192.907 (192.933(d)(2))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS has not incorporated the latest changes in Part 192 for the one-year category into its TIMP Plan. The one-year category includes anomalies or defects that must be repaired within one year of discovery.

WGS needs to update its TIMP Plan with the latest changes for the one-year category. There are multiple changes that need to be added. For example, section 5.5.3 (pg. 30) of the TIMP plan lists seven types of one-year conditions, none of which include cracks as required by 192.933(d)(2). All seven required categories are defined in 192.933(d)(2) and must be included in the WGS TIMP plan.

WGS Response WGS has updated its TIMP procedures section 5.5 to address repair procedures taken to address integrity issues. Please see Attachment #4.

Concern #8:

Question Title, ID Monitored Conditions, AR.RCHCA.MONITOR.P

Question 13. Do the repair procedures require the operator to record and monitor conditions that meet monitoring criteria in covered segments?

References 192.907 (192.933(d)(3))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary There are six categories in the latest revision to Part 192 for monitored conditions. The WGS TIMP Plan has three categories for the monitored category.

WGS needs to update the TIMP Plan with the latest additions for the monitored category in Part 192.922(d)(3).

WGS Response WGS has updated its TIMP procedures section 5.5 to address repair procedures taken to address integrity issues. Please see Attachment #4.



Concern #9:

Question Title, ID Repair Procedures (Weld Patch), AR.RCHCA.CRITERIAWELD.P

Question 22. Do the repair procedures prohibit the operator from using welded patches?

References 192.605(b)(1) (192.711(c))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary The requirement in 192.711(c) to not use welded patches—with the exception in 192.717(b)(3)—is not in WGS's O&M Plan, Section 3.13 or any other section. WGS must include wording that disallows welded patches in its O&M plan.

WGS Response WGS has updated its O&M Procedures section 3.13 to specifically include wording that disallows welded patches. Please see Attachment #5.

Assessment and Repair : Repair Criteria (Non-HCA) (AR.RCNONHCA)

Concern #10:

Question Title, ID Prioritized Scheduling, AR.RCNONHCA.SCHEDULE.P

Question 3. Do the repair procedures discuss remediating conditions according to a prioritization schedule in non-covered segments?

References 192.605 (192.714(c), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary The current requirement in 192.714(c) is to include a prioritized schedule. The TIMP Plan does not include a reference to this code requirement (192.714(c)). WGS needs to update its TIMP Plan to include this requirement.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments including remediating conditions according to a prioritized schedule. Please see Attachment #2.

Concern #11:

Question Title, ID Immediate Repairs, AR.RCNONHCA.IMMEDIATE.P

Question 5. Do the repair procedures cover all of the elements for making immediate repairs in non-covered segments?

References 192.605 (192.714(d)(1), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)



Issue Summary WGS does not have repair procedures that cover all of the elements for making immediate repairs in non-covered segments. Neither WGS's O&M nor TIMP Plan include references to 192.714, which has the requirements for non-HCA repairs for different categories such as "immediate repair conditions". WGS needs to update its O&M Plan or TIMP Plan to include this requirement for an "Immediate" repair in non-covered segments.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.

Concern #12:

Question Title, ID Two-Year Conditions, AR.RCNONHCA.TWOYEAR.P

Question 7. Do the repair procedures cover all of the elements for making repairs in non covered segments for Two-year conditions?

References 192.605 (192.714(d)(2), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS does not have repair procedures that cover all of the elements for making repairs in non-covered segments for Two-year conditions. WGS's TIMP Plan does not reference 192.714, which has the requirements for non-HCA repairs for the "two-year conditions" category. WGS needs to update its TIMP Plan to include the requirement for the "two-year conditions" category.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.

Concern #13:

Question Title, ID Monitored Conditions, AR.RCNONHCA.MONITOR.P

Question 9. Do the repair procedures require the operator to record and monitor conditions that meet monitoring criteria in non covered segments?

References 192.605 (192.714(d)(3), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS does not have repair procedures that require the operator to record and monitor conditions that meet monitoring criteria in non covered segments. WGS's TIMP plan does not reference 192.714, which has the requirements for non-HCA repairs for different categories such as "Monitored Conditions". Also, there is nothing in the TIMP plan that requires WGS to record and monitor conditions that meet the monitoring criteria. WGS needs to update its TIMP Plan to include monitored conditions in non-HCAs.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.



Concern #14:

Question Title, ID Temporary Pressure Reduction, AR.RCNONHCA.PRESSUREREDUC.P

Question 11. Do the repair procedures require a temporary pressure reduction for making repairs in non-covered segments?

References 192.605 (192.714(e), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS does have repair procedures that require a temporary pressure reduction for making repairs in non-covered segments. WGS's TIMP plan does not reference 192.714(e), which lists the requirements for non-HCA temporary pressure reductions. There are three options in 192.714(e) for calculating the required pressure reduction. WGS should include all three options in the WGS TIMP plan.

192.714(h) states:

(e) *Temporary pressure reduction.*

(1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.

Concern #15:

Question Title, ID Other Conditions, AR.RCNONHCA.OTHER.P

Question 13. Do the repair procedures require the operator to take appropriate remedial action for other conditions that could affect safe operations in non-covered segments?

References 192.605 (192.714(f), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary There is no reference in the WGS TIMP Plan or the O&M Plan for 192.714(f) for "other conditions". 192.714(f) states:

(f) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

WGS needs procedures to address the requirements of 192.714 and the different categories of defects not included in the TIMP Plan for non-HCAs, including the "other conditions" category.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments. Please see Attachment #2.



Concern #16:

Question Title, ID Crack Defects, AR.RCNONHCA.CRACK.P

Question 15. Do the repair procedures require the operator to perform direct examinations of known locations of cracks or crack-like defects?

References 192.605 (192.714(g), 192.714(h))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS's plans (TIMP and/or O&M) do not include repair procedures that require the operator to perform direct examinations of known locations of cracks or crack-like defects. WGS needs to address the requirement of section 192.714(g), which states:

(g) In situ direct examination of crack defects. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

WGS Response WGS has updated its O&M Procedures section 3.13 to address repair criteria in non-covered segments including in situ direct examination of crack defects. Please see Attachment #2.

Assessment and Repair : Repair Methods and Practices (AR.RMP)

Concern #17:

Question Title, ID Prevention of Accidental Ignition, AR.RMP.IGNITION.R

Question 4. Do records indicate adequate steps were taken by the operator to prevent accidental ignition prior to performing work?

References 192.751(a) (192.751(b), 192.751(c))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS states in response to DR19 that records are not required per its O&M procedure.

However, 192.603(b) requires: *"Each operator shall keep records necessary to administer the procedures established under § 192.605."* These procedures include O&M and Emergency Plan Procedures.

192.751 has specific requirements related to prevention of accidental ignition. WGS needs to develop a process to ensure the requirements of 192.751 are met. For example, a form could be used.

WGS Response WGS shall consider SED's recommendation regarding records for prevention of accidental ignition prior to performing work.



Concern #18:

Question Title, ID Transmission Lines General Requirements for Repair Procedures, AR.RMP.REPAIRREQT.P

Question 9. Does the repair process capture the requirements of 192.711 for transmission lines?

References 192.605(b)(1) (192.711(a), 192.711(b), 192.711(c), 192.717(b)(3))

Assets Covered All Transmission Assets in WGS (AllTrans)

Issue Summary WGS discusses the repair process in its O&M Plan, Section 3.13. Welded patches are not explicitly disallowed as noted in 192.711(c). In other words, WGS should state in its O&M Plan, Section 3.13 that welded patches are not allowed with the exception noted.

192.711(c) states:

Except as provided in [§ 192.717\(b\)\(3\)](#), no operator may use a welded patch as a means of repair.

WGS Response WGS has updated its O&M Procedures section 3.13 to specifically include wording that disallows welded patches. Please see Attachment #5.

Attachment #2



**Excerpt from WGS Operations and Maintenance Manual,
consisting of section 3.13 which addresses
repair criteria in non-covered segments**

3.13 Repair Procedures and Documentation for Gas Transmission Pipelines

CODE REFERENCE: Title 49CFR Sections 192.150, 192.241, 192.309, 192.485, 192.605, 192.703, 192.711, 192.713, 192.714, 192.715, and 192.717.

PURPOSE: To define defects in steel pipeline and specify the acceptable method for their disposition.

SCOPE & APPLICABILITY: Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly. The company may not operate a segment of pipeline, unless it is maintained in accordance with subpart M, Maintenance, 192.701-755. When a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management is discovered, the condition must be remediated as prescribed by §192.933(d) – if the pipeline is subject to IMP.

For onshore transmission pipelines not located in high consequence areas, Lodi Gas Storage shall remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless the criteria below specify otherwise, WGS shall calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME B31.8S section 7, Figure 7.2.1-1. WGS shall remediate conditions according to the following criteria:

- **Immediate Repair Conditions** – Repair the following conditions immediately upon discovery following the evaluation and remediation schedule in section 7 of ASME B31.8S:
 1. Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.
 2. A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 3. Metal loss greater than 80 percent of nominal wall regardless of dimensions.
 4. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than

1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

5. A crack or crack-like anomaly with: (1) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness, or (2) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth.
 6. An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.
- **Two-year Conditions** – Repair the following conditions within two years of discovery:
 1. A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 2. A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 3. A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 4. For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S (incorporated by reference, see § 192.7), section 7, Figure 7.2.1-1.
 5. Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance

with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

6. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 7. A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- **Monitored Conditions** – Record and monitor the following conditions during subsequent risk assessments and integrity assessments for any changes that may require remediation:
 1. A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded.
 2. 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 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.
 3. A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

4. A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
5. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
6. A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

Operating pressure must be at a safe level during repair operations. Immediate temporary measures shall be taken to protect life, property, and the environment from hazards resulting from a leaking, defective, or damaged pipeline.

Immediately upon discovery and until WGS remediates the “Immediate Repair Conditions” specified in this procedure, or upon a determination that WGS is unable to respond within the time limits for the “Two-year Conditions” specified in this procedure, WGS shall reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

- A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
- A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or
- A level not exceeding the predicted failure pressure divided by 1.1.

WGS shall notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required by this procedure and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from evaluation, remediation, or pressure reduction requirements.

When a pressure reduction exceeds 365 days, WGS shall notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

Determine the repair method according to the type of damage or defect.

- In situ direct examination of crack defects. Whenever a condition is found that requires the pipeline to be repaired, WGS shall perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. “In situ” examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

Use the unpressurized repair alternate if either of the following two conditions exist (pipeline must be out of service and blown-down):

- Pipe geometry is deformed so it prevents proper installation of a pressurized repair.
- Leakage makes pressurized repair unsafe.

A pressurized repair is one that is carried out while the pressure in the pipeline is higher than atmospheric.

If a pressurized repair is made, reduce the pressure of the line to the limit established by each repair method or as established in Section 3.8 Operating Pressure Limits during Maintenance and Repair of this manual.

All repair methods established by this procedure are considered permanent. The use of a leak clamp is considered only as a temporary measure that may be taken to protect life and property.

After repairing a leak, verify that the leak has been contained and no additional leaks exist in the immediate area.

Except as provided in the next two paragraphs below, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line

component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

The above paragraph does not apply to:

- Manifolds
- Station piping such as at compressor stations, meter stations, or regulator stations
- Piping associated with storage facilities, other than a continuous run of pipeline between a compressor station and station facilities
- Crossovers
- Sizes of pipe for which an instrumented internal inspection device is not commercially available
- Transmission lines, operated in conjunction with a distribution system which is installed in Class 4 locations
- Other piping that, under 49CFR 190.9 finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

An operator encountering emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a transmission line if the operator determines and documents why it is prohibitive to comply with design and construction requirements for each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced. Within 30 days after discovering the emergency or construction problem the operator must petition, under Title 49 CFR 190.9, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

PROCEDURE: No operator may use any pipe, valve, or fitting for replacement or repairing pipeline facilities unless it is designed and constructed as required by Part 192.

PRELIMINARY INVESTIGATIONS - Inspect any exposed pipeline for leaks, impact damage, coating conditions, and external corrosion.

- Visually inspect buried welds whenever the coating has been removed for any reason.
- Make a preliminary assessment to determine the extent of the damage or defect. In most cases a visual inspection is sufficient. Use X-ray or other forms of inspection that could be considered helpful if conditions warrant.
- Investigate to determine the cause of any leaks that are found.
- Determine if a safety related condition exists and whether it should be reported.

- Document investigation on **WGS Form 115 Leak Investigation Report** Form.

EVALUATION OF DAMAGE EXTENT

Make a precise evaluation of the extent of any damage or defect (refer to Table 3.13A.)

REPAIR OF CORROSION CONDITION

General Corrosion:

- Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.

References for determining the remaining strength of a pipeline are:

- ASME/ANSI B31G (Latest Edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."
- AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", Latest Edition.

Localized Corrosion Pitting:

- Each segment of transmission line with localized corrosion pitting to a degree where leakage might result must be repaired or removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits. Inspect the interior of the cutout and the ends of the remaining pipe for internal corrosion, record on **WGS Form 112 Corrosion Control Report**.

Repair of Imperfections and Damages

- Except as provided below, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of specified minimum yield strength must be repaired as follows:
 - If it is feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

- If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage. Repair sleeves shall be welded using a qualified procedure specifying low hydrogen rod.
 - The pipeline can be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
 - Operating pressure must be at a safe level during repair operations, see O&M Procedure 3.8 for guidance.
- Submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

Repair of Welds

- If it is feasible to take the segment of transmission line out of service, the weld must be repaired per Section 3.17 Welding of this manual.
- A weld may be repaired in accordance with repair or removal of defective welds per applicable code and standard while the segment of transmission line is in service if:
 - The weld is not leaking;
 - The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the specified minimum yield strength (SMYS) of the pipe; and
 - Grinding of the defective area can be limited so that at least 1/8 inch (3.2 mm) thickness in the pipe weld remains.

A defective weld, which cannot be repaired in accordance with the above paragraphs, must be repaired by installing a full encirclement welded split sleeve of appropriate design.

Repair of Leaks

- If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.
- If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design.
- If the leak is due to a corrosion pit, the repair may be made temporarily by installing a properly designed bolt-on-leak clamp.
- Either the sleeve or the clamp is to be removed and replaced by a cylindrical piece as soon as it is feasible to take the piping out of service.
- All repairs performed must be tested and inspected.

Testing of Repairs

- Testing of replacement pipe:
 - The replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.
- Inspection and test of welds:
 - Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure and the requirements of API Standard 1104, "Welding of Pipelines and Related Facilities".
 - The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be nondestructively tested in accordance with Section 3.15 Testing Requirements, of this manual except that welds that are visually inspected and approved by a qualified welder inspector need not be nondestructively tested if:
 - ❖ The pipe has a nominal diameter of less than 6 inches (152 min); or
 - ❖ The pipeline is to be operated at a pressure that produces a hoop stress of less than 40% of SMYS and the welds are limited in number and nondestructive testing is impractical.
 - The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in API Standard 1104, Section 9.
 - WGS shall not use a welded patch as a means of repair.

RECORDS: Complete **WGS Form 109 Pipeline Leak Repair Report**, **WGS Form 112 Corrosion Control Report**, and **WGS Form 115 Leak Investigation Report** as applicable.

Submit as-built sketches to the Operations Manager if pipe is replaced.

Maintain the records for the life of the pipeline facility.

RELATED CODE, PROCEDURES AND FORMS

Table 3.13A
PIPELINE REPAIR – PIPE DAMAGE OR DEFECT

DAMAGE OR DEFECT	DISPOSITION OF CONDITION	
	Unpressurized	Pressurized
Dent on:		
Welds	C	E, P
Body or pipe 12" (305 mm) or less nominal diameter:		
Depth greater than ¼" (6.4)	C	E, P
Body or pipe 12" (305 mm) nominal diameter:		
2% or more of nominal diameter	C	E, P
Groove, gouge or scratch with remaining wall thickness:		
Less than design wall thickness	C	E, P
Welds:		
No Leak	X	E, P
With Leak (see note 2)	X	E, P
General Corrosion:		
No Leak	C	C, M
Localized Corrosion Pitting:		
No Leak	C	E,C,M,P
With Leak (see note 2)	C	L,E,P
All Other Leaks (see note 2)	C	E, P

Legend:

- C Cutting out a cylindrical piece of pipe and replacing it with pretested pipe of similar or greater design strength.
- E Full encirclement, welded split sleeve of appropriate design.
- L Leak clamp.
- M Establish new maximum operating pressure base on the actual remaining wall thickness.
- P Plidco sleeve or equivalent (submerged).
- R Weld Repair (see note 1).
- X Cut out repair per applicable code and standard.

Notes:

A weld on a pressurized pipeline segment may be repaired if:

1. The pressure in the segment is reduced so that it does not produce a stress that is more than 20% of the specified minimum yield strength of the pipe; and
2. Grinding of the defective area can be limited so that at least 1/8 inch (3.2 mm) thickness in the pipe weld remains.
3. Either the sleeve or the leak clamp are to be removed and replaced by a cylindrical piece as soon as it is feasible to take the piping out of service.

Attachment #3



**Excerpt from WGS Operations and Maintenance Manual
section 8.3 highlighting revisions to address
reassessments when using the Engineering Critical Assessment method**

strength of 24,000 psi in accordance with O&M Manual, Section 2.10 Maximum Allowable Operating Pressure.

**PROCEDURE – ENGINEERING CRITICAL ASSESSMENT (ECA) FOR
MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)
RECONFIRMATION:**

7. ECA Analysis

- a. The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with this procedure. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by O&M Manual, Section 2.3 Investigation of Failures and Serious Incidents, Procedure 8.2 and Integrity Management.
- b. The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:
 - (1) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with Procedure 8.2 .
 - (2) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI

B31G (incorporated by reference, see §192.7) or R-STRENG (incorporated by reference, see §192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

- (3) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.
 - (4) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using Section 5 of this procedure.
 - c. The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.
 - d. The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in O&M Manual, Section 3.15 Testing Requirements..
- 8. Assessment to determine defects remaining in the pipe. You must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with this procedure.
 - a. Use of a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the

date of the pressure test in accordance with Procedure 8.2. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in Procedure 8.2.

- b. Use of an inline inspection program in accordance with this procedure.
 - c. Use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with O&M Manual, Section 2.1 Pipeline Reporting. The “other technology” notification must have:
 - (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
 - (2) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.
9. In-line inspection. An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.
- a. If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.
 - b. If the pipeline has had a reportable incident, as defined in O&M Manual, Section 2.1 Pipeline Reporting, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes

- an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.
- c. Inline inspection must be performed in accordance with Procedure 8.2 .
 - d. You must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. Have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.
 - e. Interpretation and evaluation of assessment results must meet the requirements of O&M Manual, Section 3.13 Repair Procedures and Documentation for Gas Transmission Pipelines, Procedure 8.2 and Integrity Management, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.
 - f. Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in O&M Manual, Section 3.13 Repair Procedures and Documentation for Gas Transmission Pipelines and Integrity Management.
10. Defect remaining life. If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with Procedure 8.2.
11. Reassessments. If an ECA analysis is performed for dents and other mechanical damage or cracks and crack-like defects to determine the

maximum reevaluation intervals, WGS shall assess the anomalies as follows:

- a. If the anomaly is in an HCA, WGS shall reassess the anomaly within a maximum of 7 years in accordance with WGS IMP Section 5.3, unless the safety factor is expected to go below what is specified in Section 7 of this procedure.
- b. If the anomaly is outside of an HCA, WGS shall reassess the anomaly within a maximum of 10 years in accordance with WGS O&M Procedure 8.2, unless the anomaly safety factor is expected to go below what is specified in Section 7 of this procedure.

RELATED CODE, PROCEDURES AND FORMS:

O&M Manual, Section 2.1 Pipeline Reporting

8.3 Material Verification and ECA

8.1 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines

O&M Manual, Section 3.13 Repair Procedures and Documentation for Gas Transmission Pipelines

IMP, Section 5.3 Integrity Assessment, Continual Evaluation and Reassessment

O&M Manual, Section 3.15 Testing Requirements

RECORDS:

12. Documentation of material properties and attributes. Records established under This section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method in Procedure 8.1 or the fracture mechanics requirements in Procedure 8.2 must be maintained for the life of the pipeline.
13. Retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

CODE REFERENCE: 49 CFR 192.607, 632

Attachment #4



**Excerpt from WGS Integrity Management Program Manual,
consisting of section 5.5 which addresses
repair procedures for covered segments**

impracticable to obtain the information within the time limit. The required response schedule interval begins at the time the condition is discovered.

- 5.4.3 The actual date of discovery must be documented on the remediation schedule (e.g., Master Action Item Tracking Log).
- 5.4.4 Once the discovery is made, a schedule that prioritizes evaluation and remediation of anomalous conditions will be developed according to the requirements of Section 5.5. If the schedule cannot be met, the reason(s) why the schedule cannot be met and the basis for why the revised schedule will not jeopardize public safety must be documented and retained in file.
- 5.4.5 If required timelines for responding to conditions cannot be met, the operating pressure of the pipeline must be temporarily reduced, or other action must be taken that will ensure safety of the covered segment.
- 5.4.6 Temporary reduction in operating pressure must be determined using ASME B31G or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG"), or by reducing the operating pressure to a level not to exceed 80% of the level at the time the condition was discovered.
- 5.4.7 Notification must be made to the PHMSA and the CPUC Utilities Safety Enforcement Division if:
 - i. The schedule for evaluation and remediation cannot be met and safety cannot be provided through temporary reduction in operating pressure or other action.
 - ii. Pressure reduction exceeds 365 days. The notification must explain the reason for the remediation delay and include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

5.5 Remediation Schedule

- 5.5.1 WGS must take prompt action to address all anomalous conditions discovered through integrity assessments. In addressing all conditions, WGS must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. WGS must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed shall use pipe and material properties that are documented in traceable, verifiable, and complete records. Except for those conditions meeting the criteria described in Sections 5.5.2 through 5.5.4 below which have special requirements for scheduling remediation, all conditions found in the covered segment in the high consequence area must be scheduled and remediated according to the following:
 - i. Temporary pressure reduction.
 - a. If WGS is unable to respond within the time limits for certain conditions specified in this procedure, WGS must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. WGS must reduce the operating pressure to one of the following:

- A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
 - A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or
 - A level not exceeding the predicted failure pressure divided by 1.1.
- b. WGS must determine the predicted failure pressure in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11. WGS must notify PHMSA if it cannot meet the schedule for evaluation and remediation and cannot provide safety through a temporary reduction in operating pressure or other action. WGS must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.
- ii. Long-term pressure reduction. When a pressure reduction exceeds 365 days, WGS must notify PHMSA and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

Anomalies discovered in segments in non-high consequence areas must be repaired according to WGS O&M Procedure 3.13 in accordance with 49 CFR Part 192, subpart M. The special requirements for Sections 5.5.2 through 5.5.4 do not apply to anomalies in non-high consequence areas. Remediation for non-integrity management issues found in non-high consequence areas must be scheduled according to the WGS O&M Manual.

5.5.2 Immediate Repair Conditions

An immediate repair condition requires a temporary pressure reduction or shut down of the pipeline upon discovery and must be scheduled and remediated according to the provision of ASME B31.8S, Section 7, Figure 4, "Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan".. Immediate repair conditions are classified as:

- i. A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined by ASME B31G or an equivalent method of remaining strength calculation less than or equal to 1.1 times the MAOP at the location of the anomaly.
- ii. A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with WGS Operations & Maintenance Manual Procedure 8.3 Section 7 demonstrate critical strain levels are not exceeded.
- iii. Metal loss greater than 80 percent of nominal wall regardless of dimensions.

- iv. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 is less than 1.25 times the MAOP.
- v. A crack or crack-like anomaly meeting any of the following criteria:
 - a. Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness; or
 - b. Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth.
- vi. An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

5.5.3 One-Year Conditions

One-year conditions require remediation within one year of discovery. Wild Goose shall follow requirements of ASME B31.8-2007 for the engineering analysis demonstrating critical strain levels are not exceeded for deformed pipe (see ASME B31.8 section 851.4 and ASME B31.8 Appendix R).

One-year conditions are classified as any of the following:

- i. A smooth 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, unless engineering analyses performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- ii. Dent with a depth greater than 2% of the pipeline's diameter that affects pipe curvature at a girth weld or at a longitudinal or helical seam weld, unless engineering analyses performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- iii. A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- iv. Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11, less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, WGS shall follow the remediation schedule specified in ASME B31.8S section 7, Figure 7.2.1-1.
- v. Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that

has a predicted failure pressure, determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11, of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

- vi. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11, is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- vii. A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11, that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

5.5.4 Monitored Conditions

Monitored conditions are the least severe of those described in sections 5.5.2 through 5.5.4. If they are not expected to grow to critical dimensions prior to the next scheduled assessment, then they will not require examination and evaluation until the next scheduled integrity assessment interval defined by Table 7. These anomalies will be recorded in the master data spreadsheet and monitored during subsequent risk or integrity assessments for any change in their status that would require remediation. Wild Goose shall follow requirements of ASME B31.8-2007, Appendix R for the engineering analysis demonstrating critical strain levels are not exceeded.

Monitored conditions are classified as:

- 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), and for which engineering analyses of the dent, performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- 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 NPS 12), and for which engineering analyses of the dent, performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- iii. A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with WGS

Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.

- iv. A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11 demonstrate critical strain levels are not exceeded.
- v. Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance WGS Operations & Maintenance Manual Procedure 8.2 Section 11, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- vi. A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with WGS Operations & Maintenance Manual Procedure 8.2 Section 11, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

5.6 Repair Methods

- 5.6.1 For the covered segment, WGS shall excavate, directly examine, and where necessary, repair or remediate all indications, which are classified as defects. The appropriate defect repair process will be reviewed and selected by the Senior Storage Facilities Engineer for each defect investigated. WGS IMP Appendix G, "Defect Assessment Protocols", provides guidance for these decisions. For anomalies located outside of the covered segment, WGS shall follow the code requirements of 49 CFR Part 192, section 192.703 and other applicable sections.

For leak repairs, only the following permanent repair method is allowable: Cutout and Replacement.

For non-leaking defect remediation, the following repair options are applicable:

External or Mechanical Defects:

- 1. Cutout and Replacement;
- 2. Type 'A' Steel Reinforcing Sleeve;
- 3. Type 'B' Pressure Containment Sleeve;
- 4. Composite Repair Sleeve; and
- 5. Grinding Repair.

Internal Defects:

- 1. Cutout and Replacement; and
- 2. Type 'B' Pressure Containment Sleeve.

A summary of each repair method is included in sections 5.6.2 to 5.6.7:

Attachment #5



**Excerpt from WGS Operations and Maintenance Manual
section 3.13 highlighting revisions to address welded patches**

Testing of Repairs

- Testing of replacement pipe:
 - The replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.
- Inspection and test of welds:
 - Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure and the requirements of API Standard 1104, "Welding of Pipelines and Related Facilities".
 - The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be nondestructively tested in accordance with Section 3.15 Testing Requirements, of this manual except that welds that are visually inspected and approved by a qualified welder inspector need not be nondestructively tested if:
 - ❖ The pipe has a nominal diameter of less than 6 inches (152 min); or
 - ❖ The pipeline is to be operated at a pressure that produces a hoop stress of less than 40% of SMYS and the welds are limited in number and nondestructive testing is impractical.
 - The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in API Standard 1104, Section 9.
 - WGS shall not use a welded patch as a means of repair.

RECORDS: Complete **WGS Form 109 Pipeline Leak Repair Report**, **WGS Form 112 Corrosion Control Report**, and **WGS Form 115 Leak Investigation Report** as applicable.

Submit as-built sketches to the Operations Manager if pipe is replaced.

Maintain the records for the life of the pipeline facility.

RELATED CODE, PROCEDURES AND FORMS